California Environmental Protection Agency

Air Resources Board

PUBLIC MEETING AGENDA

Thursday, December 16, 2010

and

Friday, December 17, 2010

LOCATION:
Air Resources Board
Byron Sher Auditorium, Second Floor
1001 I Street
Sacramento, California 95814

This facility is accessible by public transit. For transit information, call (916) 321-BUSS, website: http://www.sacrt.com
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TO SUBMIT WRITTEN COMMENTS ON AN AGENDA ITEM IN ADVANCE OF THE MEETING GO TO: http://www.arb.ca.gov/lispub/comm/bclist.php

December 16, 2010
9:00 a.m.

DISCUSSION ITEMS:
Note: The following agenda items may be heard in a different order at the Board meeting.

Agenda Item #

10-11-1: Public Hearing to Consider the Adoption of a Proposed California Cap on Greenhouse Gas Emissions and Market-Based Compliance Mechanisms Regulation, Including Compliance Offset Protocols

Staff will present to the Board a proposed regulation to implement a California Greenhouse Gas Emissions Cap-and-Trade Program, including compliance offset protocols. The proposed regulation would establish the framework and requirements for the program.

10-11-2: Public Hearing to Consider Amendments to the Regulation for Mandatory Reporting of Greenhouse Gas Emissions

Staff is proposing amendments to the Regulation for the Mandatory Reporting of Greenhouse Gas Emissions. The proposed amendments would align most California greenhouse gas reporting requirements with the federal greenhouse gas reporting requirements adopted by the United States Environmental Protection Agency, and will add specific provisions to support the Air Resources Board's proposed Cap-and-Trade regulation.

December 17, 2010
8:30 a.m.
(Spanish Interpretation Services Available 12/17 Only)

Agenda Item #

10-11-3: Public Hearing to Consider the Adoption of Proposed Amendments to the Regulation to Reduce Emissions of Diesel Particulate Matter, Oxides of Nitrogen and Other Criteria Pollutants From In-Use On-Road Diesel-Fueled Vehicles, the Heavy-Duty Vehicle Greenhouse Gas Emission Reduction Measure, and the Regulation to Control Emissions From In-Use On-Road Diesel-Fueled Heavy-Duty Drayage Trucks at Ports and Intermodal Rail Yard Facilities

Notice of Public Hearing to Consider Proposed Amendments to the Regulations for In-Use Off-Road Diesel-Fueled Fleets and Off-Road Large Spark Ignition Engine Fleet Requirements

Staff is proposing amendments to five regulations - the Regulation for In-Use On-Road Diesel Vehicles (Truck and Bus regulation), the Heavy-Duty Vehicle Greenhouse Gas Emission Reduction Regulation (Tractor-Trailer GHG regulation), the Regulation for In-Use On-Road Diesel-Fueled Heavy-Duty Drayage Trucks (Drayage Truck regulation), the In-Use Off-Road Diesel Fueled Fleets (Off-Road regulation), and the Large Spark-Ignition (LSI) fleet regulation.

In order to implement the directives given by the Board in April 2010, staff is proposing amendments to the Truck and Bus regulation and Off-Road regulation to provide relief to fleets adversely affected by the economy, and take into account the fact that emissions are lower than previously predicted. Both regulations will be considered together to identify an equitable proposal to reduce the compliance costs of both regulations, while still providing the necessary emission reductions to meet the Board's State Implementation Plan commitments and protect public health.

The proposed amendments to the Truck and Bus regulation will provide economic relief for fleets by eliminating requirements for trucks with a gross vehicle weight rating less than 26,001 pounds, and by easing the compliance schedule for heavier trucks. The proposed amendments to the Off-Road regulation will delay the initial compliance date, significantly reduce annual requirements, and provide a path to compliance without any required retrofits. The proposed amendments to both regulations will substantially simplify the regulations while retaining flexibility for fleets, and will give credit to fleets that have already taken actions to comply with the regulations. The overall effect of the proposed amendments will be to significantly lower the costs of the regulations while still maintaining progress toward clean air.

Staff will also propose amendments to the Drayage Truck regulation to add flexibility to fleets' compliance schedules, mitigate the use of noncompliant trucks outside port and rail properties, and to provide for a smooth transition to the Truck and Bus regulation. The proposed amendments to the Tractor-Trailer GHG regulation will add flexibility to fleets' compliance schedules and reporting requirements while still meeting the GHG emissions reduction goals of the regulation. The amendments also address requirements for storage trailers and refrigerated van trailers.

Finally, staff will propose amendments to the LSI regulation that make several minor changes and clarifications, including extending the limited hours of use provisions and broadening compliance extension flexibility.

CLOSED SESSION – LITIGATION

The Board will hold a closed session, as authorized by Government Code section 11126(e), to confer with, and receive advice from, its legal counsel regarding the following pending or potential litigation:

Pacific Merchant Shipping Association v. Goldstene, U.S. District Court (E.D. Cal Fresno), Case No. 2:09-CV-01151-MCE-EFB.

American Trucking Associations, et al. v. U.S. Environmental Protection Agency, et al., U.S. Court of Appeals, District of Columbia Circuit, Case No. 09-1090.

POET, LLC, et al. v. Goldstene, et al., Superior Court of California (Fresno County), Case No. 09CECG04850.

Rocky Mountain Farmers Union, et al. v. Goldstene, U.S. District Court (E.D. Cal. Fresno), Case No. 1:09-cv-02234-LJO-DLB.

National Petrochemical & Refiners Association, et al. v. Goldstene, et al., U.S. District Court (E.D. Cal. Fresno) Case No. 1:10-cv-00163-AWI-GSA.

Association of Irritated Residents, et al. v. California Air Resources Board, Superior Court of California (San Francisco County), Case No. CPF-09-509562.

OPPORTUNITY FOR MEMBERS OF THE BOARD TO COMMENT ON MATTERS OF INTEREST

Board members may identify matters they would like to have noticed for consideration at future meetings and comment on topics of interest; no formal action on these topics will be taken without further notice.

OPEN SESSION TO PROVIDE AN OPPORTUNITY FOR MEMBERS OF THE PUBLIC TO ADDRESS THE BOARD ON SUBJECT MATTERS WITHIN THE JURISDICTION OF THE BOARD

Although no formal Board action may be taken, the Board is allowing an opportunity to interested members of the public to address the Board on items of interest that are within the Board's jurisdiction, but do not specifically appear on the agenda. Each person will be allowed a maximum of three minutes to ensure that everyone has a chance to speak.

TO SUBMIT WRITTEN COMMENTS ON AN AGENDA ITEM IN ADVANCE OF THE MEETING GO TO:

http://www.arb.ca.gov/lispub/comm/bclist.php

IF YOU HAVE ANY QUESTIONS, PLEASE CONTACT THE CLERK OF THE BOARD:
OFFICE: (916) 322-5594
1001 I Street, Floor 23, Sacramento, California 95814
ARB Homepage: www.arb.ca.gov

SPECIAL ACCOMMODATION REQUEST

Special accommodation or language needs can be provided for any of the following:

- An interpreter to be available at the hearing;
- Documents made available in an alternate format (i.e., Braille, large print, etc.) or another language;
- A disability-related reasonable accommodation.

To request these special accommodations or language needs, please contact the Clerk of the Board at (916) 322-5594 or by facsimile at (916) 322-3928 as soon as possible, but no later than 10 business days before the scheduled Board hearing. TTY/TDD/Speech to Speech users may dial 711 for the California Relay Service.

Comodidad especial o necesidad de otro idioma puede ser proveído para alguna de las siguientes:

- Un intérprete que esté disponible en la audiencia;
- Documentos disponibles en un formato alterno (por decir, sistema Braille, o en impresión grande) u otro idioma;
- Una acomodación razonable relacionados con una incapacidad.

Para solicitar estas comodidades especiales o necesidades de otro idioma, por favor llame a la oficina del Consejo al (916) 322-5594 o envíe un fax a (916) 322-3928 lo más pronto posible, pero no menos de 10 días de trabajo antes del día programado para la audiencia del Consejo. TTY/TDD/Personas que necesiten este servicio pueden marcar el 711 para el Servicio de Retransmisión de Mensajes de California.

SMOKING IS NOT PERMITTED AT MEETINGS OF THE CALIFORNIA AIR RESOURCES BOARD

California Environmental Protection Agency

Air Resources Board

PUBLIC MEETING AGENDA

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December 16, 2010 at 9:00 a.m.

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TITLE 17. CALIFORNIA AIR RESOURCES BOARD

NOTICE OF PUBLIC HEARING TO CONSIDER THE ADOPTION OF A PROPOSED CALIFORNIA CAP ON GREENHOUSE GAS EMISSIONS AND MARKET-BASED COMPLIANCE MECHANISMS REGULATION, INCLUDING COMPLIANCE OFFSET PROTOCOLS

The Air Resources Board (ARB or Board) will conduct a public hearing at the time and place noted below to consider adoption of a proposed regulation to implement a California greenhouse gas emissions cap-and-trade program, including compliance offset protocols.

DATE: December 16, 2010

TIME: 9:00 a.m.

PLACE: California Environmental Protection Agency
Air Resources Board
Byron Sher Auditorium
1001 I Street
Sacramento, California 95814

This item may be considered at a two-day meeting of the Board, which will commence at 9:00 a.m. on December 16, 2010, and may continue at 8:30 a.m. on December 17, 2010. Please consult the agenda for the hearing, which will be available at least ten days before December 16, 2010, to determine the day on which this item will be considered.

INFORMATIVE DIGEST OF PROPOSED ACTION AND POLICY STATEMENT OVERVIEW

Sections Affected: Proposed adoption of California Code of Regulation, title 17, new article 5, which contains new sections 95800, 95801, 95802, 95810, 95811, 95812, 95813, 95814, 95820, 95821, 95830, 95831, 95832, 95840, 95841, 95850, 95851, 95852, 95852.1, 95852.2, 95852.3, 95853, 95854, 95855, 95856, 95857, 95870, 95890, 95891, 95892, 95893, 95910, 95911, 95912, 95913, 95914, 95915, 95920, 95921, 95922, 95940, 95941, 95942, 95943, 95970, 95971, 95972, 95973, 95974, 95975, 95976, 95977, 95978, 95979, 95980, 95981, 95982, 95983, 95984, 95985, 95986, 95987, 95988, 95990, 95991, 95992, 95993, 95994, 95995, 95996, 95997, 95998, 96010, 96011, 96012, 96013, 96020, 96021, and 96022.

Background:

The California Global Warming Solutions Act of 2006 (Assembly Bill 32; Stats. 2006, Chapter 488) (AB 32) authorizes ARB to implement a comprehensive, multi-year program to reduce greenhouse gas (GHG) emissions in California. AB 32 required ARB to develop a scoping plan to reduce GHG emissions in California to 1990 levels by 2020. ARB's adopted Scoping Plan includes a comprehensive set of actions designed

to reduce GHG emissions in California, improve the environment, reduce dependence on foreign oil, diversify energy sources, save energy, create new jobs, and enhance public health. Meeting the goals of AB 32 requires a coordinated set of strategies to reduce GHG emissions throughout the economy that work within a comprehensive tracking, reporting, verification and enforcement framework. The Scoping Plan includes a variety of measures to achieve AB 32 goals, including direct regulations, performance-based standards, and market-based mechanisms. The measures included in the Scoping Plan continue to be developed through an open public process and will be in place by 2012. Many of the measures in the Scoping Plan complement and reinforce each other.

The Scoping Plan directs ARB staff to develop a cap-and-trade regulation, which is a type of market-based compliance mechanism. Once implemented, the cap-and-trade regulation will provide a fixed limit on GHG emissions from the sources responsible for about 85 percent of the state's total GHG emissions. The cap-and-trade regulation will reduce GHG emissions by applying a declining aggregate cap on GHG emissions, and will also create a flexible compliance system through the use of tradable instruments (allowances and offset credits). The regulation is designed to link up with partners in other jurisdictions, beginning with the Western Climate Initiative (WCI).

In 2007, California helped establish the Western Climate Initiative, a cooperative effort of seven U.S. states and four Canadian provinces (the "partners") that are collaborating to identify, evaluate, and implement policies to reduce GHG emissions, including the design and implementation of a regional cap-and-trade program. ARB has consulted with the partners in formulating the proposed regulation, and anticipates linking to programs promulgated by the partners as they are adopted.

ARB staff conducted an extensive public process during the development of the California cap-and-trade regulation. Through 2009 and 2010, staff developed the overall options for program design and development. ARB staff conducted extensive public consultation, including more than 35 public meetings, to discuss and share ideas with the general public and key stakeholders on the appropriate structure of the cap-and-trade program. In November 2009, staff released a conceptual framework for the cap-and-trade regulation, called the Preliminary Draft Regulation (PDR), and held a workshop on the draft in December. Staff received over 130 written comments in response to the PDR. Staff also met regularly with individual stakeholders to hear their concerns and recommendations. ARB staff collected public comments during each public workshop, which focused on key topics and program design components.

ARB also received input and advice from the Market Advisory Committee and two advisory committees created under AB 32: the Economic and Technology Advancement Advisory Committee (ETAAC) and the Environmental Justice Advisory Committee (EJAC). In addition, in May 2009 ARB, in conjunction with Cal/EPA, convened the Economic and Allocation Advisory Committee (EAAC), which included economic, financial, and policy experts. The EAAC provided recommendations on cap-and-trade

program design and reviewed ARB's updated economic analysis on the Scoping Plan that was completed in March 2010.

Description of the Proposed Regulatory Action

After considering the comments received, ARB staff is proposing a regulation that would establish the framework and requirements for California's GHG cap-and-trade program. Cap and trade is a regulatory approach that would control GHGs from major emission sources ("covered entities") by setting a firm limit (the "cap") on GHG emissions while employing market mechanisms to cost-effectively achieve the emission reduction goals. The cap for GHG emissions from major sources would commence in 2012 and decline over time, achieving emissions reductions throughout the program's duration. The cap is measured in metric tons of carbon dioxide equivalent ($MTCO_2e$). Covered entities will be able to buy permits to emit (allowances) at auction, purchase allowances from others, or purchase offset credits (the "trade"). Allowances and offset credits are more fully discussed below.

The cap-and-trade program would establish the total amount of GHG emissions that major sources would be allowed (permitted) to emit. ARB would distribute allowances to emit GHGs, and the total number of allowances created would be equal to the total amount ("aggregate cap") set for cumulative emissions from all covered entities. Each allowance would permit the holder to emit one $MTCO_2e$ of GHG. Covered entities include major GHG emitting sources, such as electricity generation, including imports, and large stationary sources (i.e. refineries, cement production facilities, oil and gas production facilities, glass manufacturing facilities, food processing plants) that emit more than 25,000 $MTCO_2e$ per year, as well as natural gas and propane fuel providers and transportation fuel providers.

The cap-and-trade program is one of the key measures included in the Scoping Plan to reduce GHG emissions. Covered entities under the cap may also be subject to other measures, standards, and regulations, including improved building efficiency standards, vehicle efficiency measures and applicable air pollution regulations.

Applicability

Starting in 2012, the proposed regulation would include covered entities emitting more than 25,000 $MTCO_2e$. This includes GHG emissions from electricity generation, including imports; industrial combustion at large stationary sources; and industrial process emissions for which adequate quantification methods exist. The program will expand in 2015 to include fuel distributors to address emissions from transportation fuels, and from combustion of other fossil fuels not covered directly at large sources in the initial phase of the program. The first three years of the proposed regulation are known as the "first compliance period," and the second three years are known as the "second compliance period."

The first compliance period would include sources responsible for more than one-third of the economy-wide emissions in California. Starting with the second compliance

period, the program would include major sources of GHG emissions responsible for about 85 percent of emissions. ARB could choose to expand the applicability of the program to include additional covered entities over time based on new information.

The proposed regulation defines and includes requirements for covered entities, opt-in covered entities, voluntarily associated entities, and other registered participants. Opt-in covered entities are industries with processes and operations that would make them covered entities except that their emissions do not exceed the 25,000 $MTCO_2e$ threshold, and that choose to participate in the cap-and-trade program. Opt-in covered entities are subject to the proposed regulation as if they exceeded the 25,000 $MTCO_2e$ threshold, including reporting, verification and compliance requirements and eligibility for allowance distribution. Voluntarily associated entities are parties such as the general public, investment banks, land use easements and private citizen groups that would be allowed to hold allowances and offsets, and would be subject to registration and reporting requirements. Other registered participants include verifiers or verification bodies, which could be private or government organizations; these participants cannot participate in trading and cannot hold compliance instruments. Under the proposed regulation, covered entities and opt-in covered entities would be required to register with ARB, report their emissions annually, acquire compliance instruments, and surrender compliance instruments to match their emissions for the compliance period. Voluntarily associated entities would also need to apply and register with ARB.

The proposed cap-and-trade regulation would apply to the following GHGs: carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), sulfur hexafluoride (SF_6), and nitrogen trifluoride (NF_3). In a separate rulemaking action, ARB's existing mandatory reporting regulation is also being amended to support the cap-and-trade program.

Compliance Instruments

The proposed regulation would create two kinds of "compliance instruments" to allow covered entities to meet their obligations under the cap: allowances and offset credits. Approved compliance instruments would be issued by ARB or other programs that are approved by the Board. Each allowance or offset credit would represent one $MTCO_2e$.

Allowances

The cap would be divided into annual budgets that specify the number of allowances created for each year from 2012 through 2020. The initial 2012 allowance budget is based on the best estimate of actual emissions in 2012 for those sources that would be covered at the start of the cap-and-trade regulation. The cap would then decline each year beginning in 2013, and fewer allowances would be issued on an annual basis. In 2015, the program would expand to cover providers of transportation fuels and residential and commercial fuels. Therefore, the initial 2015 allowance budget reflects the addition of these GHG emissions, with the increase based on the best estimate of the actual emissions in 2015 for those sources added to the program that year. The

cap will then decline until 2020. The 2020 cap will be set at a level designed to allow California to achieve the AB 32 target in 2020.

The allowances will be distributed through a combination of free allocation and sale at auction. The proposed regulation includes a basic framework for the distribution of allowances. Staff anticipates significant comments on this framework, and will consider those comments in working to develop a more specific system for allowance distribution that can be incorporated into the final regulation.

Offset Credits

An offset credit is a compliance instrument that represents a reduction or removal of one $MTCO_2e$ of GHGs resulting from an activity not covered by the cap that can be measured, quantified, and verified. This credit can then be sold and used by a covered entity to meet a portion of its compliance obligation under the regulation. Covered entities can use offset credits to satisfy up to eight percent of the entity's total compliance obligations. Although the source that produces an offset would not be covered under the regulation, it can generate reductions for use by entities that must comply with the cap. Offset credits would need to meet criteria identified in the proposed regulation that demonstrate that the emission reductions are real, permanent, verifiable, enforceable, quantifiable, and additional.

The proposed regulation also includes a process for offset credits from qualified existing offset projects operating under specific offset protocols to be accepted into the compliance offsets program. The proposed regulation also establishes a framework for accepting sector-based offset credits from developing countries, though additional evaluation would be needed before such credits could come into the program.

Offset Protocols

ARB is proposing four compliance offset protocols for the Board to consider as part of the regulation: Compliance Offset Protocol for U.S. Ozone Depleting Substances Projects, Compliance Offset Protocol for Livestock Manure (Digester) Projects, Compliance Offset Protocol for Urban Forest Projects, and Compliance Offset Protocol for U.S. Forest Projects. The Board will consider each of these protocols as part of the proposed regulation and staff is proposing that approval of the regulation will include approval of these offset protocols. Projects using the offset protocols are subject to verification and enforcement requirements that are specified in the proposed regulation. The protocols are incorporated into the regulation by reference, and changes will require future Board action. However, changes to quantification methodologies are exempt from the Administrative Procedure Act (APA). An offset project operator using ARB approved protocols would need to publicly list its project and register with ARB or an ARB approved Offset Protocol Registry, which could include private or other government entities.

Linking to Other Cap-and-Trade Programs

The proposed regulation includes general requirements for linking to other programs. Establishing linkage with other programs will require ARB approval under the APA before allowances and/or offset credits from an external program can be used for compliance with California's regulation. The regulation does not propose linking to any specific programs at this time. Four other WCI Partner jurisdictions (New Mexico, British Columbia Ontario, and Quebec) are moving forward to initiate their cap-and-trade programs in 2012. ARB staff will evaluate those programs in 2011 and expects to make recommendations to the Board on whether linkages to these WCI programs can be in place when California's program starts in 2012.

Registration and Accounts

Under the proposed regulation, ARB would be responsible for tracking information regarding compliance instrument ownership, including transfers of ownership. The proposed regulation will require entities to register with ARB and provide information to ARB regarding ownership and submittal of compliance instruments. ARB will also require reporting of information regarding certain transactions between market participants. Some participants submitting information could be entities that do not have compliance obligations or that are not located within California. All covered entities would be required to register and create an account with ARB or designated account administrator to comply with the regulation. Voluntarily associated entities would need to register with the tracking system to hold ARB allowances or offsets.

The California Cap-and-Trade Market Tracking System (MTS) would track compliance instrument ownership, submittals and transactions. The primary goal of the MTS is to support ARB in effective implementation of the proposed regulation and to reduce the costs and administrative burden associated with long-term regulation responsibilities. The MTS will also provide information necessary for a secure, liquid, and transparent allowance market. ARB staff is working closely on development of the MTS with our partners in the WCI, since coordinated approaches to a tracking system will simplify linking the individual programs into a regional market system.

Compliance Requirements for Covered Entities

The regulation would apply an emissions threshold to determine the entities that would have a regulatory compliance obligation under the program. The inclusion threshold for each covered entity is based on the subset of GHG emissions that generate a compliance obligation for that entity. Fuel suppliers will be covered starting in 2015 based on a threshold applied to emissions associated with combustion of the fuels they deliver. Any entity whose emissions exceed the threshold in any year of a compliance period has a compliance obligation for that compliance period and the next compliance period, unless it has shut down all processes. For an entity that has shut down all processes, units, and supply operations subject to reporting, an emissions data report must be submitted for the year in which a facility or supplier's GHG-emitting processes

and operations ceased to operate, and for the first full year of non-operation following a permanent shutdown. The verification requirements in section 95103 of the Mandatory Reporting Requirements do not apply to the first full year of non-operation following a permanent shutdown.

The proposed regulation includes three-year compliance periods with the first period commencing on January 1, 2012. A compliance period is the length of time for which covered entities must submit compliance instruments equal to their verified GHG emissions. Covered entities would be required to submit a portion of the compliance instruments annually, with the remaining due following the end of the three-year compliance period. Establishing compliance periods that last for three years (instead of one year) provides some compliance flexibility.

When the covered entity surrenders the compliance instruments, ARB permanently retires them. If a covered entity does not surrender sufficient compliance instruments by the compliance date, the regulation would require the entity to cover its deficit by submitting additional allowances.

Greenhouse Gas Emission Reductions

Staff estimates that implementation of the proposed regulation would reduce GHG emissions by 18 to 27 $MMTCO_2e$ in 2020.

Documents Incorporated by Reference

(1) ASTM 6751-08, "Standard Specification for Biodeisel Fuel Blendstock (B100) for Middle Distillate Fuels" approved September 15, 2007, revised October 1, 2008;
(2) ASTM D1835-05, "Standard Specification for Liquefied Petroleum (LP) Gases;" April 1, 2005;
(3) ASTM D6751 - 09a, "Standard Specification for Biodiesel Fuel Blend Stock (B100) for Middle Distillate Fuels," approved September 15, 2007, revised October 1, 2008;
(4) ASTM D6866 – 10, "Standard Test Methods for Determining the Biobased Content of Solid, Liquid, and Gaseous Samples Using Radiocarbon Analysis," August 6, 2010 and
(5) Z'berg-Nejedly Forest Practices Act of 1973, as amended January 1, 1998.

The following documents are ARB-drafted documents that will be incorporated by reference into the cap-and-trade regulation when it is adopted. Any changes to these documents will be made available in accordance with the Administrative Procedure Act (Government Code section 11340 et seq.). The final date of these documents, if approved, will be the date of final adoption by ARB.

- Compliance Offset Protocol for Forest Projects
- Compliance Offset Protocol for Livestock Manure (Digester) Projects
- Compliance Offset Protocol for U.S. Ozone Depleting Substances Projects
- Compliance Offset Protocol for Urban Forest Projects

COMPARABLE FEDERAL REGULATIONS

This regulation is not mandated by federal law or regulations, and there are no comparable federal regulations.

AVAILABILITY OF DOCUMENTS AND AGENCY CONTACT PERSONS

The Board staff has prepared an Initial Statement of Reasons (ISOR) for the proposed regulatory action, which includes a summary of the economic and environmental impacts of the proposal. The report is entitled "Initial Statement of Reasons: Proposed Regulation to Implement the California Cap-and-Trade Program".

Copies of the ISOR and the full text of the proposed regulatory language may be accessed on ARB's website listed below, or may be obtained from the Public Information Office, Air Resources Board, 1001 I Street, Visitors and Environmental Services Center, First Floor, Sacramento, California 95814, (916) 322-2990, at least 45 days prior to the scheduled hearing on December 16, 2010.

Upon its completion, the Final Statement of Reasons (FSOR) will be available and copies may be requested from the agency contact persons identified in this notice, or may be accessed on ARB's website listed below.

Inquiries concerning the substance of the proposed regulation may be directed to Mr. Steve Cliff, Manager of the Program Evaluation Branch, at (916) 322-7194 or Ms. Brieanne Aguila, Air Pollution Specialist at (916) 324-0919.

Further, the agency representative and designated back-up contact persons to whom nonsubstantive inquiries concerning the proposed administrative action may be directed are Ms. Lori Andreoni, Manager, Board Administration & Regulatory Coordination Unit, (916) 322-4011, or Ms. Amy Whiting, Regulations Coordinator, (916) 322-6533. The Board has compiled a record for this rulemaking action, which includes all the information upon which the proposal is based. This material is available for inspection upon request to the contact persons.

This notice, the ISOR and all subsequent regulatory documents, including the FSOR, when completed, are available on ARB's website for this rulemaking at http://www.arb.ca.gov/regact/2010/capandtrade10/capandtrade10.htm

ECONOMIC ANALYSIS

Two models were used for the economic analysis of the proposed regulation. The Energy 2020 model was used to estimate the potential GHG emission reductions and the changes in investment and fuel use. The Environmental Dynamic Revenue Analysis Model (E-DRAM) was used to estimate the macroeconomic impacts of the proposed cap-and-trade regulation on the statewide economy including impacts on gross state product, personal income, and employment, based in part on outputs from Energy 2020. These analyses are presented in 2007 dollars and focus on the impacts of the proposed regulation in 2020.

Under the proposed regulation, projected economic growth would continue virtually on par with current forecasts. At likely allowance prices ($15 to $30 in the year 2020), gross state product will grow annually by about 2.3 percent instead of 2.4 percent. Impacts on long-term projected growth rates in personal income and employment are similarly small.

Investment in more energy efficient vehicles, buildings and industrial processes will help reduce fuel use between 2 and 4 percent in 2020. These reductions will help offset potential increases in the price of electricity, natural gas, and gasoline. In 2020, net expenditures (i.e., investment less fuel savings) are estimated to slightly increase by approximately 0.2 percent.

ARB's economic analysis is not meant to predict the increased growth in sectors that could result because of new opportunities created by imposing a carbon price, such as those that design or manufacture renewable technologies, or predict the creation of so called "green jobs." This analysis can therefore be considered a cautious estimate of the potential statewide impacts from the imposition of a cap-and-trade program.

The economic analysis also focuses exclusively on the economic effects in California of implementing the cap-and-trade program, and does not consider the avoided costs of inaction. The potential effects of climate change that are expected to occur in California, such as increased water scarcity, reduced crop yield, sea level rise, and increased incidence of wildfires, could cause severe economic impacts. While California has developed a Climate Adaptation Strategy to help alleviate these potential costs, the risk of potentially high economic costs from climate change in California remains real.

COSTS TO PUBLIC AGENCIES AND TO BUSINESSES AND PERSONS AFFECTED

The determinations of the Board's Executive Officer concerning the costs or savings necessarily incurred by public agencies and private persons and businesses in reasonable compliance with the proposed regulation are presented below.

Costs to State Government and Local Agencies

The Executive Officer has determined that the proposed regulatory action would create costs or savings, as defined in Government Code sections 11346.5(a)(5) and 11346.5(a)(6), to State agencies or in federal funding to the State. The proposed regulatory action would create costs and would impose a mandate on some State and local agencies, but would not create costs or impose a mandate on school districts. At least eight California public universities, several municipal utilities, two correctional facilities and the California Department of Water Resources would have a compliance obligation under the proposed regulation. These entities would be required to surrender allowances or offsets equal to the amount of their GHG emissions during the compliance period.

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

Costs to Businesses and Private Individuals

In developing this regulatory proposal, ARB staff evaluated the potential economic impacts on representative private persons or businesses. The Executive Officer has determined that representative private persons and businesses would be affected by the cost impacts from the proposed regulatory action. Representative private persons and businesses that do not exceed the emissions threshold would not be directly regulated under the proposed action, but would be indirectly affected by changes to the cost of using fossil-fuel based energy. Pursuant to Government Code section 11346.5(a)(7)(C), the Executive Officer has made an initial determination that the proposed regulatory action would not have a significant statewide adverse economic impact directly affecting businesses, and little or no impact on the ability of California businesses to compete with businesses in other states.

The proposed regulation imposes direct costs on businesses that are required to quantify and report their GHG emissions and acquire and surrender compliance instruments. Regulated businesses may face additional indirect costs due to increased energy and input prices, and some businesses might be impacted based on the compliance path they choose to meet their obligations under the proposed regulation. However, the proposed regulation would not impose sufficient direct or indirect costs to eliminate businesses in California. It is not possible to quantify the number of businesses that will be created in response to opportunities that arise as a result of the proposed regulation. However, staff believes that startups in emerging sectors such as renewable energy and biofuel production could represent significant numbers of new, small and medium sized businesses.

Therefore, in accordance with Government Code section 11346.3, the Executive Officer has determined that the proposed regulatory action would not eliminate existing businesses within the State of California, but would affect the creation of new businesses or the expansion of existing businesses currently doing business in California. The proposed regulatory action would not eliminate jobs within the State of California, but would affect the creation of jobs within California.

ARB estimates that 360 businesses or covered entities would participate in the proposed cap-and-trade program from the year of initial implementation through 2020. These businesses include: electricity generators; electricity importers; industrial facilities including cement plants, cogeneration facilities, hydrogen plants, petroleum refiners,

and general stationary combustion facilities; and many fuel providers including wholesalers of gasoline, distillate, propane, and natural gas.

In general, most small businesses in regulated sectors would not be subject to the proposed regulation because their total GHG emissions are below the GHG reporting threshold, thereby exempting them from compliance obligations under the proposed regulation. However, small businesses may experience similar cost impacts as consumers. Cost impacts on consumers would result from changes in energy prices. Households and small businesses that consume less energy (directly by reducing their consumption of energy or indirectly by utilizing goods and services that are produced using less energy) will be less affected by higher prices than those that consume more energy. Incentive programs available to small businesses and consumers will provide access to funds for investing in energy efficient technologies, which includes low interest loans, rebates and credits. Energy savings from efficiency improvements are likely to partially offset or fully mitigate the impact of any increase in electricity prices and could mean decreased energy bills. Most California businesses will likely pass along the cost increases to consumers in the form of slightly higher prices for their products or services.

ARB staff has considered whether any proposed alternatives would lessen potential adverse economic impacts on businesses. The alternatives that staff has considered are described in more detail in the Initial Statement of Reasons.

The Executive Officer has also determined, pursuant to California Code of Regulations, title 1, section 4, that the proposed regulatory action would affect small businesses.

In accordance with Government Code sections 11346.3(c) and 11346.5(a)(11), the Executive Officer has found that the reporting requirements of the proposed regulation which apply to businesses are necessary for the health, safety, and welfare of the people of the State of California.

Before taking final action on the proposed regulatory action, the Board must determine that no reasonable alternative considered by the Board, or that has otherwise been identified and brought to the attention of the Board, would be more effective in carrying out the purpose for which the action is proposed or would be as effective and less burdensome to affected private persons than the proposed action.

A detailed assessment of the economic impacts of the proposed regulatory action can be found in the Economic Impacts chapter of the Initial Statement of Reasons and in Appendix N – Supporting Documentation for the Economic Analysis.

SUBMITTAL OF COMMENTS

Interested members of the public may present comments orally or in writing at the meeting, and comments may also be submitted by postal mail or by electronic submittal before the meeting. The public comment period for this regulatory item will begin on November 1, 2010. To be considered by the Board, written comments not physically

submitted at the meeting must be submitted on or after November 1, 2010, and received **no later than 12:00 noon, December 15, 2010,** and must addressed to the following:

Postal mail: Clerk of the Board, Air Resources Board
1001 I Street, Sacramento, California 95814

Electronic submittal: http://www.arb.ca.gov/lispub/comm/bclist.php

Please note that under the California Public Records Act (Government Code section 6250 et seq.), your written and oral comments, attachments, and associated contact information (e.g., your address, phone, email, etc.) become part of the public record and can be released to the public upon request. Additionally, this information may become available via Google, Yahoo, and other search engines.

The Board requests but does not require that 20 copies of any written statement be submitted and that all written statements be filed at least 10 days prior to the hearing so that ARB staff and Board Members have time to fully consider each comment. The Board encourages members of the public to bring to the attention of staff in advance of the hearing any suggestions for modification of the proposed regulatory action.

STATUTORY AUTHORITY AND REFERENCES

This regulatory action is proposed under the authority granted in sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601 of the Health and Safety Code. This regulatory action is proposed to implement, interpret, or make specific sections 38530, 38560.5, 38564, 38565, 38570 and 39600 of the Health and Safety Code.

HEARING PROCEDURES

The public hearing will be conducted in accordance with the California Administrative Procedure Act, title 2, division 3, part 1, chapter 3.5 (commencing with section 11340) of the Government Code.

Following the public hearing, the Board may adopt the regulatory language as originally proposed, or with non substantial or grammatical modifications. The Board may also adopt the proposed regulatory language with other modifications if the text as modified is sufficiently related to the originally proposed text that the public was adequately placed on notice that the regulatory language as modified could result from the proposed regulatory action; in such event the full regulatory text, with the modifications clearly indicated, will be made available to the public, for written comment, at least 15 days before it is adopted.

The public may request a copy of the modified regulatory text from ARB's Public Information Office, Air Resources Board, 1001 I Street, Visitors and Environmental Services Center, First Floor, Sacramento, California 95814, (916) 322-2990.

SPECIAL ACCOMMODATION REQUEST

Special accommodation or language needs can be provided for any of the following:

- An interpreter to be available at the hearing;
- Documents made available in an alternate format (i.e., Braille, large print, etc.) or another language;
- A disability-related reasonable accommodation.

To request these special accommodations or language needs, please contact the Clerk of the Board at (916) 322-5594 or by facsimile at 916) 322-3928 as soon as possible, but no later than 10 business days before the scheduled Board hearing. TTY/TDD/Speech to Speech users may dial 711 for the California Relay Service.

Comodidad especial o necesidad de otro idioma puede ser proveído para alguna de las siguientes:

- Un intérprete que esté disponible en la audiencia
- Documentos disponibles en un formato alterno (por decir, sistema Braille, o en impresión grande) u otro idioma.
- Una acomodación razonable relacionados con una incapacidad.

Para solicitar estas comodidades especiales o necesidades de otro idioma, por favor llame a la oficina del Consejo al (916) 322-5594 o envíe un fax a (916) 322-3928 lo más pronto posible, pero no menos de 10 días de trabajo antes del día programado para la audiencia del Consejo. TTY/TDD/Personas que necesiten este servicio pueden marcar el 711 para el Servicio de Retransmisión de Mensajes de California.

CALIFORNIA AIR RESOURCES BOARD

James N. Goldstene
Executive Officer

Date: October 19, 2010

The energy challenge facing California is real. Every Californian needs to take immediate action to reduce energy consumption. For a list of simple ways you can reduce demand and cut your energy costs see our Website at www.arb.ca.gov.

California Environmental Protection Agency

Air Resources Board

Proposed Regulation to Implement the California Cap-and-Trade Program

PART I

Volume I

Staff Report: Initial Statement of Reasons

Release Date: October 28, 2010

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State of California

California Environmental Protection Agency
AIR RESOURCES BOARD
Office of Climate Change

STAFF REPORT: INITIAL STATEMENT OF REASONS PROPOSED REGULATION TO IMPLEMENT THE CALIFORNIA CAP-AND-TRADE PROGRAM

PART I
Volume I

Public Hearing to Consider the Proposed Regulation to Implement the California Cap-and-Trade Program

Date of Release: October 28, 2010
Scheduled for Consideration: December 16, 2010

Location:

California Air Resources Board
Byron Sher Auditorium
1001 I Street
Sacramento, California 95814

This report has been reviewed by the staff of the California Air Resources Board and approved for publication. Approval does not signify that the contents necessarily reflect the views and policies of the Air Resources Board, nor does mention of trade names or commercial products constitute endorsement or recommendation for use.

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Acknowledgments

This report was prepared with the assistance and support from many individuals within the Air Resources Board. In addition, staff would like to acknowledge the assistance and cooperation that we have received from many individuals and organizations, too numerous to list, whose contributions throughout the development process have been invaluable. Finally, staff would like to acknowledge the significant contributions from the numerous State, federal, and international governmental agencies that have provided assistance throughout the rulemaking process.

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Executive Summary

Background

Climate change is one of the most serious environmental threats facing the world today, and California is already feeling its effects. The goal of the California Global Warming Solutions Act of 2006 (AB 32, Nuñez, Chapter 488, Statutes of 2006) is to reduce greenhouse gas (GHG) emissions in a cost-effective manner. The California *Climate Change Scoping Plan* lays out a comprehensive program to scale back our greenhouse gas emissions to 1990 levels by 2020, reduce our dependence on fossil fuels, stimulate investment in clean and efficient technologies, and improve air quality and public health. Achieving these goals is best accomplished through a coordinated set of programs that employ strategies tailored to specific needs, including market-based compliance mechanisms, performance standards, technology requirements, and voluntary reductions.

The cap-and-trade program is a key element of this overall strategy. It creates a limit on the emissions from sources responsible for 85 percent of California's GHG emissions, establishes the price signal needed to drive long-term investment in cleaner fuels and more efficient use of energy, and affords covered entities flexibility to seek out and implement the lowest-cost options to reduce emissions. The cap-and-trade program is designed to work in concert with other measures, such as standards for cleaner vehicles, low-carbon fuels, renewable electricity and energy efficiency. The program will also complement and support California's existing efforts to reduce criteria and toxic air pollutants.

The cap-and-trade program and the broader Scoping Plan effort provide a model for action that can be taken at the federal level and by other states individually and through regional action. By moving forward, California is both positioning our economy to benefit as climate action is taken internationally and catalyzing action throughout the country and the world.

The California cap-and-trade program has been designed to be part of a regional trading system. The program design allows linkage with programs established by partner jurisdictions in the Western Climate Initiative (WCI) to create a regional market system. The goal of the regional program is to enhance individual jurisdictions' actions through collective action to reduce GHG emissions. On par with California, the regional cap-and-trade program would cover sources that encompass nearly 90 percent of the region's emissions.

Linking with programs established by our WCI partners has several advantages for California. The reduction of greenhouse gas emissions that can be achieved collectively by the WCI partner jurisdictions are almost double what can be achieved through a California-only program. The broad scope of a WCI-wide market will also provide greater flexibility to California businesses by offering a wider range of emissions reduction opportunities and greater market liquidity.

This report presents staff's basis and rationale for the proposed regulation to establish the California Cap-and-Trade Program. Staff developed this proposed regulation to advance California's GHG reduction goals, as required by AB 32. This regulation was developed through an extensive public process involving multiple stakeholders; local, state, and federal agencies; and the public.

Cap-and-Trade Program Objectives

In the cap-and-trade program, ARB will place a limit, or cap, on GHG emissions by issuing a limited number of tradable permits (called *allowances*) equal to the cap. Over time, the cap will steadily decline. The cap is enforced by requiring each source that operates under the cap to turn in one allowance or offset credit for every metric ton of carbon dioxide equivalent ($MTCO_2e$) that it emits.

Because these allowances are tradable, individual emitters do not have specific emission limits. By establishing a limit for the program overall rather than for individual sources, the cap-and-trade program gives sources flexibility to make the most cost-effective choices about when and how to reduce emissions. The price of allowances will be established by the marketplace based on supply and demand. Allowance prices efficiently inform consumption and investment decisions and stimulate the development of new technological solutions that can enable lower-cost reductions now and in the future. For some in the program, implementing new, low-emitting technologies may be relatively inexpensive. Those participants will buy fewer allowances or sell surplus allowances to those that face higher costs. A participant will choose to buy more allowances when the cost of an allowance is lower than the cost of reducing its emissions. By giving participants a financial incentive to control emissions and the flexibility to determine how and when to do so through the ability to trade allowances, a three-year compliance period, and other provisions such the ability to bank allowances, emissions are reduced to the capped level while minimizing the cost of emissions reductions.

In addition to allowances, a limited number of credits for emissions reductions from sources that are outside the cap coverage, called *offsets,* can be used for compliance with the program. At the end of each compliance period, covered entities are required to turn in, or surrender, enough allowances and offsets to match their emissions during this time period.

Major Provisions of the Proposed Regulation

The following elements constitute the basic components of the proposed cap-and-trade program.

Scope

The cap-and-trade program will cover the major sources of GHG emissions in the State, including refineries and power plants, industrial facilities, and transportation fuels. Starting in 2012, the program will cover electricity generation,

including imports, and large industrial sources and processes with annual GHG emissions at or above 25,000 $MTCO_2e$. The program will expand in 2015 to include fuel distributors to address emissions from combustion of transportation fuels and combustion of natural gas and propane at sources not covered in the first phase of the program.

The proposed regulation addresses emissions of carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), sulfur hexafluoride (SF_6), and nitrogen trifluoride (NF_3).

The Cap

The limit on GHG emissions—the program "cap"—determines the environmental effectiveness of the cap-and-trade program. If the cap is not set at a stringent enough level to reduce GHG emissions, the emissions-reduction goal of the program may not be met even if all sources comply with the program requirements. Staff has designed the program to be sufficiently stringent to spur GHG emissions reductions to achieve AB 32 goals.

The program cap determines the number of total allowances issued by ARB. At the start of the program, ARB will issue allowances for each year consistent with the declining level of the cap. The initial cap level in 2012 will be set at the level of emissions expected in 2012 from sources covered at the start of the program. In 2015, the program scope expands to include the distributed use of fuels, and the cap increases to include emissions from those fuels based on the level of emissions expected in 2015 from the newly covered fuels. The cap will decline to a level in 2020 designed to ensure that emissions decline over time and California achieves the AB 32 GHG emissions target in 2020.

Allowance Distribution and Trading

ARB plans to distribute allowances through a mix of direct allocation and auction. At the beginning of the program, most allowances will be distributed for free to help provide a soft start for the program. The allocation system is designed to reward those who have taken early action and have invested in energy efficiency and GHG emissions reductions and will encourage continued investment in efficiency and clean energy in the future. Because the allowances can be traded, the program provides incentives for those with the most cost-effective reduction opportunities to reduce emissions quickly.

Covered entities are not the only entities that may hold and trade allowances in the cap-and-trade program. Other entities may be eligible to participate voluntarily in the program, including financial institutions, brokers, offset developers, and those who may want to voluntarily retire allowances. An entity that holds an allowance may surrender it to comply with its obligation under the regulation, bank it for future use, sell it to another entity, or ask ARB to retire it.

Because not all allowances will be distributed for free, the program includes creation of an auction system that will allow for broad participation and minimize opportunities for manipulation. Over time, the program will transition toward a greater reliance on auctioning, which will help maximize incentives for continued investment in clean and efficient technologies and provide revenue that can be reinvested for public benefit.

Cost Containment Mechanisms

The flexibility afforded by a cap-and-trade program helps ensure that the needed GHG emissions reductions are cost-effective. Key elements of the program have been designed to optimize cost-effectiveness, including: (1) three year compliance periods, which smooth year-to-year variations in emissions levels; (2) allowance banking, which allows participants to hold allowances and use them for compliance in a later period; (3) offsets, which offer additional low-cost emissions-reduction opportunities; and (4) the establishment of an allowance reserve account, which allows covered entities access to allowances at set prices as a hedge against higher costs. A key consideration in designing these cost-containment mechanisms is to reduce compliance costs without compromising the environmental goals of the program.

Reporting

The cap-and-trade program will rely on the Mandatory Reporting Regulation (MRR) as the primary mechanism for emissions reporting. Revisions to the MRR are being proposed by ARB staff concurrently with the proposed cap-and-trade regulation. These revisions are intended to align California's reporting requirements with the federal reporting rules recently enacted by the U.S. Environmental Protection Agency (U.S. EPA), and to ensure that the information collected by those covered by the cap-and-trade program is of sufficient quality to support the program.

Additional registration and reporting requirements are established in the cap-and-trade regulation for those who hold allowances or offset credits, and for other participants in the program, including offset registries and offset project developers. These requirements have been designed to ensure transparency and effective public disclosure while also minimizing the administrative burden on those covered by the regulation and on ARB staff.

Offsets

Under the cap-and-trade program, covered entities may use a limited amount of offset credits to satisfy a portion of their compliance obligation. Offsets are tradable credits that represent verified GHG emissions reductions made in areas or sectors not covered by the cap-and-trade program. One offset credit is equal to one metric ton of GHG emissions. In addition to providing compliance flexibility, the inclusion of offsets in the program will support the development of innovative

projects and technologies from sources outside capped sectors that can play a key role in reducing emissions both inside and outside California.

Offsets must meet rigorous criteria that demonstrate that the emissions reductions are real, permanent, verifiable, enforceable, and quantifiable. To be credited as an offset, the action or project must also be in addition to what is required by law or regulation or would otherwise have occurred. Under the California cap-and-trade program, ARB will adopt specific compliance protocols for different project types, and will issue or recognize offset credits based on those adopted protocols that can be used for compliance purposes.

Offset Protocols

ARB staff reviewed four offset protocols and recommends that they be approved by the Board as part of this regulatory package: (1) the Urban Forest Projects Protocol; (2) the U.S. Ozone Depleting Substances Projects Protocol; (3) the Livestock Manure (Digester) Projects Protocol; and (4) the U.S. Forest Projects Protocol. These protocols are based on those initially developed by the Climate Action Reserve (CAR) and its predecessor, the California Climate Action Registry (CCAR). The individual protocols are reviewed in Parts II through V of this rulemaking package, and each Part includes its own staff report and recommendations. To help ensure an adequate supply of high-quality offsets, staff anticipates that additional protocols will be reviewed and brought to the Board for consideration in 2011 and beyond.

Sector-Based Offset Credits

Achieving the goal of climate stabilization will require a commitment to work at the international level to reduce GHG emissions globally. Sector-based crediting can increase participation in international efforts to control GHG emissions and address concerns about competitiveness and emissions leakage. Sectoral crediting can mobilize private and public resources, enabling the host government to reduce GHG emissions and transition toward a low-carbon economy. California has been working with strategic partners in the forest and cement sectors to explore sectoral crediting approaches to international action. The proposed regulation anticipates future inclusion of sectoral credits based on continuing work with international partners.

Compliance and Enforcement

For each compliance period, each covered entity is required to surrender a sufficient number of compliance instruments (allowances and offset credits) to cover its total GHG emissions during that compliance period. A portion of the allowances must be provided annually, with the remaining allowances due following the end of the compliance period. Once allowances and offsets are surrendered they are permanently retired by ARB.

A robust enforcement program will play a vital role in the success of the cap-and-trade program by discouraging noncompliance and by deterring and punishing fraudulent activities. It also will play a vital role in the success of the cap-and-trade program by discouraging gaming of the system and by deterring and punishing fraudulent activities. Staff designed the proposed regulation to remove any financial incentive for noncompliance by requiring that additional allowances be surrendered for excess emissions not covered by the compliance deadline. Staff will also ensure that the requirements are enforced fairly, and that the enforcement process is transparent.

Linkage to Other Greenhouse Gas Emissions Trading Systems

Linkage involves the reciprocal acceptance of compliance instruments issued by another system. The proposed regulation includes a framework for California to link its cap-and-trade program to other emissions trading systems of similar scope and rigor. Linkage can expand the coverage of the cap-and-trade program to include emissions-reduction opportunities for sources covered in another program.

Staff has designed the cap-and-trade program to allow California to link with the programs developed by WCI Partner jurisdictions that are consistent with the WCI Detailed Program Design. The proposed cap-and-trade regulation does not currently include linkage to other programs, though staff anticipates bringing recommendations to the Board in 2011 for possible linkage with the programs being developed by the four other WCI Partners that are currently working to implement programs by January, 2012: New Mexico, British Columbia, Quebec, and Ontario. Each program will undergo a case-by-case analysis by staff as part of a formal rulemaking process, and the Board will need to approve regulatory amendments reflecting the linkage with a particular program before it can take effect.

Program Monitoring

ARB will closely monitor whether, over time, the cap-and-trade program is meeting the objectives set forth in AB 32. These objectives include beneficial outcomes that should be maximized and adverse consequences that should be minimized or avoided. Much of the monitoring information ARB will need is collected as a part of normal program management, such as emissions data reports from the Mandatory Reporting Regulation, allowance price and use, or offset project annual reports. To supplement these sources, and to ensure that ARB has adequate information to identify whether the objectives are being met, ARB will require specified information from relevant expert sources, including the Offset Project Registries and Air Districts, and solicit additional information from stakeholders, including the public. Monitoring for potential emissions and economic leakage will be emphasized.

Using the results of monitoring, ARB will regularly evaluate (at a minimum once every three-year compliance period) whether the objectives identified by statute are being achieved. Periodic evaluation will be coordinated with other actions and information collection occurring at the end of compliance periods.

ARB will conduct its evaluation sufficiently in advance of the end of each compliance period to allow ARB sufficient time adjust the cap-and-trade program, if warranted, before commencement of the next compliance period. If ARB determines during its periodic review that the cap-and-trade program is not achieving the objectives as defined by AB 32, or if substantial, unanticipated adverse economic or environmental effects are identified (e.g., substantial leakage), ARB will revise the operation and/or design of the program accordingly.

Evaluation of the Regulation

Staff analyzed four alternatives to the proposed cap-and-trade regulation: (1) a "no project" alternative; (2) additional source-specific regulations; (3) a carbon fee; and (4) linking California's cap-and-trade program to a future federal cap-and-trade program. In evaluating these alternatives, ARB staff found that none were as or more effective than the implementation of a cap-and-trade program in carrying out the goals of AB 32. In addition, staff analyzed a number of specific alternatives to the design of the cap-and-trade program. In recommending the specific design included in this proposal, staff balanced the need to maintain the environmental integrity of the program, to retain a level of flexibility to help ensure cost-effectiveness, and to consider the potential for co-benefits.

This proposal has been evaluated for possible environmental impacts consistent with the requirements of the California Environmental Quality Act (CEQA). The environmental analysis also identifies potential environmental benefits associated with the proposed cap-and-trade program. The analysis identified potentially significant impacts related to air quality and to activities that disturb the ground, such as construction projects or site preparation for tree planting to establish offset credits. Based on the information available, such impacts are highly unlikely, but are nonetheless possible. ARB's adaptive management program will include review of required reports and solicitation of comments from the public and stakeholders, including in-state and out-of state resource management agencies with jurisdiction over the forestry-related offset projects.

Emissions Assessment

Air pollutant emissions that contribute to ozone and particulate matter pollution (i.e., criteria pollutants) and toxic air pollutants are "co-pollutants" often associated with GHG emissions from combustion processes. AB 32 requires ARB to consider the co-pollutant benefits of reducing GHGs. California's air pollution control programs for criteria and toxic pollutants will continue to significantly reduce emissions and health risk into the future. Technology improvements and enhanced energy efficiency resulting from the cap-and-trade

program can further reduce these co-pollutants, providing public health benefits on both a regional and local basis in addition to the benefits of reducing GHG emissions.

For market based-regulations like the cap-and-trade program, AB 32 requires ARB to consider the potential for direct, indirect, and cumulative emissions impacts, including localized impacts. Staff evaluated potential emissions impacts statewide and in four community case studies. The assessment focuses on the potential criteria and toxic pollutant emissions impacts from the industrial sources covered by the program. However, the assessment does not include criteria pollutant and toxic emissions reductions that the cap-and-trade program is expected to provide from transportation fuels and commercial and residential gas use, in addition to those likely to occur at industrial facilities.

Due to the inherent flexibility of the cap-and-trade regulation, as well as the overlay of other complementary greenhouse gas reduction measures, it is difficult to predict the decisions that individual facilities may make in any given community. However, based on the available data, current law and policies that control industrial sources of air pollution, and expected compliance responses, ARB believes that emissions increases at the statewide, regional, or local level due to the regulation are not likely. ARB seeks to ensure that the cap-and-trade program, as it operates over time, avoids and minimizes all instances of localized air quality impacts. ARB will use information collected through the mandatory reporting regulation, the cap-and-trade regulation, the industrial efficiency audit, and other sources to evaluate how facilities are complying with the cap-and-trade regulation. ARB will also solicit information from local air districts regarding permit modifications and new permit applications for covered sources. ARB will evaluate data from a variety of sources to determine whether there are any disproportionate impacts to low-income communities or any increases in the emissions of toxic air contaminants or criteria air pollutants resulting from the cap-and-trade program. If unanticipated adverse localized air quality impacts are identified during this periodic review, ARB is committed to promptly developing and implementing appropriate responses.

Economic Analysis

The cap-and-trade program is expected to result in increased investment in efficient buildings and technologies and in advanced fuels. At expected allowance prices ($15 and $30 per metric ton in 2020), these investments would reduce fuel use by 2 to 4 percent in 2020, while economic growth between 2007 and 2020 continues at a rate of 2.3 percent, virtually on par with the projected rate of 2.4 percent. Implementation of the program will, however, shift investment and growth within the overall economy toward those sectors driven by the production of cleaner and more efficient technologies.

Implementing the cap-and-trade program can also help mitigate the economic consequences of continued reliance on fossil fuels. Experience in recent

decades, such as the spike in world oil prices in the summer of 2008, has illustrated the economic costs of volatile energy prices on California's economy. While this report does not attempt to quantify the insurance benefits of reduced dependence on fossil fuels in the face of continued volatility of world energy prices, it does show that California can significantly reduce its dependence on these fuels and, therefore, its vulnerability to future price spikes.

This economic analysis focuses exclusively on the economic effects in California of implementing the cap-and-trade program, and does not consider the avoided costs of inaction. The potential effects of climate change on California that are expected to occur, such as increased water scarcity, reduced crop yield, sea level rise, and increased incidence of wildfires, could cause severe economic impacts. While California has developed a Climate Adaptation Strategy to help alleviate these potential costs, the risk of potentially high economic costs from climate change in California remains real.

Requirements of AB 32

AB 32 calls on ARB to adopt regulations by January 1, 2011, to implement measures to "achieve the maximum technologically feasible and cost-effective reductions in greenhouse gas emissions." AB 32 requires that the reductions be real, permanent, quantifiable, verifiable, and enforceable. AB 32 includes specific standards that apply to regulations that use market-based compliance mechanisms, such as the cap-and-trade program.

Furthermore, AB 32 calls for the Board to "ensure that the greenhouse gas emissions-reduction rules, regulations, programs, mechanisms, and incentives under its jurisdiction, where applicable and to the extent feasible, direct public and private investment toward the most disadvantaged communities in California and provide an opportunity for small business, schools, affordable housing associations, and other community institutions to participate in and benefit from statewide efforts to reduce greenhouse gas emissions."

The proposed regulation was developed in accordance with the requirements of AB.32 and the Staff Report presents supporting details. The following provides a brief response to several of the key AB 32 requirements that have received particular attention during the cap-and-trade rulemaking.

Several AB 32 requirements relate to the potential economic effects of GHG regulations, including direction to minimize costs and maximize the total benefits, and to minimize leakage. Staff has designed the proposed cap-and-trade program, including the allowance allocation system, to minimize the cost of implementation and compliance and to maximize the overall benefits. The allowance allocation system is equitable within and across sectors of the California economy, and its primary reliance on efficiency benchmarks and auction encourages early action to reduce emissions. In addition, the ability to

bank allowances for future use provides an incentive for early action to reduce emissions.

By ensuring that most GHG emissions in California are covered by the program, and that incentives are in place to ensure that the most cost-effective reductions are made, the program design shares the emissions-reduction burden equitably.

Other AB 32 requirements relate to maximizing co-benefits, avoiding disproportionate impacts, considering the potential for emissions impacts, and avoiding emissions increases. Staff has evaluated both the health and economic effects of the proposed program to ensure to the extent feasible that no disproportionate negative impact will occur. The overall health and environmental effects of the regulation are expected to be positive, and the program has been designed to minimize the economic costs of the program, which will minimize the effects on low-income communities.

AB 32 also calls for providing appropriate credit for early voluntary reductions and encouraging early action. ARB staff has recommended a system for distributing allowances in the industrial sector that will primarily rely on the relative efficiency of facilities for any free allocation. This approach rewards those who have already invested in emissions reductions. In addition, a portion of the allowances will be auctioned, and those who have taken early action will be less reliant on purchasing allowances at auction. This allowance allocation system provides appropriate credit for those who have taken steps to voluntarily reduce their emissions before the start of the cap-and-trade program. In addition, the ability to bank allowances for future use provides an incentive for early action to reduce emissions. The regulation would also allow existing offset credits generated under early versions of any offset protocols that the Board adopts to be used for compliance as early action offset credits.

Public Process for Cap-and-Trade Regulation Development

ARB staff developed this proposed cap-and-trade regulation through an extensive public process. In 2008, staff discussed the general framework for a cap-and-trade program as part of the development of the Scoping Plan. The Board included the cap-and-trade program as one of the central measures in the Scoping Plan.

Following the Board's adoption of the Scoping Plan, staff held more than 30 public workshops in 2009 and 2010 devoted to developing the cap-and-trade program design in more detail. These meetings allowed stakeholders and the public to discuss and share ideas on the appropriate design of the cap-and-trade program. Staff reviewed hundreds of public comments received from stakeholders and the general public from these workshops. Staff considered these comments in crafting the design of the proposed cap-and-trade regulation.

In November 2009, staff released a conceptual framework for the cap-and-trade program called the Preliminary Draft Regulation (PDR). The PDR combined preliminary regulatory language on the cap-and-trade process and structure, along with narrative text that described significant issues for which specific regulatory language had not yet been developed. In some cases, most notably the allocation sections, placeholders marked where specific language still needed to be developed. Staff released the PDR to maximize the opportunity for public comment and to advance the public dialogue on the proposed structure and content of this key Scoping Plan measure. In response to the PDR, staff received numerous written comments.

Staff also provided regular updates to the Board on the development of the cap-and-trade program, including on allocation and offsets. Staff has also met with individuals, businesses, government representatives, scholars, experts, non-governmental organizations, and general members of the public on a regular basis during the development of this regulation.

Recommendation

Staff recommends that the Board adopt the proposed cap-and-trade regulation. The program is expected to reduce GHG emissions between 18 and 27 $MMTCO_2e$ in 2020, and the flexibility included in the program will ensure that these reductions are cost-effective. By establishing an overall cap on emissions from the major sources in California, the program will also play a critical role in ensuring that the AB 32 emissions target is met by 2020.

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I BACKGROUND AND INTRODUCTION

This Staff Report presents the California Air Resources Board (ARB or Board) staff's basis and rationale for the proposed regulation for the California Cap-and-Trade Program. The cap-and-trade regulation is designed to cost-effectively reduce emissions of greenhouse gases (GHG) by establishing a cap covering approximately 85 percent of the State's GHG emissions and drive investment in cleaner and more efficient technologies to power California's economy. Staff developed this proposed regulation to advance California's GHG reduction goals as required by the California Global Warming Solutions Act of 2006 (AB 32) (AB 32, Nunez, Statutes of 2006, Chapter 488). This introduction describes the structure of the Staff Report and provides background on California's *Climate Change Scoping Plan,*[1] the Western Climate Initiative, and the public process used to develop the cap-and-trade program.

This Staff Report, including the attached appendices, represents the Initial Statement of Reasons (ISOR) for Proposed Rulemaking required by the California Administrative Procedure Act.[2]

Part I of the Staff Report is divided into the following chapters:

- Chapter I. Background and Introduction – Provides background on California's *Climate Change Scoping Plan,* the Western Climate Initiative, and the public process used to develop the cap-and-trade program.

- Chapter II. General Summary of the Proposed Regulation – Discussion of selected design elements of the California Cap-and-Trade Program.

- Chapter III. Overview of the Compliance Offsets Program – Discussion of the design of the compliance offset program including: offset credits issued by ARB, early action offset credits, and sector-based offset credits, including Reducing Emissions from Deforestation and Degradation (REDD).

- Chapter IV. Analysis of Alternatives to the Proposed Regulation – Describes alternatives that were considered for the California Cap-and-Trade Program, and why the alternatives are less effective.

- Chapter V. Compliance Pathway Scenarios – Discusses scenarios and emissions-reduction opportunities that could be achieved by sources covered by the cap-and-trade program.

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[1] Climate Change Scoping Plan: A Framework for Change. Air Resources Board, December 2008. Found at: http://www.arb.ca.gov/cc/scopingplan/scopingplan.htm.

[2] The Administrative Procedure Act, Government Code section 11340 et seq.

- Chapter VI. Environmental Impacts of the Proposed Regulation – Describes potential impacts the proposed regulation may have on the environment, including potential impacts from project-specific activities.

- Chapter VII. Co-Pollutant Emissions Assessment – Describes the public health impacts of the proposed regulation.

- Chapter VIII. Economic Impacts of the Proposed Regulation – Describes the economic impacts of the regulation.

- Chapter IX. Summary and Rationale for the Proposed Regulation – Describes the rationale for developing the rule provisions of the proposed regulation.

- Chapter X. References – Provides a list of references used for development of the Staff Report.

- Appendices include the proposed cap-and-trade regulation and technical appendices, including: cap setting; compliance pathways analysis; allowance price containment; allocation; leakage analysis; and co-pollutant emissions.. They also include the Functional Equivalent Document that provides the environmental assessment required under the California Environmental Quality Act (CEQA) and other documents that serve as supporting documentation for the design and development of the program.

- Parts II through V provide Compliance Offset Protocols and related staff reports.

A. Background

Climate change poses a serious threat to the economic well-being, public health, natural resources, and environment of California. Global warming is projected to have detrimental effects on some of California's largest industries (including agriculture and tourism), increase the strain on electricity supplies, and contribute to unhealthy air.[3] National and international actions are necessary to fully address the issue of global warming; therefore, California's efforts alone will not solve the problem. Action taken by California to reduce emissions of GHGs will encourage other states, the federal government, and other countries to act. By exercising a leadership role, California will also position its economy, technology

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[3] Our Changing Climate – Assessing the Risks to California. California Energy Commission. Publication # CEC-500-2006-077, July 2006. Found at: http://www.energy.ca.gov/2006publications/CEC-500-2006-077/CEC-500-2006-077.PDF.

centers, academic and financial institutions, and businesses to benefit from national and international efforts to reduce emissions of greenhouse gases.

The Legislature passed and the Governor signed AB 32 to exercise this leadership role. AB 32 directed ARB to prepare a Scoping Plan outlining the State's strategy to achieve the GHG reduction limit established in the law. The reduction measures to meet the 2020 target are to become operative by 2012 (Health and Safety Code (HSC) §38562(c)).

AB 32 includes several specific requirements for ARB including:

- Identify the statewide level of greenhouse gas emissions in 1990 to serve as the emissions limit to be achieved by 2020 (HSC §38550).
- Adopt a regulation requiring the mandatory reporting of greenhouse gas emissions (HSC §38530).
- Identify and adopt regulations for Discrete Early Actions that could be enforceable on or before January 1, 2010 (HSC §38560.5).
- Prepare and approve a Scoping Plan that identifies direct emissions-reduction measures, alternative compliance mechanisms, market-based compliance mechanisms, and potential monetary and non-monetary incentives to achieve the maximum technologically feasible and cost-effective reductions in greenhouse gas emissions by 2020 (HSC §38561).
- Ensure that early voluntary reductions receive appropriate credit in the implementation of AB 32 (HSC §38562(b)(3)).
- Convene an Environmental Justice Advisory Committee (EJAC) to advise the Board in developing the Scoping Plan and any other pertinent matter in implementing AB 32 (HSC §38591).
- Appoint an Economic and Technology Advancement Advisory Committee (ETAAC) to provide recommendations for technologies, research, and greenhouse gas emissions-reduction measures (HSC §38591).

AB 32 also includes a number of specific requirements that ARB must fulfill, to the extent feasible and in furtherance of achieving the statewide GHG emissions limit, before adopting regulations that include market-based mechanisms:

- Consider the potential for direct, indirect, and cumulative emissions impacts, including localized impacts in communities that are already adversely affected by air pollution (HSC §38570(b)(1)).

- Design any market-based compliance mechanism to prevent any increase in the emissions of toxic air contaminants or criteria air pollutants (HSC §38570(b)(2)).

- Maximize additional environmental and economic benefits for California, as appropriate (HSC §38570(b)(3)).

B. California's Climate Change Scoping Plan

The California *Climate Change Scoping Plan* was developed by ARB in coordination with the Climate Action Team and approved by the Board. The Plan lays out a comprehensive program to scale back our GHG emissions to 1990 levels by 2020, reduce our dependence on fossil fuels, stimulate investment in clean and efficient technologies, and improve public health. Effectively achieving these goals is best accomplished through a mix of complementary strategies that combine market-based compliance mechanisms, direct regulations, and voluntary actions.

The cap-and-trade program is a key element of this overall strategy. It establishes an overall limit on the emissions from sources responsible for 85 percent of California's GHG emissions, establishes the price signal needed to drive long-term investment in cleaner and more efficient types of fuels and energy sources, and affords covered entities flexibility to seek out and implement the most cost-effective options to reduce emissions.

As detailed in the Scoping Plan, the cap-and-trade program is designed to work in concert with a number of other complementary measures, such as standards for cleaner vehicles, low-carbon fuels, renewable electricity, and energy efficiency. The rationale for combining a cap-and-trade program with complementary measures was outlined by the Market Advisory Committee, which noted the following in its recommendations to the ARB:

> Before setting out the key design elements of a cap-and-trade program it is important to explain how the proposed emissions trading approach relates to other policy measures. The following considerations seem especially relevant:
>
> - The emissions trading program puts a cap on the total emissions generated by facilities covered under the system. Because a certain number of emissions allowances are put in circulation in each compliance period, this approach provides a measure of certainty about the total quantity of emissions that will be released from entities covered under the program.
>
> - The market price of emissions allowances yields an enduring price signal for GHG emissions across the economy. This price signal provides incentives for the market to find new ways to reduce emissions.

- By itself, a cap-and-trade program alone will not deliver the most efficient mitigation outcome for the State. There is a strong economic and public policy basis for other policies that can accompany an emissions trading system.[4]

C. Western Climate Initiative

The Western Climate Initiative (WCI) is a cooperative effort of seven U.S. states and four Canadian provinces (the "partners") that are collaborating to identify, evaluate, and implement policies to reduce GHG emissions, including the design and implementation of a regional cap-and-trade program. The WCI began in February 2007 with the governors of Arizona, California, New Mexico, Oregon, and Washington, who have since been joined by the premiers of British Columbia, Manitoba, Ontario, and Quebec, and the governors of Montana and Utah. Participation in the WCI reflects each partner's strong commitment to identifying, evaluating, and implementing collective and cooperative actions to address climate change.

1. The WCI Regional Cap-and-Trade Program

The central component of the WCI partner jurisdictions' comprehensive strategy is a flexible, market-based, regional cap-and-trade program that encourages the most cost-effective, reliable alternatives to reduce GHG emissions. The California cap-and-trade program intends to link to the programs established by other regional partner jurisdictions in the WCI to create a regional market system to collectively reduce GHG emissions. Similar to the California target, the regional program would cover sources that encompass about 90 percent of the region's emissions, and when fully implemented, would nearly double the reductions of a California-only program.

The WCI regional cap-and-trade program will consist of each individual jurisdictions' cap-and-trade program implemented through state and provincial regulations. Each partner jurisdiction implementing a cap-and-trade program will issue emission allowances to meet its jurisdiction-specific emissions goal. A regional allowance market is created by the partner jurisdictions accepting each other's allowances for compliance. The allowances can be sold between and among covered entities in linked jurisdictions, as well as by third parties.

Five WCI partner jurisdictions are currently working toward starting their programs in 2012: California, New Mexico, British Columbia, Ontario, and Quebec. These partners represent approximately two-thirds of the total

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[4] Market Advisory Committee. *Recommendations for Designing a Greenhouse Gas Cap-and-Trade System for California.* June 30, 2007. p. 19. Found at: http://www.climatechange.ca.gov/publications/market_advisory_committee/2007-06-29_MAC_FINAL_REPORT.PDF.

emissions in the WCI jurisdictions—a critical mass and a robust market for achieving significant GHG emissions reductions.

2. WCI Cap-and-Trade Program Design

On July 27, 2010, the partner jurisdictions of the WCI released a comprehensive strategy designed to reduce GHG emissions, stimulate development of clean-energy technologies, create green jobs, increase energy security and independence, and protect public health. The Design for the WCI Regional Program[5] is the culmination of two years of work by the partners.

The WCI program design recognizes that variations in jurisdictional authority, regulatory procedures, and administrative requirements will result in different approaches to implementation of a cap-and-trade program. Between now and the planned program start date of January 2012, the WCI partner jurisdictions will take the steps necessary to make regional trading operational. They will also expand their efforts to develop and implement other core policies and programs, such as California's complementary measures, to increase energy efficiency and fuel diversification to reduce GHG emissions. The WCI partner jurisdictions will continue to consult with stakeholders on the development of this regional effort.

D. Public Process for Regulation Development

Staff developed the regulatory proposal for the California cap-and-trade program with significant public input. The public process for the cap-and-trade program began in 2008 with the development of the Scoping Plan. At that time, staff discussed the general cap-and-trade program framework through numerous workshops and public consultations. The final Board-adopted Scoping Plan included the cap-and-trade program as a key element.

Building on the Scoping Plan structure for a cap-and-trade program, staff held more than 30 public workshops in 2009 and 2010. Staff used these workshops to discuss options for the program design with stakeholders who shared their ideas on the design of the program. Staff received and reviewed hundreds of public comments from stakeholders as part of the workshop process. Staff also gave numerous updates to the Board and met regularly with individual stakeholders to discuss their individual concerns and recommendations. As part of the regional effort, staff also participated in the WCI public process to understand the concerns of regional stakeholders.

ARB also received input and advice from the Market Advisory Committee and two advisory committees created under AB 32: the Economic and Technology

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[5] *Design for the WCI Regional Program.* Western Climate Initiative, July 27, 2010. Found at: http://westernclimateinitiative.org/component/remository/general/program-design/Design-for-the-WCI-Regional-Program/.

Advancement Advisory Committee (ETAAC) and the Environmental Justice Advisory Committee (EJAC). In addition, in May 2009, Cal/EPA Secretary Adams and ARB Chairman Nichols created the Economic and Allocation Advisory Committee (EAAC) to assist ARB in developing the cap-and-trade program. This panel of economic, financial, and policy experts was asked to evaluate various cap-and-trade allocation strategies and to review staff's Updated Economic Analysis of California's Climate Change Scoping Plan.[6] Staff has carefully considered the input from these committees during the program's development.

In November 2009, staff released a conceptual framework for the cap-and-trade program called the *Preliminary Draft Regulation (PDR)*. Staff held a workshop on the draft in December 2009. The PDR contained preliminary regulatory language on the cap-and-trade process and structure, accompanied by narrative text that described significant issues for which specific regulatory language had not yet been developed. The primary purpose of releasing the PDR was to maximize the opportunity for public comment and to advance the public dialogue on the proposed structure and content of this key Scoping Plan measure. In response to the PDR, staff received over 130 written comments that were considered in the development of this staff proposal.

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[6] *Updated Economic Analysis of California's Climate Change Scoping Plan: Staff Report to the Air Resources Board.* March 24, 2010. http://www.arb.ca.gov/cc/scopingplan/economics-sp/updated-analysis/updated_sp_analysis.pdf (accessed September 23, 2010).

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II GENERAL SUMMARY OF PROPOSED REGULATION

A. General Overview of Proposed Cap-and-Trade Program

Under AB 32, California must reduce greenhouse gas (GHG) emissions to 1990 levels by 2020. Cap-and-trade is one of the key measures that California will employ to reduce emissions and drive long-term investment in cleaner and more efficient technologies to power the State's economy. As proposed here, the cap-and-trade program would establish a firm cap covering about 85 percent of the State's GHG emissions and allow trading of allowances to ensure cost-effective emissions reductions.

The cap-and-trade program will cover the major sources of GHG emissions in the State, including refineries and power plants, industrial facilities, and transportation fuels. The program will impose an enforceable emissions cap beginning in 2012 that will steadily decline over time. The State will distribute allowances, which are tradable permits, equal to the cap. Sources under the cap will need to turn in allowances equal to their emissions at the end of each compliance period. Sources that aggressively reduce their emissions can trade their surplus allowances to firms who find it more expensive to reduce their emissions. In the early stage of the program, most allowances will be distributed for free to provide a smooth transition into the program, allowing those covered by the program to focus on investing in emissions reductions and cleaner technologies, and limiting any concerns about competitiveness and emissions leakage.

Under the cap-and-trade program, offset credits can be used by covered entities to meet a portion of their compliance obligation. An *offset* is a credit that represents a reduction of greenhouse gases resulting from an activity that can be measured, quantified, and verified. Each offset credit represents a specific quantity of emissions reductions from a source not directly covered by the cap-and-trade program.

Implementation and enforcement of the cap-and-trade program will be key in ensuring that California meets its AB 32 goals. The proposed regulation includes strict rules for reporting emissions and trades, with substantial penalties for violations. Transparency in the trading process is important to avoid market volatility and manipulation.

This section provides a high-level overview of the elements of the proposed cap-and-trade program. Each design element is discussed in more detail later in this Chapter.

1. Cap-and-Trade

In the proposed program, a limit, or cap, is put on the amount of GHGs that can be emitted by all covered sectors. The total number of allowances created is equal to the cap set for cumulative emissions from all the covered sectors. In

addition to allowances, credits for a limited amount of emissions reductions from sources that are outside the cap coverage, called *offsets*, will be allowed for compliance. The use of offsets will allow emissions in the capped sectors to slightly exceed the allowances issued, though these additional emissions from capped sectors will be matched by emissions reductions that result from offset projects. The term *compliance instrument* covers both allowances and offsets. These compliance instruments may be traded among entities. At the end of each three-year *compliance period*,[7] covered entities are required to turn in, or *surrender*, enough compliance instruments to match their emissions during this time period. Each allowance equals one metric ton of carbon dioxide equivalent. Since the program includes some GHGs (e.g., methane) that are more effective at trapping heat than carbon dioxide is, all emissions are measured in units relative to the heat-trapping potential of carbon dioxide, or CO_2e; the "e" standing for "equivalent."

The cap-and-trade program puts a price on emitting greenhouse gases. This price provides incentives for GHG emissions reductions and innovation. It can stimulate reductions for all covered sectors without requiring individual regulations for all GHG emissions. Pricing GHGs in this way ultimately creates a market for finding the most cost-effective emissions reductions. Providing entities with the flexibility to find the most cost-effective reductions lowers the program's overall cost. Creating a market provides more flexibility than direct regulation can, and it also provides incentives that can spur local investment and the use of green technologies.

2. Fundamental Elements of the Cap-and-Trade Program

The following elements constitute the basic components of the proposed cap-and-trade program.

a. Scope

The proposed regulation phases sectors into the program. Under this phased approach, entities in the following sectors will be covered in the program according to the following timelines:

Starting in 2012 (first compliance period):

- Electricity generation, including electricity imported from outside California.
- Large industrial sources with GHG emissions at or above 25,000 metric tons of carbon dioxide equivalent ($MTCO_2e$).

[7] A *compliance period* is the length of time for which covered entities must submit compliance instruments equal to their verified emissions.

Starting in 2015 (the second compliance period), the program expands to include fuel distributors in order to cover emissions associated with:

- Combustion of gasoline, diesel, natural gas, and propane from sources with emissions below 25,000 $MTCO_2e$, including all commercial, residential, and small industrial sources.

- Fuels used for transportation.

All sectors listed above will be covered through 2020.

b. The Cap

The limit on GHG emissions—the *cap*—is a critical part of the cap-and-trade program design because it determines the number of total allowances ARB issues. The cap is set in the proposed regulation and consists of annual cap numbers, also referred to as "budgets." Staff included annual numbers through 2020 in the proposed regulation to allow entities that have a compliance obligation to know how many allowances will be available from 2012 through 2020.

The initial cap level in 2012 will be set at the level of emissions expected from covered sources for that year—at 165.8 million $MTCO_2e$ ($MMTCO_2e$). The cap then declines starting in 2013 until 2015. In 2015 the cap will be expanded to include GHG emissions from fuel suppliers. This expansion is based on the level of GHG emissions expected from the covered fuels for the year 2015, resulting in a cap for 2015 of 394.5 $MMTCO_2e$. The cap will then continue to decline from 2015 to 2020.

The level of the cap is critical to the environmental effectiveness of the cap-and-trade program. If the cap is not set at a stringent enough level to drive GHG emissions-reduction activities, the environmental goals of the program may not be met even if all sources comply with program requirements. Staff has designed the program to be sufficiently stringent to spur GHG emissions reductions to achieve AB 32 goals. Staff has set the cap for 2020 at 334 $MMTCO_2e$, which is designed to allow California to achieve the AB 32 target in 2020.

c. Allowances

As discussed previously, an allowance is equal to one metric ton of CO_2e. ARB will issue a total of approximately 2.7 billion allowances for the cap-and-trade program through the year 2020. Annual allowance budgets for calendar years 2012–2020 are established in the proposed regulation, so that the total number of allowances issued in each year through 2020 are known. At the end of a compliance period, each covered entity is required to surrender allowances (and if it elects, a limited amount of offsets) equal to its total GHG emissions during that compliance period. ARB will also require entities to surrender compliance instruments to match a portion of their reported emissions each year during the

three-year compliance period to reduce the risk of noncompliance at the end of the three-year period. When compliance instruments are surrendered, ARB will permanently retire them.

Covered entities are not the only entities that may hold and trade allowances in the program. Entities in covered sectors with emissions less than 25,000 $MTCO_2e$ may voluntarily elect to become covered entities. Other non-covered entities may be eligible to participate voluntarily. Some examples of these non-covered entities include financial institutions or brokers, offset developers, and those who may want to obtain and voluntarily retire allowances. Once an entity holds an allowance, it can: (1) surrender it to comply with an obligation under the regulation: (2) bank it for future use; (3) trade it to another entity; or (4) ask ARB to retire it.

Staff proposes to create a gradual transition into the program through the design of the allocation system. ARB will rely primarily on free allocation at the start of the program to minimize near-term costs to California consumers and businesses and to minimize emissions leakage. The allocation design will reward those who have invested in energy efficiency and GHG emissions reductions, and will encourage continued investment in clean and efficient technologies in the future.

The outset of the program will include a small direct auction that includes a consignment feature for allowances allocated to electricity distribution utilities. Staff designed an auction program that will allow for broad participation by diverse market players and minimize the chances for manipulation. The auction is set up in a way to ensure that allowances go to those market participants that place the highest value on them.

d. Cost Containment Mechanisms

The proposed cap-and-trade program includes a number of mechanisms designed to minimize the costs of reducing GHGs without compromising the environmental integrity of the program. Some of the mechanisms that staff proposes in the cap-and-trade regulation are three-year compliance periods, banking, offsets, the Allowance Price Containment Reserve, and linkage to other trading systems.

i. Three-Year Compliance Period

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

ii. Banking

In a cap-and-trade program, banking allows participants to hold spare allowances and use them for compliance in a later period. The ability to bank allowances

provides an incentive for covered entities to make early reductions since the declining cap could push allowance prices higher over time. Staff proposes to allow banking of allowances without restriction.

iii. Offset Credits

Under the proposed program, covered entities may use offset credits to satisfy a portion of their compliance obligation. In addition to providing compliance flexibility, the inclusion of offsets in the program will support the development of innovative projects and technologies from sources outside capped sectors that can play a key role in reducing emissions both inside and outside California.

Offsets must meet rigorous criteria that demonstrate that the emissions reductions are real, permanent, verifiable, enforceable, and quantifiable. To be credited as an offset, the action or project must also be additional to what is required by law or regulation or would otherwise have occurred. Under the program, ARB will issue or recognize an offset credit that could be used by a covered entity instead of turning in an allowance for the equivalent amount of CO_2e emitted.

The proposed program imposes a limit on the amount of offsets that an individual covered entity can use for compliance. Allowing a limited number of offsets into the program provides benefits and ensures that some GHG emissions reductions occur within the sectors covered by the cap-and-trade program. The proposed program includes provisions that would allow a maximum of 232 $MMTCO_2e$ of offsets through the year 2020. This limit will be enforced through a limit on the use of offsets by an individual entity equal to eight percent of its compliance obligation. Combined with the Allowance Price Containment Reserve, this limit ensures that a majority of reductions from the program come from sources covered by the program at expected allowance prices, while use of the Reserve will relax that constraint if prices rise.

iv. Allowance Price Containment Reserve

Staff proposes to establish an Allowance Price Containment Reserve (the *Reserve*). The Reserve is an account that is filled with a specified number of allowances removed from the overall cap at the beginning of the program. Covered entities may purchase reserve allowances at specified prices during direct quarterly sales. Covered entities gain flexibility through access to the Reserve if prices are high or entities expect prices to be high in the future. Staff proposes that the Reserve be filled with 123.5 million allowances out of the total of approximately 2.7 billion issued for the years 2012 to 2020.

To ensure that allowance prices do not get too low to stimulate emissions reductions, the proposed regulation establishes a price floor at the auction of $10 per metric ton. Allowances that are unsold at auction will be added to the Reserve. This may happen if not all allowances are sold at the price floor of $10.

v. Linkage to Other Greenhouse Gas Emissions Trading Systems

Linkage is the reciprocal acceptance of compliance instruments issued by another system. California could decide to link its cap-and-trade program to other emissions trading systems of similar scope and rigor, and has been working with our WCI partners to create the framework for a regional system of linked programs. Linkage can expand the coverage of the cap-and-trade program to include emissions-reduction opportunities for sources covered in another program. The proposed regulation establishes a framework for linkage. Each program considered for linkage would by subject to Board action, and will undergo a case-by-case analysis by staff as part of a formal rulemaking process.

Although the regulation does not propose to link to any programs at this time, four programs are candidates for linkage before the 2012 start date. Currently four other WCI partners—New Mexico, British Columbia, Quebec, and Ontario—are working to implement cap-and-trade programs consistent with the Design for the WCI Regional Program by January 2012. Linking to WCI partners has several advantages for California. The reduction of GHG emissions that can be achieved collectively by the WCI partner jurisdictions are approximately double what can be achieved through a California-only program. The broad scope of a WCI-wide market will provide additional opportunities for reduction of emissions, therefore, providing greater market liquidity and more stable carbon prices within the program.

California and other WCI partners have also been participating in the Three Regions collaborative process with representatives from the jurisdictions in the Regional Greenhouse Gas Initiative and the Midwestern GHG Reduction Accord. The Three Regions have joined in a cooperative effort to share experiences in the design and implementation of regional cap-and-trade programs, inform federal decision making on climate change policy, and explore the potential for further collaboration among the three regional programs in the future.

e. Program Implementation

Assuming the design of the cap-and-trade program is approved by the Board, significant work will be needed to implement the regulation. Two primary areas that will require attention are finalizing the details of the allocation system for allowances, and designing and implementing a market tracking system. ARB staff is working closely on both efforts with our partners in the WCI, since coordinated approaches to allocation and the tracking system will simplify linking the individual programs into a regional market system. ARB staff believes that it is important for California to start its program in conjunction with our WCI partners.

f. Compliance and Enforcement

A robust enforcement program will play a vital role in the success of the cap-and-trade program by discouraging gaming of the system and deterring and punishing fraudulent activities. One allowance is needed to cover one metric ton

of a covered entity's emissions, if they are turned in by the compliance deadline. If an entity does not meet the compliance deadline, it will need to surrender additional allowances. Staff designed the proposed regulation to remove, to the extent possible, financial incentives for noncompliance and to make sure that every metric ton of GHG emitted is covered by a valid compliance instrument.

To develop the enforcement program for cap-and-trade, staff consulted with legal and enforcement staffs from state and federal agencies to gain insight in this area. These agencies included the California Environmental Protection Agency, California Attorney General's Office, the California Energy Commission, the California Public Utilities Commission, the California Department of Water Resources, United States Department of Justice, the United States Securities and Exchange Commission, and the United States Commodities and Futures Trading Commission. In addition, staff consulted with academic institutions including UC Berkeley's Center for Law, Energy, and the Environment and legal scholars from other universities.

B. Reporting Requirements

The Mandatory Greenhouse Gas (GHG) Reporting Regulation (MRR) appears in Subchapter 10, Article 2, sections 95100-95199, title 17, California Code of Regulations. This regulation is a set of rules that establishes who must report GHG emissions to ARB and sets forth the requirements for monitoring, calculating, reporting, and verifying those emissions. The MRR established reporting requirements for electricity and the largest stationary sources of GHG emissions in California. Changes are needed to the existing MRR because the cap-and-trade program covers more than large stationary sources and includes electricity importers, transportation fuels, and smaller sources of fuel combustion by regulating the providers of these fuels. These changes will also ensure that the reported data are rigorous enough to support a trading program. These amendments and the MRR Initial Statement of Reasons will be considered by the Board in a separate rulemaking at the same time as the cap-and-trade regulation.

The proposed MRR amendments are also intended to align California's requirements with new federal requirements. On October 30, 2009, the United States Environmental Protection Agency (U.S. EPA) adopted its final Mandatory Reporting Rule[8] (the "EPA rule") for GHG emissions.

The revised MRR requirements, if adopted by the Board, would first apply to reporting in 2012 for 2011 emissions. Until the new requirements take effect, those entities now subject to MRR requirements will continue to report under the

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[8] U.S. Environmental Protection Agency Final Rule on Mandatory Reporting of Greenhouse Gases. Promulgated by U.S. EPA on October 30, 2009 and July 12, 2010, http://www.epa.gov/climatechange/emissions/downloads09/GHG-MRR-Full%20Version.pdf

current regulation. The following sections briefly summarize the major changes being proposed to the MRR. See the Initial Statement of Reasons and proposed regulatory language for the MRR for more information.

1. Harmonization of MRR with U.S. EPA Requirements and Cap-and-Trade

Since the adoption of California's reporting requirements, the U.S. EPA has adopted federal GHG reporting requirements. ARB is working to harmonize California's reporting requirements with the U.S. EPA rule. Many facilities in California will be subject to both reporting programs. Staff is working toward a unified reporting system to satisfy both state and federal requirements while minimizing duplicative or conflicting reporting obligations for facilities subject to both rules.

In developing harmonized reporting requirements for use in California, staff adhered to the following principles:

1. A California facility should be able to comply with both the MRR and the U.S. EPA rule by following a single set of monitoring, recordkeeping, and reporting requirements.

2. The quantification methodologies must be sufficiently reliable and accurate to be used to support a cap-and-trade program.

The most straightforward way to follow the first principle would be to adopt the U.S. EPA rule without change, but this approach would not adhere to the second principle. As U.S. EPA has acknowledged, the U.S. EPA rule has not been specifically designed to meet the needs of a cap-and-trade program.

In nearly all cases where modification to the U.S. EPA rule was necessary to support the cap-and-trade program, staff included additional requirements in the MRR, without any alterations to the U.S. EPA program. This will allow a facility to still submit a report to California while complying with the U.S. EPA rule. The U.S. EPA rule generally allows a facility to use different tier quantification methodologies. For covered sources in cap-and-trade, the MRR is generally more prescriptive than the U.S. EPA rule by requiring the use of higher tier methods and MRR-specific procedures for missing data replacement. Facilities subject to cap-and-trade requirements will report at the unit level using methods usually consistent with higher-tier options in the U.S. EPA rule, while other facilities may use any method from the U.S. EPA rule.

2. Threshold for Reporting

Entities subject to reporting under the MRR amendments are those with annual emissions equal to or greater than 10,000 $MTCO_2e$. The threshold for entities to be directly included in the cap-and-trade program is annual emissions equal to or greater than 25,000 $MTCO_2e$. Emissions from combustion of eligible biomass-derived fuels must be reported, but do not have a compliance obligation

associated with them in the cap-and-trade program. Staff proposes a lower reporting threshold for several reasons. Reporting down to a threshold of 10,000 $MTCO_2e$ is needed to determine whether the threshold for inclusion in the cap-and-trade program is set at the appropriate level to capture the largest emissions sources. The lower reporting threshold is also required to monitor potential leakage to facilities or entities below the threshold of the cap-and-trade program.

3. Verification

The cap-and-trade program demands rigorous GHG accounting, reporting, and verification of emissions data. The MRR will continue to require independent third-party verification of emission reports by entities and facilities included in the cap. Verification is not required for reporters under the 25,000 metric ton CO_2e threshold; however, they are still subject to ARB audits. ARB will continue to accredit third-party verification bodies and verifiers for emissions reporting. In the amended MRR, the verifier accreditation program will be expanded to also accredit third-party offset verifiers.

C. Applicability

The proposed cap-and-trade regulation establishes a program that covers GHG emissions from multiple sectors. In the initial compliance period, beginning in 2012, the program will cover emissions from electricity, including imported electricity; industrial fuel combustion at large sources; and industrial process emissions, excluding fugitive emissions. In the second compliance period, beginning in 2015, the program will expand to include fuel distributors, to cover emissions associated with transportation fuels and fuels combusted at industrial, residential, and commercial buildings that are not otherwise covered directly as large emissions sources. The first compliance period of the program will include about 37 percent of the economy-wide emissions in California. Starting with the second compliance period, the program will include approximately 85 percent of emissions. The program could be expanded in the future based on new information.

The proposed regulation defines and includes requirements for covered entities, opt-in covered entities, and voluntarily associated entities. Under this regulation, covered entities and opt-in covered entities will be required to register with ARB, report their emissions annually, acquire compliance instruments, and surrender compliance instruments to match their emissions for the compliance period. Voluntarily associated entities must also register with ARB. These requirements are discussed in the following sections.

1. Covered Gases

Under the proposed cap-and-trade regulation the following gases are covered: carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), hydrofluorocarbons

(HFCs), perfluorocarbons (PFCs), sulfur hexafluoride (SF_6), and nitrogen trifluoride (NF_3).[9] Staff proposes to include all GHGs listed in AB 32 in the proposed regulation, even though some may not generate a compliance obligation in the program at this time. This will allow staff to include emissions associated with these gases in the future.

2. Covered Entities

Covered entities are those that exceed the annual cap-and-trade emissions threshold and, therefore, have a compliance obligation in the program. Covered entities include: operators of large industrial sources of GHG emissions, first deliverers of electricity (the first entity that delivers electricity to the California grid), and fuel suppliers. Covered entities must submit compliance instruments to match the amount of verified emissions they report.

Staff proposes broad coverage of sources and emissions under the cap-and-trade program to provide greater certainty that economy-wide emissions reductions will be achieved and provide more opportunities for reductions and trading. Operators of large point sources and first deliverers of electricity will be included under the cap in 2012. Electricity and large industrial sources are included at the outset of the program because they represent a significant amount of emissions from relatively few sources. Accurate emissions reporting and monitoring methods and requirements already exist for these sources. AB 32 also requires ARB to account for emissions of imported electricity (HSC §38530(b)(2)). Therefore, staff proposes to include in the program emissions that result from electricity generated out of state and consumed in California.

Staff proposes to include residential and commercial fuels, as well as transportation fuels, in the program starting in 2015 because together they are the largest source of GHG emissions in California. Including transportation fuels and fuel suppliers will help achieve the objective of reducing emissions not only by 2020, but also help to drive the long-term transition to cleaner fuels well into the future. Additionally, including these fuels in the program provides a consistent price on GHG pollution throughout the economy and ensures a level playing field across all fuels and consumers. Consequently, staff concluded that there are important benefits from including transportation fuels and fuels for residential, commercial, and small industrial users. While there would be benefits to including these fuels in the first compliance period, staff believes that it is appropriate to initially bring these fuels into the program on a reporting-only basis for the first compliance period. This will provide time for both ARB and the fuel deliverers to work through any issues in the reporting system before they have a compliance obligation.

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[9] HSC § 38505, as amended by Senate Bill 104, Oropeza, 2009.

3. Point of Regulation by Emissions Source

Point of regulation refers to the entities that must demonstrate compliance by submitting compliance instruments. As shown in Table II-1, staff proposes different points of regulation strategies, depending on the sector.

Table II-1: Timing and Point of Regulation by Emissions Source

Sources of Emissions	Point of Regulation	Year Entering the Program
In-State Electricity Generation	Those who generate electricity in-state and deliver it to the California electricity grid	2012
Imported Electricity	First deliverers of electricity to the California electricity grid	2012
Industrial – Combustion and Process Emissions	The source for large stationary combustion and process emission sources	2012
Carbon Dioxide Suppliers	Those who supply carbon dioxide	2012
Commercial/ Residential/Small Industrial Combustion	Where fuel is distributed, including natural gas local distribution companies (LDCs) and natural gas transmission pipelines	2015
Liquefied Petroleum Gas Combustion	Those who import or produce liquefied petroleum gas, including fractioners or refiners	2015
Transportation Fuel Combustion	Enterers and position holders of transportation fuels, and producers of biomass-derived fuels	2015

a. Electricity Deliverers

As required by AB 32 (HSC 38530(b)(2), ARB will account for emissions associated with both imported power and power generated in California. Staff proposes a first deliverer approach that regulates the first responsible party for placing power onto the California grid, because it treats all importers and in-state generators the same. The covered entity for in-state electricity generation is the source of generation. For emissions associated with imported electricity, the covered entity will be the first entity to place power onto the California grid. Electricity deliverers are responsible for deliveries of both specified and unspecified electricity delivered to the California grid. These entities include electrical distribution utilities (those that sell electricity to retail customers) and marketers (those that buy and sell in the wholesale electricity market). Typically these entities can be identified as purchasing-selling entities by the North American Electric Reliability Council (NERC) e-Tag.[10]

b. Industrial Process Emissions

For large stationary sources with industrial process emissions, the covered entity will be the facility operator. Staff believes facility operators are most likely to have the authority to plan and implement GHG reduction projects at these large stationary sources. This point-of-regulation approach is identical to that taken in the MRR.

c. CO_2 Suppliers

For use of CO_2 as an industrial gas, the covered entity would be the supplier of CO_2 because they are involved in the sale and delivery of the gas for commercial uses.

d. Fuels

To cover the emissions from transportation fuel combustion and that of other fuels by residential, commercial, and small industrial sources, staff proposes to regulate fuel suppliers based on the quantities of fuel consumed by their customers. Fuel suppliers will be required to report emissions as specified in the MRR. While many of these suppliers will have a cap-and-trade compliance obligation, some who utilize eligible biomass-derived fuel sources may be reporting for informational purposes only. In no case would an entity have a cap-and-trade obligation without having a reporting obligation.

i. Natural Gas Suppliers

For natural gas combustion emissions, the covered entity is the supplier, meaning the owner when the fuel is distributed. *Natural gas suppliers* are

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[10] North American Electric Reliability Corporation (NERC) electronic tag representing transactions on the North American bulk electricity market scheduled to flow between or across control areas.

defined as public utility gas corporations, publicly owned natural gas utilities operating in California, and owners and operators of intrastate pipelines that distribute natural gas directly to end users and are not part of utility pipeline systems.

ii. Suppliers of Transportation Fuels

For transportation fuel combustion emissions, the covered entity is the supplier of the fuel. Transportation fuel suppliers are limited to position holders (those who own fuel) at terminal racks that dispense Reformulated Gasoline Blendstock for Oxygenate Blending (RBOB) and/or diesel fuel, and enterers (those who bring in fuel from outside the State) that deliver fuel outside of the terminal system. This point of regulation is similar to the method used for imported electricity where the owner at the first point of receipt has a compliance obligation. ARB staff will continue to evaluate the concept of position holders relative to railroads and other specific types of fueling operations and may propose modifications to the regulations as appropriate.

iii. Suppliers of Liquefied Petroleum Gas

For liquefied petroleum gas (LPG) the covered entity is the LPG supplier. *Suppliers of LPG* are defined as producers, including fractioners and refiners, and importers of LPG. Staff proposes to include LPG because of its substantial contribution to the statewide GHG inventory.

4. Opt-In Covered Entities

The proposed regulation includes provisions for entities that do not meet the cap-and-trade threshold requirements but choose to voluntarily participate in the cap-and-trade program. These entities are referred to as "opt-in covered entities." Staff included provisions for these entities to be eligible to receive free allowances for implementing more efficient processes and technologies to reduce their associated emissions. If an entity opts into the program, it is subject to all reporting, verification, and compliance obligations of covered entities from the date of opt-in through the end of the current compliance period.

5. Voluntarily Associated Entities

The proposed regulation describes requirements for entities who do not have a compliance obligation but who may participate in the auctions, secondary market, [11] and tracking system. Voluntarily associated entities may include non-governmental organizations or private individuals wishing to purchase allowances for the sole purpose of retiring them. Voluntarily associated entities may also include participants such as traders, brokers, offset providers, or

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[11] The secondary market refers to a market that is established by trading compliance instruments after initial distribution of allowances through ARB auctions or allocations.

financial institutions. Staff chose to allow these other market participants to increase liquidity in the market and to facilitate the buying and selling of allowances between emitters and counterparties. In addition, more market participants make it less likely for a particular market player to affect the price of allowances by acquiring too many.

Although voluntarily associated entities may participate in the secondary market, purchase allowances at ARB auctions, and participate in the tracking system, only covered entities and opt-in covered entities are eligible to receive allowances through direct allocation or buy them from the Reserve.

D. Compliance Instruments

The proposed regulation includes two kinds of compliance instruments—allowances and offsets—to allow covered entities to meet their compliance obligations. Approved compliance instruments can be issued by ARB or other programs that are approved by the Board for linkage. Each allowance or offset equals one metric ton of CO_2e. California-issued allowances and offsets, and approved compliance instruments from other programs, constitute the total number of compliance instruments available to covered entities to comply with the cap-and-trade program.

1. California Greenhouse Gas Allowances

ARB will issue allowances equal to allowable GHG emissions under the cap. Each allowance authorizes its owner to emit one metric ton of CO_2e and has an economic value which depends on the supply of allowances (and offsets) and the demand to emit GHGs. To achieve GHG emissions reductions, the number of allowances issued is reduced over time. These allowances can be distributed by various methods, including: auctioning, benchmarking, and grandfathering.

2. Offsets

An offset credit represents a reduction or removal of GHG emissions. These GHG emissions reductions or removals result from activities not covered by the cap-and-trade program, but must be monitored, quantified, and verified on an individual project basis. This credit can then be sold and used by a covered entity to meet a portion of its compliance obligation under the cap-and-trade program. Like an allowance, each offset credit authorizes its owner to emit one metric ton of CO_2e.

The number of offset credits that a covered entity may use to meet its compliance obligation will be limited. Offset credits must be real, additional, permanent, verifiable, enforceable, and quantifiable. Specific considerations and design elements of the offset program can be found in Chapter III—Overview of the Compliance Offsets Program.

3. Allowances and Offsets from Other Programs

The proposed regulation provides a framework for allowances and offsets from other approved programs (such as another cap-and-trade program, an offset registry, or a sector-based crediting program) to be used to meet compliance obligations. The use of such instruments can help reduce compliance costs for emitters by expanding the available opportunities for low-cost emissions reductions and the market for new technologies.

The proposed regulation establishes a process by which each program would be evaluated on a case-by-case basis before being considered by the Board. In approving an external program, the Board would also specify what compliance instruments from that program would be accepted for compliance use in California's program. Recognition of another program's compliance instruments or linkage would be implemented by program-specific contracts or memoranda of understandings, as applicable. This Chapter's Section L: Linkage and Section N: Recognition of Compliance Instruments from Other Programs discuss the process for approving other programs.

E. Registration and Accounts

1. Development and Implementation of a Market Tracking System

The proposed program will require a market tracking system (MTS) to record information about the holders of compliance instruments and trades of compliance instruments among market participants. ARB is working closely with our WCI partners on two possible approaches, (1) developing a single MTS that will serve all WCI partner programs, or (2) ensuring that the different tracking systems that are developed can communicate in a manner to allow linkage of the market programs.

The primary goal of the MTS will be to support the effective implementation of the cap-and-trade regulation and to reduce the costs and administrative burden associated with long-term cap-and-trade responsibilities. Additionally, the MTS will collect the information necessary for a secure, liquid, and transparent allowance market.

The MTS as a whole is scheduled to be operational in 2012. ARB is working to make the auction, market registry, trade data repository, and compliance sub-systems of the MTS operational by the end of the third quarter of 2011 to enable the cap-and-trade program to begin operation on January 1, 2012.

2. Registration

The proposed regulation includes requirements for any entity that wishes to hold compliance instruments, including registration with ARB. When an entity registers with ARB, it must disclose all affiliated entities, provide information to allow ARB to oversee the market, and agree to be subject to ARB's regulatory requirements. Once registered with ARB, an entity can possess an ARB account for holding, transferring, and surrendering compliance instruments. Each entity will specify who has the authority to access its accounts when it registers.

3. Accounts

ARB will establish three types of accounts in the MTS to track ownership and trades of compliance instruments: Holding Accounts, Compliance Accounts, and Limited Use Holding Accounts. All entities holding compliance instruments must have a Holding Account. Covered and opt-in entities will meet their compliance obligations by transferring allowances and offsets from their Holding Accounts to their Compliance Accounts. Because they have no compliance obligation, voluntarily associated entities will only be approved for Holding Accounts to buy, sell, and voluntarily retire compliance instruments.

Limited Use Holding Accounts will be created for electricity utilities that will receive free allowances. Holders of these accounts may only sell their directly allocated allowances on a consignment basis through the general quarterly auction held by ARB or, for publicly owned utilities, transfer them to their Compliance Account. For more information on Limited Use Holding Accounts, please refer to Section I of this Chapter—Direct Allocations of California Greenhouse Gas Allowances.

4. Designation of an Authorized Account Representative

Staff proposes that transfers of compliance instruments only would be recorded by the accounts administrator (the ARB Executive Officer or designee) if the transaction is authorized by the account representative. An authorized account representative must be designated by the account holder to conduct transactions. Staff is proposing procedures for authorized account representatives to ensure integrity of transfers between accounts by preventing controversy over who has authority to conduct a transaction.

F. California Greenhouse Gas Allowance Budgets

The initial 2012 allowance budget was set based on the best estimate of actual emissions in 2012 for those sources that will be covered at the outset of the program. In 2015, the program will expand to cover fuel suppliers. The allowance budget in 2015 expands to reflect this increased coverage.

The 2020 target for the cap-and-trade program was initially set through the Scoping Plan process as the emission level needed from capped sources to reach the overall AB 32 economy-wide target. The estimated 2020 cap from the Scoping Plan (365 $MMTCO_2e$) was based on ARB's top-down inventory of greenhouse gas emissions. Since the adoption of the Scoping Plan, the MRR has resulted in facility level data, which has allowed staff to develop a better estimate of the emissions from sources in the program. As a result, staff adjusted the Scoping Plan estimate of the 2020 cap to account for the revised estimate of emissions covered by the cap-and-trade program. Subsequently, the cap for 2020 has been set at 334.2 $MMTCO_2e$. Since the Scoping Plan, staff have refined the coverage of the cap-and-trade program and improved emissions estimates for the covered entities using facility-level data gathered through the MRR program.

After staff set the initial allowance budgets for 2012, 2015, and 2020, it defined annual budgets for the intervening years. Staff established a linear decline from 2012 to 2015 and then from 2015 to 2020. Staff believes that a linear trajectory is the most straightforward method for reducing the cap. The specific methodology and data used for setting the annual allowance budgets can be found in Appendix E: Setting the Program Emissions Cap.

Annual allowance budgets for calendar years 2012–2020 are established in the proposed regulation, so that the total number of allowances issued in each year through 2020 are known. Table II-2 shows the number of allowances created for each year from 2012 through 2020.

These annual budgets were set to include all GHG emissions associated with imported electricity. Each time California links to a WCI partner jurisdiction from which California imports electricity, staff will need to reevaluate these annual budgets to prevent double-counting of these emissions.

The proposed regulation includes three-year compliance periods, with the first commencing on January 1, 2012. At the end of each three-year period, covered entities are required to surrender enough compliance instruments to match their verified emissions from that period. A three-year compliance period provides some temporal flexibility by allowing covered entities to manage planned or emergency changes in operations over the short term, as well as to deal with low water years that might affect the generation of hydroelectric power.

Table II-2: Annual Allowance Budgets from 2012–2020

	Allowance Budget Year	Annual Allowance Budget (Millions of CA GHG Allowances)
1st Compliance Period	2012	165.8
	2013	162.8
	2014	159.7
2nd Compliance Period	2015[12]	394.5
	2016	382.4
	2017	370.4
3rd Compliance Period	2018	358.3
	2019	346.3
	2020	334.2

G. Compliance Requirements for Covered Entities

The program will apply an emissions threshold of 25,000 $MTCO_2e$ annually to determine which entities will have a compliance obligation.[13] Covered entities must comply with program requirements if they emit this threshold or greater. Any entity whose emissions exceed the threshold in any year of a compliance period has a compliance obligation for that compliance period and the next compliance period, unless it has shut down all processes. To comply with the regulation, covered entities must report their emissions annually according to the requirements of the MRR and submit sufficient compliance instruments to cover their verified emissions at the end of each three-year compliance period. Covered entities must also surrender compliance instruments to match a portion of their reported emissions each year.

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[12] In 2015, annual allowance budgets are adjusted to reflect emissions from fuel suppliers.
[13] Emissions from combustion of eligible biomass-derived fuels must also be reported, but do not have a compliance obligation associated with them. Anything that is not verified as an eligible biomass-based fuel would be counted when calculating applicability and compliance obligation.

5. Calculating Compliance Requirements

a. Operators of Facilities

An operator of a facility has a compliance obligation if its emissions exceed the 25,000 $MTCO_2e$ inclusion threshold, including process, industrial gas, or stationary combustion emissions. In the case that the operator receives an adverse verification statement[14] or does not report its GHG emissions by the deadline in the MRR, the compliance obligation will be assigned by ARB. This assigned emissions level will be based on staff's evaluation of the following: normal days and hours of operation, previous emissions data reports, potential maximum fuel and process material input and output capacities, wholesale and retail transactions (for electric power entities), and information reported to ARB or other agencies related to the reporting entity's facility.

b. First Deliverers of Electricity

The electricity sector includes both in-state generation and electricity imported into the State. Sources of California's electricity include natural gas, large hydropower, coal, nuclear, cogeneration, and renewable energy facilities. In-state electricity sources supplied approximately 68 percent of California's electricity in 2008.[15] In-state generation was responsible for 44 percent of electricity emissions. Imported electricity accounted for 31 percent of California's electricity supply, and 56 percent of California electricity sector emissions.

Compliance obligations for emissions from the electricity sector are based on the emissions from plants that generated the electricity, if the source of the electricity generation is known. If the source is unknown, the compliance obligation is based on megawatt-hours (MWh) and a default emission factor, which is discussed below.

Compliance obligations for electricity are calculated based on the emissions from the generating facility, if the facility is known. This is referred to as *specified power.* In this case, ARB knows what fuel was used to generate the electricity. For specified power, staff developed reporting factors that determine how many GHG emissions to assign to the specified power based on the fuel source used to generate the electricity. The threshold for determining compliance obligations for specified power is 25,000 $MTCO_2e$ through 2014. In the first compliance period, in-state power plants below the 25,000 $MTCO_2e$ threshold are not covered, even if it is specified as in-state power generation.

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[14] A verification statement rendered by a verification body attesting that the verification body cannot say with reasonable assurance that the submitted emissions data report is free of material misstatement.

[15] California Energy Commission. 2008. Net System Power Report. Additionally, Total System Power for 2008. Found at: http://energyalmanac.ca.gov/electricity/system_power/2008_total_system_power.html.

Electricity generated outside of California and imported into the State from an unknown source is referred to as *unspecified power.* This type of electricity is purchased on the electricity market, which experiences a large number of transactions each hour. The electricity is bought and sold many times before it is delivered to the California electricity grid. For this type of electricity, there is no threshold for the compliance obligation, because it is not possible to trace it back to the generator. Since ARB does not know the source of electricity, staff does not know the amount of GHG emissions to assign to it. Therefore, staff proposes to use a default emissions factor for unspecified power. Staff recommends the emissions factor be based on average emissions associated with the available electricity generation that could be sold on the spot market and brought into California. The GHG emissions will be calculated by multiplying this emission factor by the MWh delivered.

Changes in the reported mix of imported electricity that shift emissions within the Western Electricity Coordinating Council (WECC) region but do not reduce emissions overall should not result in a reduced compliance obligation. Staff is developing requirements to ensure reductions are real and not the result of incomplete accounting. In this way, the California cap-and-trade program will encourage low-emitting electricity generation for both in-state production and imported power.

In 2015, when natural gas is covered by the regulation, emissions from all electricity generated in-state will be indirectly covered for any specified power plants. Beginning in 2015, the compliance threshold for facilities supplying specified imported electricity will be zero, to account for the addition of natural gas fuel coverage and to be consistent with the approach for covering all electricity deliveries in the program beginning in that year.

Electricity generating facilities that are solely powered by nuclear, hydroelectric, wind, or solar energy do not have a compliance obligation because these fuel sources do not directly emit GHGs.

c. Fuel Suppliers

Fuel suppliers are responsible for the emissions resulting from the combustion of the fuel they supply. In this way, a fuel supplier is acting on behalf of its customers who are emitting the GHGs. Facilities and fuel suppliers are distinct in that facilities are treated as physical locations and, therefore, they are covered entities based on operational control. Fuel suppliers are treated as corporate entities that are responsible for compliance.

i. Suppliers of Natural Gas

Because large industrial facilities and electricity deliverers will be responsible for emissions stemming from natural gas combustion, suppliers of natural gas will have a compliance obligation for the combustion emissions of all gas delivered, less the emissions from gas that is delivered to covered entities. This approach will ensure that these emissions are not double-counted.

ii. Suppliers of Transportation Fuels

Suppliers of transportation fuels will have a compliance obligation for the combustion emissions from fuel that they sell, distribute, or otherwise transfer for consumption in California, including RBOB, and Distillate Fuel Oils No.1 and 2.

iii. Suppliers of Liquefied Petroleum Gas

Suppliers, including producers and importers, of liquefied petroleum gas (LPG) will have a compliance obligation for the combustion emissions from fuel sold in California. LPG producers, including fractioners and refiners, of liquefied petroleum gas have a compliance obligation for emissions that results from the full combustion or oxidation of all fuel sold, distributed, or otherwise transferred in California. LPG importers have a compliance obligation for emissions that result from full combustion or oxidation of all fuel imported into California.

d. Other Sectors and Categories of Emissions

i. Combined Heat and Power

Staff proposes that emissions associated with electricity generated from combined heat and power (CHP) operations have a compliance obligation if the industrial facility's total emissions exceed 25,000 $MTCO_2e$.

ii. Biomass-Derived Fuels

Staff proposes to treat direct and indirect emissions from combustion of biomass-derived fuels equally under the proposed regulation. Combustion emissions from specified biomass-derived fuels are excluded from compliance obligations if the biomass-derived fuel is reported and verified pursuant to the MRR. If the start-up fossil fuels that supplement biomass-derived fuel combustion at facilities and unverified biomass-derived fuels exceed the cap-and-trade threshold, the facility would be subject to cap-and-trade requirements based on emissions from these sources.

The MRR requires rigorous verification to validate any emissions reported as biomass-derived fuel emissions that would not generate a compliance obligation. In the absence of certification of the fuel by an accredited certifier of renewable biomass-derived fuels, a verification body must verify a biomass-derived fuel that will not be subject to a compliance obligation pursuant to provisions in MRR. If the verification body is unable to verify the biomass-derived fuel, it will be subject to a compliance obligation for emissions associated with its combustion.

To avoid potential double-counting of emissions reductions from biomass-derived fuels, any source of biomass-derived fuels that applies for offset credits under any ARB-approved offset protocols will be ineligible to be exempt from generating a compliance obligation. This includes but is not limited to the California offset program or any other mandatory or voluntary offset program.

iii. Landfills and Wastewater Treatment Facilities

The proposed regulation excludes emissions from the combustion of biomass produced in solid waste management and wastewater treatment facilities from compliance obligations, if they can verify or certify their biomass through the MRR verification process. Facilities whose emissions from the combustion of fossil fuels and unverified or uncertified biomass-derived fuels exceed 25,000 $MTCO_2e$ will have a compliance obligation. A few large wastewater treatment facilities or landfills may fall into this latter category.

iv. Waste-to-Energy Electricity Generation

Electricity deliverers that use biomass-derived fuels (e.g., waste-to-energy facilities) would have a compliance obligation for any biomass-derived fuel that is not verified through the MRR process. Emissions from deliveries associated with the combustion of fossil fuels and unverified or uncertified biomass-derived fuels that exceed 25,000 $MTCO_2e$ will have a compliance obligation.

6. Timing of Compliance Obligations

Staff proposes to require three-year compliance periods to provide increased compliance flexibility and address price volatility that may be caused by annual variations in electricity sector emissions. Staff also recognizes that there is a need to require covered entities to submit a portion of its compliance obligation more frequently to ensure they are making progress toward their obligations. Covered entities could emit GHGs and then declare bankruptcy or otherwise cease operation before fulfilling their compliance obligations at the end of the three-year compliance period. Any compliance instrument that an entity owns at the time of bankruptcy could be included in its collection of assets for bankruptcy proceedings, thereby prohibiting claims to it by ARB. This form of default would hinder California's ability to meet the cap and the requirements of AB 32.

To reduce the impact of such a scenario, the proposed regulation requires covered entities to turn in a percentage of its verified emissions at intervals during the compliance period. ARB is proposing an "annual compliance obligation" to reduce the potential for a covered entity to default on a three-year compliance obligation.

In addition to the annual compliance obligation, the total obligation for a compliance period is resolved after positive or qualified positive verification statements for the third year are received and reconciled.

A covered entity will surrender compliance instruments to meet its compliance obligation by transferring the serial numbers from its Holding Account to its Compliance Account. Once transferred, compliance instruments may not be transferred back to a Holding Account. Entities can surrender allowances from the allowance budget years within the three-year compliance period, or from an earlier compliance period, to satisfy their compliance obligation. Allowances issued by ARB for an allowance budget year later than the compliance period

cannot be used for compliance in the current period, except for allowances purchased from the Reserve.

a. Annual Compliance Obligation

A covered entity will be required to surrender compliance instruments in each of the first two years of a compliance period equal to 30 percent of its verified emissions for that year. For a covered entity that reports emissions in April under the MRR, the proposed surrender will be due by May 15 of the same year. For a covered entity that reports in June under the MRR, the surrender will be due by July 15 of the same year.

b. Triennial Compliance Obligation

The triennial surrender obligation is the covered entity's total verified emissions over the three-year compliance period, less the two annual surrender payments. ARB will work with covered entities to resolve any data issues related to verification. After ARB makes a final determination of the amount of an entity's compliance obligation based on its verified emissions and the validity of its surrendered compliance instruments, it will determine whether the covered entity has submitted a sufficient number of compliance instruments. The surrender deadline will be November 1 of the calendar year following the third year of the compliance period.

c. Untimely Surrender of Compliance Instruments

In the proposed regulation, covered entities must submit one allowance or offset credit by the compliance deadline for each metric ton of CO_2e emitted. Any emissions that exceed the number of valid compliance instruments surrendered by the deadline will be considered *excess emissions,* and the entity will be subject to excess emissions provisions. The excess emissions provision is intended to discourage untimely compliance. Four allowances issued by California or a linked program must be turned in for each metric ton of excess emissions. To avoid constricting the total supply of allowances, three of the surrendered allowances will be placed into the Reserve and offered for purchase. One of the allowances will be retired to fulfill the entity's original compliance obligation.

7. Offset Quantitative Limit

To drive emissions reductions and incentivize innovation from sources within capped sectors, staff proposes to limit the number of offsets that may be used to meet a compliance obligation. The limit is expressed as a portion of the covered entity's emissions. Using the sum of the annual allowance budgets, staff calculated the total limit on the use of offsets and applied the limit to all covered entities in the program in all of the compliance periods.

The Preliminary Draft Regulation (PDR) described a four percent limit on the use of offsets for an individual entity's compliance obligation. This established a level of program stringency by allowing only 111 million offsets to be used over the life

of the program, in addition to the number of allowances issued by ARB. The proposed regulation would establish an Allowance Price Containment Reserve in which ARB will place a total of 121 million allowances at the beginning of the program. By removing these 121 million allowances from the program, the level of stringency is increased, which could result in higher allowance prices. To address this, staff proposes that additional offsets, equal to the amount of allowances that are placed into the Reserve, be allowed in the program. This means that a maximum of 232 million offset credits may be used over the life of the program. This results in an offset limit in which a maximum of 8 percent of an individual entity's compliance obligation can be met using offsets.

H. Allowance Allocation

Allocation refers to how ARB distributes the allowances it issues. Allowances can be sold, freely allocated based on specific criteria, or some combination of the two. Because allowances are tradable among those in the market, they have value whether they are auctioned or freely distributed. If ARB sells allowances, an auction is the fairest and most transparent way to distribute allowances. When allowances are auctioned, they are distributed to the winning bidders. The proceeds collected from the sale of the allowances sold at auction could be used for a variety of purposes, including public benefit.

Staff proposes an allocation approach designed to give businesses and industries in the State sufficient time to reduce their emissions in a cost-effective manner, without unnecessary short-term costs. Therefore, in the proposed regulation, staff proposes a phased approach to the development of an auction system, beginning with a high percentage of free allocations to program participants. Staff also recognizes that the long-term success of the program will require significant investment in emissions reductions. However, under current economic conditions, an early emphasis on auction could hamper the ability of California sources to invest in low-carbon technologies. Further, as discussed below, freely allocating allowances in the early years of the program will help prevent leakage. Allocating the allowances for free using emissions efficiency benchmarks will reward companies that have already made investments in energy efficiency and carbon reductions, and will not penalize those that produce goods in California. The overall allocation approach includes: creation of an Allowance Price Containment Reserve for cost-containment purposes, free allocation to the industrial sector for transition assistance and leakage prevention, free allocation to electrical distribution utilities on behalf of ratepayers, and auction of the remaining allowances.

1. Establishment of an Allowance Price Containment Reserve

Key to the proposed cap-and-trade program is providing compliance flexibility while ensuring that emissions goals are achieved. To expand flexibility and reduce compliance costs, staff proposes to create an Allowance Price Containment Reserve. The ability of covered entities to purchase allowances from the Reserve will increase the supply of allowances in the market, thereby

moderating the price as long as allowances remain in the Reserve. This reserve will hold allowances that will be made available for purchase by covered entities at fixed prices at direct quarterly reserve sales held three weeks after each general auction. Allowing covered entities to purchase allowances from the Reserve at fixed prices will limit increases in the market price as it approaches the established fixed reserve price. The Reserve will be filled: (1) at the beginning of the program with a portion of allowances from each budget year, (2) with ARB allowances that remain unsold at a direct auction, and (3) with allowances surrendered to comply with excess emissions provisions.

Staff proposes to redirect allowances at the beginning of the program and place them into the Reserve. Staff proposes that a greater percentage of allowances come from later years of the program to provide more flexibility in the early years of the program. The Reserve will be filled with 1 percent of allowances from each year from 2012 through 2014, 4 percent of allowances from each year from 2015 through 2017, and 7 percent of allowances from each year from 2018 through 2020. This is equal to approximately 5 percent of total allowances in the program from 2012 through 2020.

The Reserve will be organized into three equal tiers. Allowances in each tier will be available for purchase at fixed prices. Staff proposes to sell reserve allowances at prices of $40/metric ton for the first tier, $45/metric ton for the second tier, and $50/metric ton for the third tier in 2012. These prices will escalate by 5 percent plus the cost of inflation each year, such that the reserve prices are approximately $60/ metric ton, $67/ metric ton, and $75/ metric ton in 2020. Staff chose these prices to set them above the expected cost of abatement in the California program based on the economic analysis presented in Appendix N: Supporting Documentation for the Economic Analysis, the Updated Economic Analysis of California's Climate Change Scoping Plan,[16] the Updated Economic Analysis of the WCI Regional Program,[17] and trading prices in the European Union Emissions Trading Scheme (EU ETS). Staff also notes that British Columbia, one of our WCI partners, has a carbon tax that is scheduled to be $30/metric ton in 2012. Direct sales of reserve allowances will take place three weeks after each quarterly auction. Covered entities will place bids for the number of allowances they wish to buy from each tier at each price.

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[16] *Updated Economic Analysis of California's Climate Change Scoping Plan: Staff Report to the Air Resources Board.* March 24, 2010. http://www.arb.ca.gov/cc/scopingplan/economics-sp/updated-analysis/updated_sp_analysis.pdf (accessed September 23, 2010).

[17] Updated Economic Analysis of the WCI Regional Cap-and-Trade Program. July 2010. Found at: http://www.westernclimateinitiative.org/component/remository/Economic-Modeling-Team-Documents/.

Direct quarterly reserve sales are discussed in more detail in this Chapter's Section J: Auction and Sale of California Greenhouse Gas Allowances.

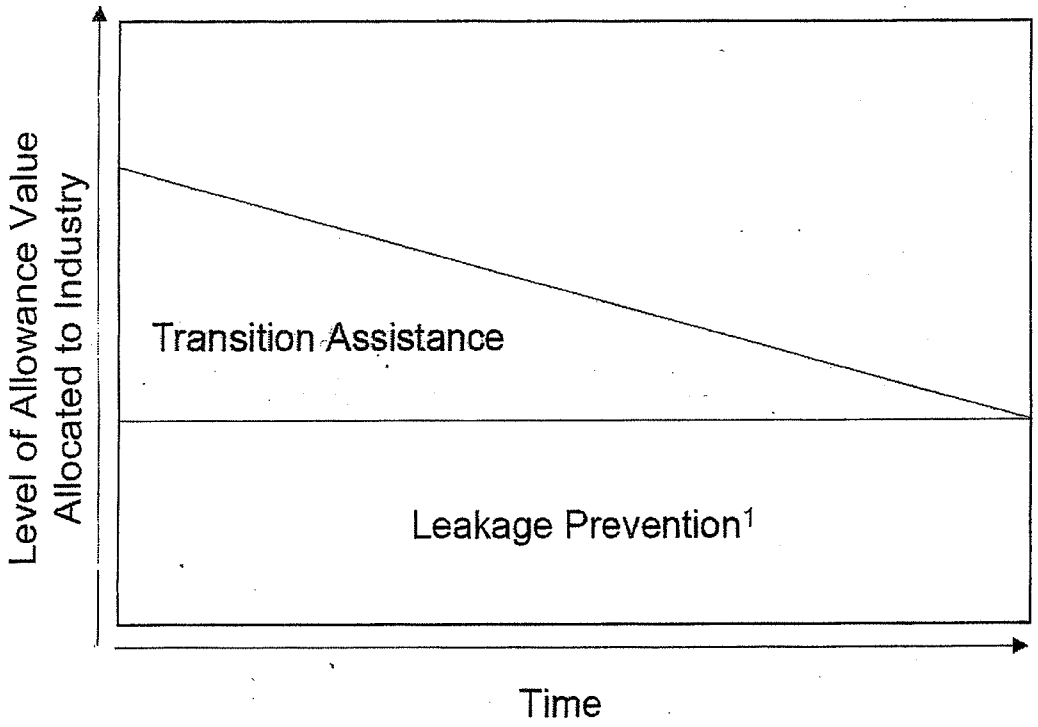
2. Allocation to the Industrial Sector for Transition Assistance and Leakage Prevention

Staff proposes to allocate allowances to the industrial sector for two purposes: (1) to provide transition assistance and (2) to prevent leakage. Transition assistance provides free allocation to the industrial sector at the outset of the program to avoid sudden or undue short-term economic impacts and promote a transition to a low-carbon economy. As depicted in Figure II-1, this transition assistance will decline as covered entities gradually adjust to the carbon price and adopt energy- and carbon-saving strategies. This level of free allocation will decline over time to settle at a level needed to prevent leakage.

If not appropriately compensated for in the design of the program, requirements for some energy-intensive trade-exposed (EITE) industries to reduce emissions in California, either through inclusion in a cap-and-trade program or through source-specific regulation, have the potential to create a disadvantage for California facilities relative to out-of-state competitors who do not face similar requirements. If production shifts outside of California to a region not subject to GHG emissions-reduction requirements, emissions could remain unchanged or even increase. This is referred to as emissions "leakage." AB 32 requires ARB to design measures to minimize leakage to the extent feasible. The cap-and-trade program is designed to minimize leakage in several ways, including accounting for both out-of-state and in-state electricity generation and linkage with partner jurisdictions in the WCI. Staff's allocation approach is also intended to minimize emissions leakage for those in the industrial sector.

Staff analyzed the potential for emissions leakage by looking at emissions intensity and trade exposure. *Emissions intensity* is a measure of the impact that carbon pricing will have relative to a sector's economic output. Those with higher emissions per unit of output are considered to be more emissions intensive. *Trade exposure* is a measure of a sector's ability to pass through a cost. Without assistance, the competitiveness of industries that are both highly emissions intensive and trade exposed has the potential to be negatively affected relative to competitors that do not face similar GHG emission reduction requirements. To minimize the potential for leakage, staff proposes to rely heavily on free allocation in the program's early years. See Appendix K: Leakage Analysis for a detailed analysis.

Figure II-1: Representation of Allowance Value Distribution for Transition Assistance and Leakage Prevention



[1] Mitigation of carbon costs that cannot be passed on due to leakage risk

Staff believes that free allocation to industrial entities at risk of emissions leakage will help maintain the competitiveness of California industries. For as long as ARB assesses that the risk of leakage persists, allowances will be allocated for free to those at risk.

To determine whether a sector is at risk of emissions leakage, staff developed a methodology to assess a sector's emissions intensity and trade exposure. Staff presents this in Appendix K: Leakage Analysis. The number of allowances that an individual facility will be allocated within a specific sector will be based on an emissions efficiency benchmarking approach. Under this approach, more efficient facilities will receive a greater amount of free allowances relative to their actual emissions. The amount of free allowances distributed under this approach will vary with economic conditions. This means that, in an economic downturn, there will likely be fewer allowances distributed for free due to a decrease in production or output. When economic activity is robust and output increases, a greater number of allowances will be freely allocated. The efficiency benchmarks for each sector are described in the regulation. As staff continues to work with stakeholders to finalize the regulation, there may be updates to these efficiency benchmarks. Any updates will be publicly noticed in accordance with the Administrative Procedures Act.

3. Allocation to Electrical Distribution Utilities

Electrical distribution utilities provide electricity to residential and small commercial customers. These entities include Investor Owner Utilities (IOUs) and Publicly Owned Utilities (POUs). Staff proposes to allocate allowances to electrical distribution utilities, as opposed to the generators, because electrical distribution utilities are best situated to utilize the value of allowances for ratepayer benefit.

To ensure that electricity ratepayers do not experience sudden increases in their electricity bills associated with the cap-and-trade regulation, staff proposes to allocate allowances for free to electrical distribution utilities on behalf of ratepayers. The proposed regulation stipulates that electrical distribution utilities must use the value associated with these allowances for the benefit of retail ratepayers of each electrical distribution utility, consistent with the goals of AB 32. They may not be used for the benefit of entities or persons other than their ratepayers. Allowance value could be used for rebates, customer bill relief, or to pay for GHG-reducing measures such as energy efficiency, renewable electricity generation, or other similar programs.

4. Voluntary Renewable Energy Allowance Set-Aside

The proposed regulation includes a placeholder for setting aside a small portion of the allowance pool to address the potential impacts of the cap-and-trade program on the voluntary renewable energy (VRE) market. At present individual decisions to purchase renewable energy in California can lead to reductions in greenhouse gas emissions. Implementation of the cap-and-trade program could change that dynamic because the amount of greenhouse gas emissions allowed will be pre-established by the cap level. As a result, decisions to purchase renewable energy free up emission allowances that would have been needed to generate electricity from fossil fuels, allowing other regulated entities to emit more than they could have otherwise. In essence, the voluntary purchase of renewable energy lessens the regulatory burden on greenhouse gas emitters.

Without an allowance set-aside for VRE purchase, once the cap-and-trade program is in place, the voluntary use of electricity generated from renewable resources and delivered to California would no longer contribute additional greenhouse gas emission reductions because the level of allowable emissions is determined by the cap. A VRE set-aside has been implemented in the cap-and-trade system in the US Northeast (the Regional Greenhouse Gas Initiative, or RGGI). In order to implement an effective VRE set-aside, ARB would need to establish clear accounting rules to determine the relationship of voluntary renewable energy generation and GHG emissions avoided. Additionally, a process for reviewing VRE purchase claims would be needed as part of the process of retiring allowances from the set aside. Because the accounting rules and process for retiring allowances from the set aside have not yet been developed and undergone review, the current regulation only includes a placeholder for future inclusion of this mechanism.

5. Auction of Allowances

Covered entities, opt-in covered entities, and voluntarily associated entities may all participate in the general quarterly auctions to buy allowances. When allowances are auctioned, the allowances are distributed to the winning bidders. The value of the allowances not freely distributed to the industrial sector and electrical distribution utilities that are auctioned is represented by the money paid to the State, which would then have the opportunity to use the revenue for public benefit.

According to the proposed regulation, after allowances have been placed into the Reserve and distributed to the industrial and electricity sectors, the remaining allowances issued for each year will be auctioned. The amount of allowances auctioned will increase over time as transition assistance is phased out and when distributed use of fuels is phased into the program in 2015. When ARB determines that the risk of emissions leakage abates for specific sectors, additional allowances may be auctioned. Auctioning can help establish price discovery; that is, provide a clear signal to market participants of the value of an allowance.

Some allowances will be auctioned directly by ARB; the proceeds will be placed into the Air Pollution Control Fund and made available for appropriation by the Governor and the Legislature for the purposes outlined in AB 32. How the Governor and Legislature apportion this portion of total allowance value will be important to the legacy of the cap-and-trade program. Staff recommends that these revenues be used primarily for the protection of California's consumers and to further the goals of AB 32. The following uses would achieve those ends:

- *Per Capita Consumer Rebate Program.* A significant amount of the allowances auctioned by the State in the second and third compliance period will likely be purchased by fuel suppliers to cover emissions associated with distributed fuel uses. Staff anticipates that these fuel providers will be able to fully pass the cost of acquiring these allowances to the consumers of these fuels. A per capita lump sum distribution of the proceeds raised at auction would help consumers avoid negative impacts of higher fuel expenditures while still providing the correct incentives to reduce fossil fuel use.[18]

- *Community Benefit Fund.* Staff recommends the creation of a Community Benefit Fund to recognize the community protection goals of AB 32.[19] ARB or another agency could administer a competitive grant program designed to promote projects that simultaneously reduce GHGs and co-

[18] See the recommendations of the Economic and Allocation Advisory Committee (Appendix L).
[19] Consistent with Health and Safety Code section 38565.

pollutants, finance adaptation/preparedness for climate change health impacts, create improvements to mass transit and land use planning, facilitate natural resource conservation, and support non-utility energy efficiency programs.

- *Low Carbon Investment Fund.* Staff received many suggestions that a portion of total allowance value be directed toward public investments in the energy innovation goals of AB 32. Various names have been proposed for this type of program including the "California Carbon Trust" and the "Investment Advisory Board."[20] Conceptually, this use of auction proceeds could be structured as a competitive grant program administered by ARB or another entity. Project types could include research, development and demonstration projects in zero- or low-GHG technologies, and/or support for a green technology workforce training program.

I. Direct Allocations of California GHG Allowances

The proposed regulation includes formulas which determine how many allowances each individual facility will be allocated for free. The number of allowances that an individual facility will receive is based on its output and the sector-specific emissions efficiency benchmark for those in the industrial sector, and a mix of historical emissions and sales for electrical distribution utilities. Staff is evaluating different approaches for allocation of allowances associated with the distributed use of natural gas. In the first compliance period, staff proposes to freely allocate the majority of allowances to the industrial and electricity sectors. Appendix J: Allowance Allocation, provides a more detailed discussion of the allocation approach being proposed, including discussion of how benchmarks will be applied in specific sectors.

1. Direct Allocation to Industrial Sectors

Staff proposes to use an updating output-based, free allocation methodology, combined with an emissions efficiency benchmark for allocating to industrial sources. This means that the amount of allowances given to each facility is based on its production activities in recent years compared with a sector-specific benchmark—the more a facility produces, the more free allowances it receives. The purpose of updating output-based benchmarking is to incentivize continued in-state production by tying the allowance value an entity receives to the amount

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[20] See the recommendations of the Economic and Allocation Advisory Committee (Appendix L) and the recommendations of the California Public Utilities Commission (CPUC) and the California Energy Commission (CEC) (Appendix M), as well as *Recommendations of the Economic and Technology Advancement Advisory Committee.* February 2008. http://www.arb.ca.gov/cc/etaac/ETAACFinalReport2-11-08.pdf (accessed 10/10/10).

of its in-state production. This method of allocation helps level the playing field with out-of-state manufacturers.

Staff also proposes to use emissions efficiency benchmarking to reward more efficient facilities on an emissions-per-unit-of-output basis. Benchmarking establishes an emissions performance standard for each sector. Depending on the processes of an industrial sector, it may use one of two types of benchmarks in the proposed cap-and-trade regulation: product-based and thermal energy-based.

A *product-based* benchmark sets an emissions performance standard per unit of output. For each unit of product that is manufactured, the benchmark will establish a standard level of emissions associated with its production. Ideally, staff would apply a product-based benchmark in every case. This type of benchmarking rewards efficiency throughout the production process all the way to the end product. However, applying a product-based benchmark is not feasible in the near-term for some sectors where the production processes are very similar, but they produce a wide array of products. For example, food processors produce hundreds of different products using a very similar production process (e.g., using heat or steam from an industrial boiler). In this case, staff would have to create benchmarks for many individual products, which is administratively burdensome and not feasible in the near-term. For these sources, staff proposes a fall-back approach using thermal energy-based benchmarks.

A *thermal energy-based* benchmark sets an emissions performance standard based on how efficiently a facility sources its energy. For such facilities, staff proposes to look at the types of fuels they use to determine the efficiency of their production processes. Since natural gas is the dominant fuel used in California manufacturing facilities, staff proposes to use the emissions factor associated with natural gas combustion as the benchmark for these sources. In this case, if a facility used a cleaner fuel source, like biomass, or combusts the fuel more efficiently, it would be rewarded with more allowances relative to its actual emissions. If a facility used a higher emitting fuel (like coal) or has an inefficient combustion process, it would not receive as many allowances relative to its actual emissions.

2. Direct Allocation to Electrical Distribution Utilities

Allowances will be freely allocated to the entities that provide retail electricity to California ratepayers, referred to as *electrical distribution utilities.* Requirements for how the freely allocated allowance value can be used differ for IOUs and POUs.

For IOUs, the allowances directly allocated to them must be auctioned at general quarterly auctions. The proceeds from these auctions must be used by the utility to mitigate the bill impacts of AB 32 programs on their distribution customers. Staff proposes that ARB place all allowances freely allocated to IOUs into their

Limited Use Holding Accounts. At each general auction, the utility must consign their allowances (put them up for sale at the auction). If the auction settlement price[21] exceeds the minimum set in the regulation, allowances are sold and the proceeds will go to utilities for the benefit of their ratepayers in the form of rebates, customer bill relief, or other AB 32 uses. If there are allowances that remain unsold at the general auction, they will be transferred back to the entity's Limited Use Holding Account for sale at the next auction.

In the current California electricity market, electricity is produced by both IOUs and independent generators. An IOU will have a compliance obligation for the emissions resulting from generation it operates. An independent electricity generator will have a compliance obligation for the emissions from the generation it operates. Both the IOU and the independent generator will purchase allowances at auction for their emissions. Because the price of electricity in the wholesale electricity market will reflect the cost of those purchased allowances, staff expects that independent generators will incorporate their cap-and-trade compliance costs into their bids in the wholesale power markets.[22] These costs will be paid by the IOUs when the power is purchased.

By requiring IOUs to put their allowances up for auction, the regulation maintains the current competitiveness of the deregulated California electricity market. In this way, utility-owned generation and independent generation have equal access to allowances.

Most POUs own and operate their own generation and do not compete with independent generators in the way IOUs do. Because of this, allowances directly allocated to POUs may either be consigned for sale at the general quarterly auctions or used directly to meet their compliance obligations. If a POU decides to auction some of its allowances at the general auction, the same auction rules apply to the POUs as those described above for the IOUs.

Each year, IOUs and POUs must report to ARB on the monetary value of auction proceeds and how the use of this value of the freely allocated allowances complies with the cap-and-trade regulation.

Staff is continuing to evaluate possible methods for allocating allowances among the electrical distribution utilities. The allocation must further the cap-and-trade emissions-reduction objectives, including providing incentives to cost-effectively

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[21] The *auction settlement price* is the price that all successful bidders will pay for their allowances and the price to be paid to those entities which consigned allowances to the auction.

[22] Some generators have reported that some existing contracts do not include provisions that would allow full pass-through of cap-and-trade costs. These contracts pre-date the mid-2000s and many may be addressed through the recently announced combined heat and power settlement at the California Public Utilities Commission. Staff is evaluating this issue to determine whether some specific contracts may require special treatment on a case-by-case basis.

reduce emissions. Additionally, the allocation must enable all the utilities to serve their customers reliably and affordably.

Staff recognizes that substantial effort is being asked of the electricity sector to realize environmental and energy security goals for California, which include addressing the following policy objectives:[23]

- Energy efficiency and demand response are the top priority for meeting future energy needs.
- Renewable energy is the preferred electricity supply resource, reflected in recently adopted renewable energy procurement requirements under the Renewable Electricity Standard (RES).[24]
- Combined heat and power and distributed generation are priorities, including the California Solar Initiative and the New Solar Homes Partnership.
- Continued reductions in the impacts of power plants on air quality and coastal and estuarine environments will be achieved with power plant efficiency and control improvements.
- Electrification of transportation is expected to contribute to energy security as well as environmental goals.

Utilities are committing significant resources to achieve these policy objectives, most of which help reduce GHG emissions.

Staff must also consider that, although all the utilities are moving toward these common policy goals, they currently have very different GHG emissions profiles and emissions-reduction opportunities. Some utilities, particularly in Southern California, have relied more on coal-fired electricity generation and have long-term commitments that were developed prior to concerns about GHG emissions and AB 32. Although Senate Bill 1368 (SB 1368, Perata, Chapter 598, Statutes of 2006) and its implementing regulations will result in substantial displacement of coal-based electricity imports from long-term commitments, existing contracts and ownership agreements have substantial remaining time periods; for instance, some stakeholders have stated that their existing agreements run through 2027 and would be costly to terminate. In Northern California, hydroelectric resources are more abundant, and those, combined with natural gas, result in a lower-

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[23] A summary is presented in *California's Clean Energy Future. An Overview on Meeting California's Energy and Environmental Goals in the Electric Power Sector in 2020 and Beyond*, California Energy Commission Report CEC-100-2010-002, September 2010, at: http://www.climatechange.ca.gov/energy/index.html (accessed 10/14/2010).

[24] *Renewable Electricity Standard*. California Air Resources Board. Found at: http://www.arb.ca.gov/energy/res/res.htm (accessed 10/10/10).

emitting generation portfolio. Additionally, the absence of long-term contracts tied to high-emitting resources provides more flexibility to reduce emissions prior to 2020.

This diversity of resources and emissions-reduction opportunities across utilities creates challenges for defining an allowance allocation method that provides proper incentives, is affordable for all utilities, and is considered equitable. Approaches proposed by stakeholders, the California Public Utilities Commission (CPUC), and the California Energy Commission (CEC)[25] have suggested balancing historical emissions and electricity sales to allocate allowances. By considering historical emissions, allocation can recognize the diversity of generating resources across utilities. Recent investments to reduce emissions can also be rewarded by using historical emissions that, for example, preceded the enactment of AB 32. By considering retail sales, allocation can reflect differences in the amount of electricity delivered by each retail provider. The sales metric would reward utilities that achieve lower emissions intensities, consistent with the long-term goal of reducing GHG emissions from the sector overall.

To date, staff's analyses of options based on historical emissions and sales have not identified an allocation method that provides appropriate incentives for emissions reductions and is considered affordable and effective for all utilities. The contracts for high-emitting resources pose a particular challenge. Some contracts expire as soon as 2016, providing substantial opportunity for emissions reduction prior to 2020. Other commitments run past 2020, limiting the opportunity to reduce emissions from the existing resource in the next 10 years, even as substantial investments are made to acquire new low-emitting resources. Simply considering historical emissions and sales does not adequately reflect these divergent circumstances. Also, the allocation method must avoid inadvertently providing an incentive to continue using high-emitting resources, but rather must provide incentives to ensure that all cost-effective efforts are undertaken to achieve necessary emissions reductions.

Staff is continuing to examine options and obtain feedback. With input from stakeholders, staff's analysis is examining additional factors that could be considered beyond historical emissions and sales, including, among other things, the dates of contract expirations, the rate of achievement of renewable and other low-emitting resources, incentives for early reductions in commitments for high-emitting resources, and other program design features. Staff will continue to work with stakeholders and will review comments received during the comment period on this proposal. Staff may bring a more detailed proposal to the Board

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[25] The California Public Utilities Commission and the California Energy Commission presented recommendations to ARB about the design of a cap-and-trade program for the electricity sector in October 2008. Those recommendations are included as Appendix M.

based on this ongoing effort, and will circulate any such proposal for review in a subsequent 15-day comment period.

3. Allocation of Allowances Associated with Distributed Use of Natural Gas

Beginning in 2015, natural gas distribution utilities will be responsible for the emissions associated with natural gas delivered to customers not directly covered under the cap-and-trade program, including residential, commercial, and small industrial customers. Following comparable arguments to those applied in the electric sector, the investor-owned natural gas distribution utilities have proposed allocation to the gas utilities based on the proportionate share of total capped emissions from residential and commercial natural gas use over a historical period.

Under the utilities' proposal, the allowances allocated to the sector would decline over time in proportion to overall cap decline. The utilities requested that ARB allow 90 percent of the allowances to be directly retired to reduce the utility compliance obligations, with the remaining 10 percent offered on consignment by the utility at auction. The proceeds raised from the sale of this 10 percent would be used to fund customer energy efficiency and other greenhouse gas reduction programs.

ARB is considering this proposal along with alternative approaches. One alternative would be for ARB to allocate allowances to the utilities but require them to offer all allowances on consignment at auction. Proceeds from the sale of these allowances could then be used to provide rebates to customers on a non-volumetric basis. The CPUC would determine the final amount of proceeds dedicated to rebate programs or to customer energy efficiency and other GHG-reduction programs. This treatment would be analogous to how investor-owned utilities are expected to protect their customers in the electricity sector.

Another alternative under consideration would be to have the allowances associated with emissions from dispersed natural gas combustion auctioned and the allowance value returned to customers through action by the Governor and the Legislature. This approach is analogous to how other distributed fuel use (i.e., gasoline, diesel, and propane) is treated under staff's current proposal.

J. Auction and Sale of California Greenhouse Gas Allowances

ARB staff developed its auction design proposal based on a set of objectives that were discussed with stakeholders including:

- Promoting open access to the auction.
- Ensuring fairness and transparency of the procedures.
- Minimizing administrative and transactions costs to participants.

- Promoting economic efficiency.
- Preventing manipulative behavior.
- Revealing the market valuation of allowances.
- Minimizing price volatility.
- Promoting allowance market liquidity.

Staff has carefully examined rules for auction in existing GHG emissions trading systems, and is proposing an auction design closely resembling that used in the Northeast Regional Greenhouse Gas Initiative (RGGI). Staff also continues to participate in the development of recommendations for auction design in the WCI. Preliminary WCI recommendations are consistent with most of the main design features in the ARB staff proposal.[26]

1. Timing of Allowance Auctions

The first allowance auction will take place in February 2012. The auctions will continue based on the calendar quarter for the remainder of the program. These auctions are general auctions in which covered entities, opt-in covered entities, and voluntarily associated entities may bid for allowances.

At each general quarterly auction, one-quarter of the total allowances available for auction in the budget year will be auctioned. A number of allowances from future budget years will also be auctioned. In addition to these allowances, any party with a Limited Use Holding Account in the system may offer their allowances for sale at the general quarterly auction. Any party using this "consignment" option will be paid the auction settlement price for their allowances. If any allowances offered on consignment remain unsold after the auction, ARB will transfer them back to the owners' accounts.

Three weeks after the regular quarterly auction, ARB will also offer allowances in the Reserve for sale at fixed prices to covered entities.

2. Auction Format and Reserve Price

In each auction, participants can submit bids by specifying how many allowances they want at a specific price. Allowances will be sold in 1,000 unit bundles. Participants can submit as many bids as they like, as long as they can prove to the auction operator that they can pay for allowances they win. The bids will be sealed, which means a participant does not know what price others have bid. A

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[26] Western Climate Initiative. Markets Committee Task 6: *Auction Design White Paper.* April 14, 2010. Found at: http://www.westernclimateinitiative.org/component/remository/func-startdown/231/.

sealed bid makes it difficult for participants to manipulate the auction price or collude with others to change the auction price for their mutual benefit.

The auction will be settled in a single round of bidding. The auction operator will award allowances beginning with the highest bid. The operator will award allowances to each bid in declining order until all allowances are awarded. However, the auction operator will not accept any bids below the reserve price. If the auction settlement price equals the reserve price, unsold allowances will be placed into the Reserve, or in the case of IOUs and POUs offering their allowances on consignment, back to their Limited Use Holding Accounts. Allowances placed back into the Reserve will be offered at the direct quarterly reserve sales that occur after each general auction, as described below.

The reserve price in the proposed regulation has been set at $10/metric ton for auctions in 2012. This is the same level as the price floor that was established in the Waxman-Markey cap-and-trade legislation introduced in the United States Senate in 2009[27]. Staff believes setting the reserve price at this dollar amount will send a signal to technology developers, as well as those investing in GHG offset projects. For all years following 2012, this reserve price will be increased by 5 percent plus a consumer price index. The auction reserve price is one of the components of a linked regional market program for which consistency across the individual programs is especially important. For this reason, ARB staff will work closely to evaluate this issue with other WCI jurisdictions while evaluating their programs for possible linkage. Staff may propose an adjustment to the reserve price as part of changes made to link California's program with the programs established by WCI partner jurisdictions.

3. Auction Administration and Registration

The auctions will be conducted by ARB or may be contracted to a third party that is hired by ARB to act as the auction operator. Any auction operator hired by ARB to conduct auctions will be subject to ARB oversight, and no auctions will be final until ARB approves the results. If California links with other WCI jurisdictions, then the auction operator may sell California and linked jurisdictions allowances in the same auction.

ARB will announce the auction on its website at least 60 days prior to each auction. This announcement will specify the date, time, and location of the auction; information that must be submitted to ARB by those wishing to participate in the auction consistent with the proposed regulation; and the number of allowances that will be auctioned.

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[27] American Clean Energy and Security Act of 2009, H.R. 2454, 111th United States Congress, 1st Session. (2009).

All entities wishing to participate in an auction must register for each auction at least 30 days prior to the date of the auction. The proposed regulation specifies the information each auction participant must submit to take part in the auction. The registration process allows ARB to update information on participants. ARB retains the ability to deny registration approval to any participant with a history of violating auction or market rules. Each entity must also provide a bid guarantee. A *bid guarantee* provides assurance to ARB that the purchaser of allowances at auction has the financial capability to buy them. A bid guarantee can be a bond issued by a financial institution, cash in the form of a wire transfer or certified funds, or a irrevocable letter of credit issued by a financial institution.

Staff proposes to implement a limit, known as a purchase limit, on the amount of allowances that a single entity and its affiliates are able to purchase at any single auction to ensure that all entities with a compliance obligation have fair and equitable access to allowances sold at auction. Each covered entity and opt-in covered entity can purchase of a maximum of 10 percent of the total number of allowances offered for each budget year. Each voluntarily associated entity can purchase a maximum of four percent of the total number of allowances offered at each auction. ARB believes this purchase limit, together with direct allocations to covered entities and the option to use offset credits, would allow covered entities to obtain a sufficient part of their compliance obligation at auction. In addition, ARB proposes to exempt the investor-owned utilities from the purchase limit because entities do not receive a direct allocation that they can use for their own compliance needs.

4. Direct Quarterly Sales of Allowances from the Allowance Price Containment Reserve

Staff recognizes that unforeseen events, such as a drought year that results in low hydroelectricity generation and high electricity sector emissions, could create a shortage of allowances and result in periods of high market prices. The proposed regulation includes a reserve pool of allowances to manage potential price spikes. Covered entities will have the option of buying from the reserve pool at fixed prices. The reserve allowances will not be available to voluntarily associated entities.

Sales from the Reserve will take place three weeks after each quarterly auction. Allowances in each tier can be purchased at a fixed price. Staff proposes to set these prices at $40/metric ton, $45/metric ton, and $50/metric ton. These prices will increase each year. Covered entities will place bids for the number of allowances they wish to buy from each tier. Many of the administrative procedures, such as the requirement for a bid guarantee, will be the same as for the auction. The Reserve administrator will award allowances from each tier until the tier is exhausted. Empty tiers will not be refilled. If too many bids are submitted for a tier, the Reserve administrator will prorate the available allowances to the bidders.

Purchases from the Reserve will be subject to the Holding Limit described in Section K: Trading and Banking. In addition, allowances purchased from the Reserve will be transferred by the administrator directly to the purchasing entity's Compliance Account, from which it cannot be removed until it is surrendered. Staff proposes this to ensure that allowances are only purchased to meet compliance needs, not to provide a supply of allowances for speculative activity.

5. Identifying Corporate Affiliations and Beneficial Purchases

Staff proposes to require disclosure of affiliations of registered entities, along with entities purchasing or holding instruments on behalf of another entity. These disclosures are essential to market monitoring. The information is also crucial to evaluating the purchase and holding limits when auction purchases are made.

K. Trading and Banking

Trading allowances establishes a price for each metric ton of GHG emissions. Participation of covered entities ensures the market price reflects the cost for reducing emissions per metric ton, as well as market participants' expectations of how that cost will change over time. An entity would buy an allowance if the market value of the allowance is less than the entity's cost of reducing emissions. Alternatively, an entity may sell an allowance to another entity at the current market price if it can make direct reductions at a cost lower than the allowance price. An entity that anticipates that the cost of direct reductions will be more expensive in the future may purchase and hold allowances for sale in the future.

Staff is proposing rules to prevent market manipulation, since some entities may attempt to manipulate the market for compliance instruments, as has been observed in other markets. Some rules involve information disclosures to assist in monitoring the market. Staff is also proposing prohibitions on trading activities that involve fraud, reporting false or misleading information, misrepresentations, and manipulations that are commonly used in other markets.

One prohibition in the proposed regulation deals with efforts to "corner" a market —an entity purchases such a large share of available compliance instruments that other market participants have no choice but to buy from them. To combat this tactic, staff proposes the use of a holding limit, which is the maximum share of available compliance instruments that an entity or group of affiliated entities may own. All types of registered entities will face a limit on allowances placed in their Holding Accounts, which entities use for buying and selling. Covered entities will have an exemption from the holding limit for allowances they place in their Compliance Accounts up to the amount of their most recent year's verified emissions. This exemption allows them to accumulate compliance instruments to meet their surrender obligation without violating the limit. Without this limited exemption, ARB would have to set the holding limit so high that it could not prevent hoarding. Holdings by affiliated entities will be evaluated as if they belonged to a single entity.

Transactions, such as trades or surrender of compliance instruments, are transfers of serial numbers between accounts. All transfers are accomplished through submission of a transaction report to the accounts administrator. Staff proposes that these reports include such information as account numbers and authorized account representatives of both parties, the serial numbers of instruments to be transferred, settlement and delivery dates, and price if applicable. The rules also set a time limit for reporting the transaction. The accounts administrator may reject reports if the transaction does not conform to the regulations.

California compliance instruments do not expire. This allows an entity to hold the instrument until it is needed. Staff proposes this "banking" feature to allow entities to save instruments across compliance periods. This is intended to limit price variability, as entities buy additional instruments during times of relative oversupply and use or sell them when supplies are short and prices are higher.

Allowances issued for a future year cannot be used for surrender in an earlier compliance period. The one exception is an allowance purchased from the Reserve, which may be used as soon as it is bought. This approach is proposed to prevent the threat of "cascading borrowing." This situation occurs when entities are able to use future allowances for current compliance, and it creates a growing shortage of instruments in later compliance periods.

Staff also proposes that entities without a compliance obligation may voluntarily submit allowances to ARB for retirement. The process simply requires them to submit a transaction report that names the ARB Retirement Account as the destination account for the transaction.

L. Linkage

The concept of *linkage* involves integrating one greenhouse gas emissions trading system with one or more other systems. When two cap-and-trade programs—for example, California and another WCI partner jurisdiction—recognize allowances and offsets from each other's systems, they are linked. The two systems must agree to accept allowances and offsets to meet surrender obligations interchangeably between them. If California were to link to another program, allowances could flow in both directions between California and the other system. To accomplish this in California, ARB would accept allowances or offsets issued by other approved programs to meet a compliance obligation in the California cap-and-trade program.

If California were to link, covered entities would generally use allowances and offsets from a linked program if they were less expensive than making reductions on-site or purchasing California allowances and offsets. Sources in both programs would seek out the lowest cost reductions to be found across systems, which should lead to a more liquid and better functioning market. For this reason, linkage allows for increased cost-containment by reducing the aggregate cost of

meeting the cap. While the proposed regulation establishes a framework and criteria for linkage, staff is not proposing to link to any programs at this time.

1. Evaluating Linkages

Each cap-and-trade program will have slightly different design elements. If design features exist or are later adopted into a linked program they will be made indirectly available to California participants, regardless of whether the same provisions exist in the design of the California program. Therefore, it is critical that before California links to another program, ARB evaluate the design features of a potential linked program. There must also be assurances that the program will continue to implement the agreed-upon program design moving forward.

When evaluating a program for linkage it is important to consider the implications that linkage may have on California's program, including the indirect impacts that could occur. When California establishes a linkage there may be unintended consequences for the California cap-and-trade program. These consequences could occur if the linked system makes changes to the design of its program in the future or links to another system.

2. Process for Approval of Linkages

A regulatory action by the Board will be needed to approve linkage with another program. Before a program would be brought to the Board for approval, it would undergo an analysis culminating in a separate rulemaking process. Each rulemaking process would occur prior to staff proposing regulatory amendments incorporating the linkage, and would include a public process, CEQA evaluation, and statement of reasons. The linkage section in the regulation would be amended to include specific provisions for each approved linkage.

3. Criteria for Evaluating a Program for Linkage

Following staff's evaluation of the implications of the linkage, staff would propose linkage to the Board. In evaluating whether California should link to another program, staff will consider criteria that the potential linked program must meet, as discussed below.

The potential program must be operated by a sub-national or national government that has committed to a similarly stringent binding and declining cap. That cap must also cover one or more economic sectors, such as in the California cap-and-trade program.

The key to maintaining the environmental integrity of the California cap-and-trade program is the effectiveness of its monitoring, reporting, verification, and enforcement provisions. Although, these provisions do not need to be identical, ARB needs to be confident that the linked program has provisions for monitoring, reporting, verification and enforcement that are reliable and sufficient to ensure the environmental integrity of the program.

Certain other features of a cap-and-trade program, mainly those designed to contain costs, need to be harmonized before ARB links to another program. In particular, these include cost-containment provisions such as offset credits, linkage to other programs, an auction floor price, and banking and borrowing.

The potentially linked program must contain provisions to ensure that offset credits issued by, and accepted into, its system provide the same integrity as those issued by California's program. Because the design and operation of an offset program is key to maintaining the environmental integrity in any cap-and-trade program, the potential program must have a mechanism that limits the use of offset credits in its program, similar to California's quantitative usage limit.

In addition to including similar cost-containment mechanisms, the potentially linked program must have sufficient requirements for market tracking, registration, enforcement, and information transfer. The system must have a market tracking system that is able to provide that compliance instruments, when voluntarily retired or used to meet a compliance obligation in any program, are disqualified from further use in any program. This mechanism will ensure that the same allowances and offsets are not used more than once in multiple programs.

The potentially linked program must also have a comprehensive registration requirement for all market participants and be capable of transferring information on all registrants to California's market tracking system. The program must be able to: transfer information on creation, approval, and retirement of compliance instruments; serve as a permanent repository of ownership information on all transactions involving approved compliance instruments, from the time they are created or approved to the time they are retired, including prices, those who transact compliance instruments, and other documentation; and provide a complete history of ownership of all approved compliance instruments to linked programs that may retire the compliance instruments issued, or approved for use, under its system. These requirements are necessary for ARB to be able to track the owner of a specific compliance instrument at any time, even if it did not originate in California's market tracking system.

It is important for linked programs to have a similar level of enforcement provisions as those of ARB. The potentially linked program must have an enforcement mechanism that can: provide general market surveillance; identify suspect transactions; undertake investigations and enforcement actions; ensure that consequences for noncompliance are substantially the same in all programs linked to its system; respond in a timely manner to requests by ARB for information on market participants under investigation by ARB; and transfer to ARB, in a timely manner, a complete record of all enforcement actions undertaken by the program's jurisdictional enforcement authority.

The potentially linked program must also be capable of transferring market-sensitive information necessary to monitor market trends on a regional basis, including: prices, aggregate emissions, positions of major market participants,

issuance of offset credits, and information that can be released to the public in a coordinated and consistent manner. By requiring transparency and collecting pertinent market and trading information ARB, as well as the public, can monitor and track market transactions and trends.

4. Potential Linkage with Western Climate Initiative Partners

Although California is unable to include regulatory language for linkage to programs that are still being developed, some WCI partners may be ready to implement their cap-and-trade programs in the near term.

WCI partners developed a model rule released in July 2010 called the Design for the WCI Regional Program.[28] Four other WCI Partner jurisdictions—New Mexico, British Columbia, Ontario, and Quebec—are working to implement their cap-and-trade programs by January 2012. Although these partner jurisdictions have not finalized their programs, staff has been working closely with them and is confident that these partners are moving forward with cap-and-trade programs generally consistent with the Design for the WCI Regional Program. As these programs move closer to implementation, staff will evaluate them and return to the Board with recommendations for linkage.

Staff is looking to link with WCI partner programs for several reasons, including:

- Achieving greater emissions reductions and improving the cost-effectiveness of the program by including additional low-cost emissions-reduction opportunities throughout the region.
- Reducing the risk of emissions leakage and maintaining competitiveness by expanding the geographic coverage.
- Improving market liquidity and reducing market volatility and manipulation by enlarging the supply of compliance instruments.

Linkage provisions adopted through a separate regulatory process would need to specify how the cap limits would be adjusted to include linkage to WCI partner jurisdictions where California is an importer of electricity. Currently, the proposed regulation accounts for emissions of imported electricity in the allowance budgets. To prevent double-counting of these emissions, California would have to subtract these emissions from cap levels in the case of future linkages. In this case, ARB would specify in the approval of linkage the equivalent number of allowances that

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[28] *Design for the WCI Regional Program.* Western Climate Initiative, July 27, 2010. Found at: http://westernclimateinitiative.org/component/remository/general/program-design/Design-for-the-WCI-Regional-Program/.

would need to be retired in the California system to account for the emissions of imported electricity from the linked jurisdiction.

New Mexico's proposed regulation[29] varies from the Design for the WCI Regional Program in a number of areas, including not accounting for emissions associated with imported electricity. AB 32 requires ARB to account for emissions associated with imported electricity and to minimize leakage. Staff plans to work closely with New Mexico and the relevant utilities to determine what can and should be done to allow California to appropriately account for imported electricity. If an appropriate mechanism can be developed and implemented, and all other aspects of New Mexico's program are acceptable for linkage, ARB staff would be able to recommend to the Board that California's program should link with New Mexico's program.

M. Offset Credits Issued by ARB

Individual projects can be developed to achieve GHG reductions from activities not otherwise regulated or covered under the cap-and-trade program. These projects, called *offset projects*, can generate offsets, or verifiable emissions reductions whose ownership can be transferred to others, including entities with a compliance obligation under a cap-and-trade program. In addition to providing compliance flexibility, the inclusion of offsets in the program will support the development of innovative projects and technologies from sources outside capped sectors that can play a key role in reducing emissions both inside and outside California.

As required by AB 32, any reduction of GHG emissions used for compliance purposes must be real, permanent, quantifiable, verifiable, enforceable, and additional (HSC §38562(d)(1) and (2)). Offsets issued by ARB must be quantified according to Board-adopted methodologies. The proposed regulation includes provisions to verify and enforce the reductions incentivized through the generation and retirement of offset credits. The regulatory criteria for compliance offsets will ensure that the reductions are quantified accurately and are not double-counted within the system.

Staff recognizes that a robust supply of offset credits can help to contain the costs of a cap-and-trade program. To promote the supply of offset credits, staff proposes that: (a) ARB issues offset credits for projects using ARB-approved protocols, and (b) ARB recognizes offset credits from ARB-approved offset programs. These programs could include sectoral programs such as those reducing emissions from deforestation and forest degradation in developing

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[29] Proposed Greenhouse Gas Cap-and-Trade Program, New Mexico Environment Department. (2010). Found at: http://www.nmenv.state.nm.us/cc/CapandTradeRegulation.htm.

countries (REDD). Offset credits from linked programs (such as WCI partner jurisdictions) would also be eligible for use in California's cap-and-trade program. ARB staff incorporates provisions in the proposed regulation to allow these two methods to be used following Board approval of specific protocols or programs.

The proposed regulation includes provisions to specify requirements for third-party verifiers, offset project developers, and offset credit users, as well as penalties for noncompliance. Since offset projects can be located outside of California, all offset credits must be verified by an ARB-accredited verifier, and ARB has the ability to audit all accredited verifiers. Offset verification procedures in the proposed program are designed to reduce subjectivity and uncertainty. These procedures help ensure the rigor and validity of offset credits. The offsets verification program requires that verifiers demonstrate competence in each specific project type, employ conflict of interest assessments and mitigation requirements, and include random verifier audits and strict performance evaluations to ensure that offset verification activities are conducted accurately and properly. The program's underlying registry system for compliance instruments is being designed to provide strong enforcement capabilities, including mechanisms to prevent double-counting, impose public disclosure requirements, and ensure ownership.

For offset credits issued by ARB, all offset protocols used in the compliance program must be adopted by the Board. The proposed regulation establishes the process by which the Board will approve and amend offset protocols based on staff's evaluation and a public process. These protocols will be made publicly available so that anyone interested in developing an offset project can do so according to Board-approved standards. Approved protocols serve as a cornerstone to ensure that reductions are appropriately quantified, monitored, reported, and documented. Those taken to the Board for adoption will consist of standardized methods that quantify reductions based on specific criteria and pre-established calculation methods. This approach will result in streamlining the calculation of project baselines and determining the additionality of projects using standard eligibility criteria that ensure projects are additional.

Staff has developed four compliance offset protocols, which can be found in Parts II through V of the Staff Report, for use under the compliance offset program. These protocols include the U.S. Forest Projects Protocol, the Livestock Manure (Digester) Projects Protocol, the Urban Forest Projects Protocol, and the U.S. Ozone Depleting Substances Projects Protocol. They are incorporated by reference in the proposed regulation and are being considered for adoption by the Board as part of this rulemaking package. While the program contains provisions to allow offset projects from North America, staff is only taking offset protocols applicable in the United States to the Board for approval as part of this rulemaking package.

ARB has coordinated with the other WCI partner jurisdictions in developing the offset program, including identifying specific project types for first priority and a

review of existing protocols for those project types.[30] While ozone-depleting substances projects were not included in this priority review, ARB considers it to be a promising offset project type. The WCI partner jurisdictions are currently reviewing this protocol, including assessing it relative to the WCI offset criteria recommendations. Staff will continue to work within WCI to address any issues that may arise with use of this protocol in the context of linking with a WCI partner.

To ensure that there is a ready supply of offset projects developed according to Board-approved protocols, staff proposes to work with qualified third-party offset programs to bring offset credits from new offset projects into the offset program. Staff recognizes that third-party offset programs have existing capabilities and infrastructure that can be deployed quickly to enhance the supply of offset credits. The proposed regulation includes conditions and processes under which third-party programs can be approved to generate offset credits for compliance use according to ARB-approved protocols.

The proposed regulation establishes requirements for offset projects that want to be issued offset credits. These include using a Board-approved protocol, meeting the requirements for additionality, being located in North America, and complying with all applicable laws and regulations at the national, state or provincial, and local levels.

The proposed regulation requires that project developers "list" their projects (i.e., submit information pertaining to their offset projects). *Listing* establishes a mechanism for project developers to record information on their offset projects for ultimate issuance of offset credits. Project listing requires the submittal of information on each project for transparency purposes. The requirements for what information must be submitted can be found for each type of offset project in the corresponding offset protocol, which are incorporated by reference in the proposed regulation. When listing, project developers must also attest to ARB that all information they submit for listing purposes is truthful and accurate. These attestations will be used for enforcement purposes.

Monitoring requirements in the proposed regulation include measurement and data collection for key project parameters, as well as related procedures and quality control procedures. The monitoring requirements address questions regarding what needs to be measured, how often, and acceptable methods and instrumentation for data collection. The staff proposal requires measurement

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[30] Det Norske Veritas. *Review of Existing protocols Against WCI Offset Criteria.* For the Western Climate Initiative. April 2010. Found at: http://www.westernclimateinitiative.org/component/remository/Offsets-Committee-Documents/WCI-Review-of-Existing-Offset-Protocols.

device calibration according to the manufacturer's recommended procedures. General monitoring requirements can be found in the proposed regulation, while specific requirements for each type of offset project can be found in the individual protocols. Protocol-specific monitoring requirements increase consistency among projects of the same type and allow monitoring requirements to be tailored to each project type.

The proposed regulation requires reporting on the performance of offset projects, including a process for summarizing project monitoring data, calculating the GHG reductions achieved in the applicable period, and documenting that information in a project report. The required content and level of detail demanded in project reports, referred to as *Offset Project Data Reports* in the proposed regulation, vary between project types.

In the proposed regulation, staff includes requirements for a verification program that are consistent with international standards and subject to ARB oversight. This oversight includes verifier accreditation, verification body accreditation, requirements for verification services, and conflict-of-interest requirements. The proposed regulation includes enforcement provisions that apply to parties that participate in the offset program. These parties include offset project developers, verifiers, and covered entities.

The proposed regulation establishes a Forest Buffer Account—a permanence mechanism for ensuring that GHG emissions remain out of the atmosphere—to replace offset credits in the event of an unintentional reversal. The Forest Buffer Account acts as an insurance policy; the developer pays a premium up front to be fully covered later in the event of a loss. A portion of all offset credits issued to offset projects developed according to ARB's U.S. Forest Projects Protocol must be placed into the Forest Buffer Account to cover unintentional reversals. The forest project operator is required to follow the methods in the U.S. Forest Projects Protocol for calculating the project's risk rating. The risk rating is based on a number of default and calculated factors that differ, depending on the individual project. The factors and equations that must be used to determine each project's risk rating are provided in the U.S. Forest Projects Protocol.

To ensure enforceability of compliance offsets, ARB needs to have the ability to investigate and take action for violations or noncompliance with the regulations. There are two primary reasons that ARB may need to invalidate offset credits after they have been issued: (1) fraud or malfeasance on behalf of the project developer, the third-party verifier, verification bodies, or others involved in producing the documentation used to support the issuance of offset credits, or (2) a reversal in the forest sector. If an offset credit is invalidated and has been used for compliance or retired, it must be replaced. If the offset credit has already been retired, staff is proposing, in all cases of fraud or malfeasance, that the entity that used or retired it be responsible for replacing any invalidated offset credits. The covered entity may then take appropriate action through third-party contractual arrangements they may have established prior to purchase. In the

event that the offset credit has not yet been used or retired, it will be canceled in the market tracking system and removed from any Holding or Compliance Accounts. If there is an unintentional reversal in the forest sector, staff will deduct the necessary amount of offset credits from the Forest Buffer Account and retire them, whether or not they have been used or retired within the system. If there is an intentional reversal in the forest sector, staff proposes that the forest project developer replace the invalidated offset credits, whether or not they have been retired within the system.

N. Recognition of Compliance Instruments from Other Programs

1. Early Action Offset Credits

The proposed regulation includes a process for accepting offset credits from qualified existing offset projects into the ARB compliance offsets program to help create an initial supply of offset credits for the cap-and-trade program. Beginning in 2005, the Climate Action Reserve (CAR) and its predecessor, the California Climate Action Registry, began adopting voluntary GHG accounting protocols to encourage voluntary early action to reduce GHG emissions. ARB recognizes the rigor of the voluntary accounting procedures CAR adopted to establish that GHG emissions reductions are real, additional, and permanent. Staff proposes to allow eligible offset credits and ongoing projects under protocols developed for four project types to transition into ARB's compliance offset program. These project types are the four for which protocols are proposed for adoption as part of the cap-and-trade regulation: (1) U.S. Forest Projects, (2) Urban Forest Projects, (3) U.S. Ozone Depleting Substances Projects, and (4) Livestock Manure (Digesters) Projects.

Staff includes requirements in the proposed regulation that an offset program must meet in order to have its early action offset credits used for compliance purposes.

2. Sector-Based Offset Crediting Mechanisms

The regulation establishes a framework for accepting sector-based offset credits from developing countries. While staff is not proposing to approve any sector offset crediting programs or adopt any protocols for sector-based offset credits at this time, this framework should help provide a necessary incentive for developing countries to reduce their emissions and work toward meeting compliance-grade, sector-based offset credit requirements in California.

Each sector-based crediting program will need to be approved by the Board, and staff anticipates that a limited number of sector-based programs will be approved in the near-term because of the intensive review each program will undergo. Staff also proposes that the first sectors to be considered for approval be developed through existing partnerships, such as the Governors' Climate and Forests Task Force (GCF) and the International Carbon Action Partnership (ICAP). To that end, Reducing Emissions from Deforestation and Forest Degradation (REDD) is likely to be the first type of sector-based crediting

program brought to the Board for consideration, as is discussed in more detail in Chapter III: Overview of the Compliance Offsets Program.

Some general requirements have been proposed in the regulation that sector-based crediting programs should meet before being considered by the Board, but more detailed criteria and methodologies must be established for each sector prior to Board approval and acceptance of sector-based credits.

O. Enforcement and Penalties

ARB has authority in existing Health and Safety Code provisions to enjoin and set penalties for violations of its regulations. As such, staff has established in the proposed cap-and-trade regulation violations unique to the cap-and-trade program. These include defining a separate violation for each compliance instrument for each day that has not been surrendered as required, and a separate violation for each day or part of a day for which any other part of the regulation has been violated.

1. Jurisdiction

Staff recognizes that not all participants in the California cap-and-trade program will be located in California. The regulation contains a list of activities involved in the cap-and-trade program that would establish the jurisdiction of California over the entity. These include: registration, the purchase or holding of a compliance instrument issued by ARB, verification of an offset to be issued by ARB, or the receipt of any form of compensation resulting from participation in the transfer of allowances or offsets issued by ARB.

2. Authority to Suspend, Revoke, or Restrict Accounts or to Modify an Executive Order

In addition to conventional penalties, staff proposes that ARB may limit the ability of a registered entity to fully participate in the market as a response to violations by the entity. For voluntarily associated entities, staff proposes that the Executive Officer be able to suspend, revoke, or place transaction restrictions on the Holding Accounts of violators. For covered entities, staff proposes that the Executive Officer be able to place transaction restrictions on the Holding Accounts of violators. Staff also proposes that the Executive Officer be able to revoke the registration of entities in the Other Registered Participants category if they violate the regulations. Finally, staff proposes that the Executive Officer be able to suspend, revoke, or modify an existing Executive Order in response to violations by an entity.

P. AB 32 Requirements

AB 32 contains standards that apply to regulations that will be adopted for all GHG emissions-reduction measures (HSC section 38562) and additional requirements for market-based regulations such as a cap-and-trade program (HSC section 38570(b)). AB 32 also calls for ARB to direct public and private investment to the extent feasible toward disadvantaged communities and provide

an opportunity for small business, schools, affordable housing associations, and other community institutions to participate in and benefit from statewide efforts (HSC section 38565). AB 32 further requires that the GHG reductions be real, additional, permanent, quantifiable, verifiable, and enforceable.

The cap-and-trade program was developed in accordance with these AB 32 requirements, and this Staff Report presents supporting details. The following provides a brief response to each of the specific requirements set forth in sections 38562(b), 38562(d), and 38570(b) of the Health and Safety Code. The text in italics is verbatim from the particular section.

38562(b) In adopting regulations pursuant to this section and Part 5 (commencing with Section 38570), to the extent feasible and in furtherance of achieving the statewide greenhouse gas emissions limit, the state board shall do all of the following:

> *(1) Design the regulations, including distribution of emissions allowances where appropriate, in a manner that is equitable, seeks to minimize costs and maximize the total benefits to California, and encourages early action to reduce greenhouse gas emissions.*
>
> Staff has designed the proposed cap-and-trade program, including the allowance allocation system, to minimize the cost of implementation and compliance and to maximize the overall benefits. The allowance allocation system is equitable within and across sectors of the California economy, and its primary reliance on efficiency benchmarks and auction encourages early action to reduce emissions. In addition, the ability to bank allowances for future use provides an incentive for early action to reduce emissions.
>
> By ensuring that most GHG emissions in California are covered by the program, and that incentives are in place to ensure that the most cost-effective reductions are made, the program design shares the emissions-reduction burden equitably.
>
> *(2) Ensure that activities undertaken to comply with the regulations do not disproportionately impact low-income communities.*
>
> Staff has evaluated both the health and economic effects of the proposed program to ensure, to the extent feasible, that no disproportionate negative impact will occur in low-income communities. The overall health and environmental effects of the regulation are expected to be positive, and the program has been designed to minimize any economic costs that might affect low-income communities.
>
> *(3) Ensure that entities that have voluntarily reduced their greenhouse gas emissions prior to the implementation of this section receive appropriate credit for early voluntary reductions.*

ARB staff has recommended a system for distributing allowances in the industrial sector that will primarily rely on efficiency benchmarks for any free allocation. This type of approach rewards those who have already invested in emissions reductions. In addition, a portion of the allowances will be auctioned, and those who have taken early action will be less reliant on purchasing allowances at auction. This allowance allocation system provides appropriate credit for those who have taken steps to voluntarily reduce their emissions before the start of the cap-and-trade program.

(4) Ensure that activities undertaken pursuant to the regulations complement, and do not interfere with, efforts to achieve and maintain federal and state ambient air quality standards and to reduce toxic air contaminant emissions.

The proposed regulation is not expected to adversely affect federal or State ambient air quality standards. This issue has been analyzed and the results are provided within Chapter VI: Environmental Impacts of the Proposed Regulation, which summarizes the environmental analysis of the proposed regulation. In addition, staff analyzed the potential effect of the cap-and-trade program on air pollutant emissions, as discussed in Chapter VII: Co-Pollutant Emissions Assessment. California's existing programs to meet federal air quality standards will provide substantial emissions reductions. Staff's analysis indicates that the effect of the cap-and-trade regulation on criteria and toxic emissions is expected to be small compared to the emissions reductions resulting from California's existing programs to meet federal air quality standards.

(5) Consider cost-effectiveness of these regulations.

The flexibility of the cap-and-trade program, together with specific design features included in the regulation to help contain costs, ensures that the reductions needed to meet the requirements of the regulation will be cost-effective. Staff estimates that the allowance prices in the program, which provide a measure of the marginal cost of emissions reductions needed to comply, will be between $15 and $30 per metric ton in 2020. See Chapter VIII: Economic Impacts of the Proposed Regulation for a detailed discussion.

(6) Consider overall societal benefits, including reductions in other air pollutants, diversification of energy sources, and other benefits to the economy environment and public health.

The cap-and-trade program is a key element of the overall Scoping Plan strategy to scale back California's greenhouse gas emissions to 1990 levels by 2020, reduce our dependence on fossil fuels, stimulate investment in clean and efficient technologies, and improve air quality and

public health. By establishing an overall limit on GHG emissions, the program establishes the price signal needed to drive long-term investment in cleaner and more efficient types of fuels and energy sources, while affording covered entities flexibility to seek out and implement the most cost-effective options to reduce emissions. The program will also complement and support California's existing efforts to reduce criteria and toxic air pollutants.

(7) Minimize the administrative burden of implementing and complying with these regulations.

The proposed regulation will require a market tracking system (MTS) to record information about the holders of compliance instruments and trades of compliance instruments among market participants. The primary goal of the MTS will be to support the effective implementation of the cap-and-trade regulation and to reduce the costs and administrative burden associated with long-term cap-and-trade responsibilities.

The cap-and-trade program will also rely on a revised version of the Mandatory Reporting Regulation (MRR) as the primary mechanism for emissions reporting. A set of revisions to the MRR are being proposed by ARB staff concurrently with the proposed cap-and-trade regulation. These revisions are intended to align California's reporting requirements with the federal reporting rules recently enacted by U.S. EPA, and to ensure that the information collected by those covered by the cap-and-trade program is of sufficient quality to support the market program.

These requirements have been designed to strike a balance between the need for transparency in this new market and the need to minimize the administrative burden on those covered by the regulation and on ARB staff.

(8) Minimize leakage.

Staff proposes an allocation approach designed to minimize leakage and to give businesses and industries in the State sufficient time to reduce their emissions in a cost-effective manner. Allocating the allowances for free to industrial sources using emissions efficiency benchmarks will reward companies that have already made investments in energy efficiency and carbon reductions, and will benefit those that continue to produce goods in California.

(9) Consider the significance of the contribution of each source or category of sources to statewide emissions of greenhouse gases.

The cap-and-trade program has been designed to cover all emission sources for which adequate quantification of the emissions is sufficient to include in a market program. The program design exempts small sources

from direct coverage in the program by establishing an emissions threshold for inclusion of 25,000 $MTCO_2e$. However, because transportation fuels and use of natural gas by residential and commercial users is a significant portion of California's overall GHG emissions, the emissions from these sources are covered indirectly through the inclusion of fuel distributors.

38562(d) Any regulation adopted by the state board pursuant to this part or Part 5 (commencing with Section 38570) shall ensure all of the following:

(1) The greenhouse gas emission reductions achieved are real, permanent, quantifiable, verifiable, and enforceable by the state board.

The Mandatory Report Regulation is being revised to ensure that all reported data for sources in the cap-and-trade program provide the high quality data needed for a market-based program. This will ensure that any emissions reductions at covered sources will be real, permanent, quantifiable, verifiable, and enforceable.

The offsets portion of the cap-and-trade program also includes extensive requirements to ensure that any credits for offset projects are limited to emissions reductions or removals that are real, permanent, quantifiable, verifiable, and enforceable.

(2) For regulations pursuant to Part 5 (commencing with Section 38570), the reduction is in addition to any greenhouse gas emission reduction otherwise required by law or regulation, and any other greenhouse gas emission reduction that otherwise would occur.

The cap-and-trade program does not require specific emissions reductions from any sources, but instead places an overall limit on the emissions that are allowed by the covered sources. Because the emissions reductions from other Scoping Plan measures are insufficient to reduce emissions below the cap level, the cap-and-trade program will require emissions reductions in addition to those otherwise required by law or regulation.

(3) If applicable, the greenhouse gas emission reduction occurs over the same time period and is equivalent in amount to any direct emission reduction required pursuant to this division.

The cap-and-trade program places a limit on emissions from 2012 through 2020, and will require emissions reductions from those sources covered by the program over that time period. Other measures adopted under AB 32 are designed to get emissions reductions over the same time period to help achieve AB 32's emissions target for 2020.

AB 32 allows market-based mechanisms, such as a cap-and-trade program, to help meet the statewide GHG emissions-reduction goals.

Market mechanisms are used to supplement, rather than replace, direct regulation approaches. The purpose of using alternate compliance mechanisms is to accomplish AB 32's environmental goals in the most cost-effective way.

38570(b) Prior to the inclusion of any market-based compliance mechanism in the regulations, to the extent feasible and in furtherance of achieving the statewide greenhouse gas emissions limit, the state board shall do all of the following:

(1) Consider the potential for direct, indirect, and cumulative emission impacts from these mechanisms, including localized impacts in communities that are already adversely impacted by air pollution.

Staff's analysis of the potential for direct, indirect, and cumulative emissions impacts, including localized impacts in communities that are already adversely impacted by air pollution, is discussed in Chapter VII: Co-Pollutant Emissions Assessment. Staff's analysis indicates that the cap-and-trade regulation is expected to have a beneficial impact on emissions overall. California's existing programs to meet federal air quality standards will provide the majority of emissions reductions through 2020. The regulation has the potential to provide additional NO_x reductions if all greenhouse gas reductions are implemented locally, even without consideration of the criteria pollutant and toxic emissions reductions that the cap-and-trade program is expected to provide from transportation fuels and commercial and residential gas use. While the flexibility inherent in the cap-and-trade program could allow some facilities to increase GHG emissions, any related criteria or toxic emissions increases at these facilities would mean a smaller decrease in local emissions in 2020 when the existing air quality programs are taken into account. The cap-and-trade program will provide an incentive for covered facilities to decrease greenhouse gas emissions and any related emissions of criteria and toxic pollutants.

(2) Design any market-based compliance mechanism to prevent any increase in the emissions of toxic air contaminants or criteria air pollutants.

ARB's analysis indicates that the cap-and-trade regulation is expected to have a beneficial impact on air emissions by reducing emissions of criteria pollutants and toxics. As discussed in Chapter VII: Co-Pollutant Emissions Assessment, based on the available data, current law and policies that control industrial sources of air pollution, and expected compliance responses, ARB believes that emissions increases due to the regulation at the statewide, regional, or local level are extremely unlikely, at best. Nevertheless, as described in Section Q: Program Monitoring, ARB is committed to monitoring the implementation of the cap-and-trade

regulation to identify any situations where the cap-and-trade program has led to an increase in criteria pollutant or toxic emissions.

(3) Maximize additional environmental and economic benefits for California, as appropriate.

The cap-and-trade program is a key element of the overall Scoping Plan strategy to scale back our greenhouse gas emissions to 1990 levels by 2020, reduce our dependence on fossil fuels, stimulate investment in clean and efficient technologies, and improve air quality and public health. By establishing an overall limit on the GHG emissions, the program establishes the price signal needed to drive long-term investment in cleaner and more efficient types of fuels and energy sources, while affording covered entities flexibility to seek out and implement the most cost-effective options to reduce emissions. The program will also complement and support California's existing efforts to reduce criteria and toxic air pollutants.

Staff's evaluation of the cap-and-trade program is consistent with these requirements of AB 32. In addition, the evaluation is consistent with ARB's Environmental Justice Policy adopted by the Board in 2001.[31] State law defines environmental justice as the fair treatment of people of all races, cultures, and incomes with respect to the development, adoption, implementation, and enforcement of environmental laws, regulations, and policies.[32] ARB is committed to making environmental justice an integral part of its activities. The Board approved its Environmental Justice Policies and Actions (Policies) on December 13, 2001, to establish a framework for incorporating environmental justice into ARB's programs consistent with the directives of State law. These policies apply to all communities in California, but recognize that environmental justice issues have been raised more in the context of low-income and minority communities.

As part of the economic, emissions, and environmental assessment of the cap-and-trade regulation, staff assessed the emission reduction opportunities available to sources covered by this regulation. This evaluation considered the potential for the incentives and flexibility inherent in the cap-and-trade program to result in direct, indirect, and cumulative emission impacts, including localized impacts in communities that are already adversely impacted by air pollution. Based on the available data and current law and policies that control

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[31] http://www.arb.ca.gov/ch/programs/ej/ejpolicies.pdf

[32] Senate Bill 115 (Solis, Statutes of 1999, chapter 690); California Government Code § 65040.12(c)

localized air pollution, and expected compliance responses to the cap-and-trade regulation, ARB concludes that, increases in localized air pollution, including toxic air contaminants and criteria air pollutants, attributable to the cap-and-trade program are extremely unlikely. For more information see Chapter VII. Co-Pollutant Emissions Assessment and Appendix P: Co-Pollutant Emissions Assessment.

Q. Program Monitoring

The cap-and-trade program is made up of many elements, must serve a large number of important objectives at the same time, and relies on the cumulative actions of a large number of participants operating in a complex market system. Accordingly, unanticipated effects and results could occur over the life of the program. ARB will monitor the program to ensure that it is achieving emissions reductions and other AB 32 objectives and is not resulting in unanticipated outcomes. ARB is committed to review and revise policies, protocols, and procedures as more information becomes available.

Once the cap-and-trade program is implemented, ARB will monitor whether, over time, the program is meeting all of the objectives set forth in AB 32. These objectives include certain beneficial outcomes that should be maximized, and also certain adverse consequences that should be minimized or avoided.

Using the results of monitoring, ARB will regularly (at a minimum, once every three-year compliance period) evaluate whether the objectives identified by statute are being achieved. Periodic evaluation will be coordinated with other actions and information-collection occurring at the end of compliance periods.

ARB will conduct its evaluation sufficiently in advance of the end of each compliance period to allow ARB sufficient time to adjust the cap-and-trade program, if warranted, before commencement of the next compliance period. If ARB determines during its periodic review that the cap-and-trade program is not achieving the objectives as defined by AB 32, or if substantial, unanticipated adverse environmental effects are identified, ARB will revise the operation of the program accordingly.

ARB has designed the regulation to avoid unintended consequences. However, given the complexity of the program, it is important to incorporate systems to monitor and evaluate the performance of the cap-and-trade program. ARB proposes to monitor emissions leakage, the generation and use of offset credits, and the potential for emissions increases to ensure that the program continues to meet the diverse objectives described in Health and Safety Code sections 38562(b) and 38570(b) over time.

1. Achieving the Greenhouse Gas Limit

At its core, the cap-and-trade regulation sets a limit on greenhouse gas emissions. ARB ensures that the cap is met by distributing a limited number of allowances to emit greenhouse gases. At the end of each three-year compliance

period, ARB will determine whether the limit has been met by examining whether the number of compliance instruments turned in by covered entities matches the emissions reported under the Mandatory Reporting Regulation plus the allowable number of offsets. ARB will post the results of its evaluation on its website or otherwise make this information publicly available.

The regulation requires entities that do not meet their compliance obligation by the deadline to turn in additional allowances, and provides for enforcement actions against covered entities that do not meet their obligations. If these mechanisms are not sufficient to ensure that the cap is met, ARB will reevaluate the regulation to strengthen these provisions.

ARB will also monitor both the price that is bid to purchase allowances at the quarterly auctions and the price at which allowances are bought and sold on the secondary market to determine whether the market is functioning as expected. Monitoring the price and the status of bids for allowances in the Allowance Price Containment Reserve will also help alert ARB staff to price increases and the need to determine whether these increases are due to legitimate unforeseen events or market manipulation.

2. Detecting Market Manipulation

ARB has collaborated closely with numerous experts to craft regulatory requirements that will provide the means to identify and ultimately prevent market manipulation. However, as with any regulation, we cannot guarantee that all regulated parties will abide by the letter and the spirit of regulatory requirements. Because of this issue, the regulation proposes registration of all market participants to ensure that third-party participants can be vetted; and requires disclosure of affiliates for whom allowances are owned ("beneficial holdings"), to help identify potential collusion or other forms of market manipulation. If market manipulation or other illicit activities are detected, ARB will work with the appropriate authorities to initiate enforcement activity and, if necessary, reevaluate regulatory requirements to avoid future incidents.

3. Leakage

ARB has designed the regulation to minimize leakage by placing covered entities on an equal footing with their non-covered competitors (both those that are out-of-state, and those that are below the threshold for inclusion in the program), and ARB is committed to monitor how covered sectors address carbon costs once the program is in place. The focus of this monitoring will be on whether industries in a sector increase their product price in response to the carbon cost, whether or not the price increase (or inability to increase the price) led to a change in market share for the covered entities, and the relative share of the California market served by in-state production and by imports. ARB staff will also work with covered sources and other interested parties to identify additional sources of information at the state level that could improve ARB's ability to monitor leakage. Should ARB find that leakage is occurring despite the

safeguards in the regulation, ARB will examine mechanisms to address leakage, including border adjustments or changes to the allowance distribution system.

4. Offset Projects

The regulation proposes a robust monitoring program for offset projects—both the verification that the offsets are real, additional, and enforceable, and that Offset Project Operators, verifiers, and Offset Project Registries are operating according to regulatory requirements. Offset Project Registries are required to conduct oversight of their registry program and randomly audit verifications to ensure that ARB regulatory requirements are being met by Offset Project Operators and verification bodies. ARB will have a rigorous oversight of its approved Offset Project Registries. Each year, the Offset Project Registries will provide ARB with a report providing basic information related to any offset project listed using a Compliance Offset Protocol and any findings related to verification audits. ARB will make this report publicly available. The Offset Project Registries will be required to provide any information related to an offset project when requested by ARB as part of its oversight of the Offset Project Registry. During the course of an offset project, the Offset Project Registry will track and report any guidance or information provided to an Offset Project Operator related to a compliance offset project to ARB every month. This will ensure that ARB understands any issues or concerns related to its compliance offset program as Offset Project Operators are implementing the actual offset projects.

In addition, the ARB regulatory offset verification program is designed to provide a transparent process by which ARB can review verification documents and fully understand any findings uncovered during the course of verification of an offset project by an ARB accredited verification body. ARB will also develop an audit and oversight program for offset project verifications.

5. Offset Protocols

Offset protocols include several elements to support existing health and environmental protection measures. Specifically, each individual offset protocol requires all offset projects to be developed in compliance with all federal, state, and local laws, regulations, ordinances, and any other legal mandate, including all CEQA and National Environmental Policy Act (NEPA) requirements where applicable. The Offset Project Operator is required to attest to ARB that their offset project meets these requirements. If, during verification, it is found that the offset project does not meet any of these requirements, the project is ineligible to be issued ARB offset credits until the project is in compliance. In addition to regulatory compliance, during project listing, Offset Project Operators must provide detailed project information, which must be posted on the Internet and available for public review.

Because of the possibility that forest projects could unintentionally "reverse," negating the benefits of those projects because of fire, pest infestation, or disease, ARB is requiring the creation and maintenance of a Forest Buffer Account to be populated by a percentage of ARB-issued offset credits from forest

offset projects. ARB will regularly monitor the number of offset credits in this Buffer Account to ensure it is sufficient to offset unintentional reversals. If the Buffer Account is found to be insufficient, ARB will revisit the contribution required by forest offset projects to this account.

Even with these safeguards, ARB recognizes that there could be unanticipated impacts from offset projects. ARB will monitor and assess offset project documentation and potential impacts from offset project implementation at a minimum of once each compliance period. In the event that unintended impacts are identified during this review, and they are substantial enough to interfere with or undermine the achievement of the objectives for the cap-and-trade program as defined by AB 32, including the objectives set forth in 38562(b) and 38570(b), ARB would develop and implement appropriate responses to rectify identified health or environmental effects. Potential responses ARB would consider, if warranted, include, but are not limited to, revising the types and/or geographic location of offset projects and disallowing the use of some types of offset credits. These potential future responses are not, however, warranted based on currently available information, and their imposition today would unnecessarily conflict with AB 32's other objectives. Monitoring of the implementation of the U.S. Forest Projects Protocol is further discussed in the Adaptive Management section of Appendix O: Functional Equivalent Document.

6. Emissions Increases

ARB's analysis indicates that the cap-and-trade regulation is expected to have a beneficial impact on air emissions by reducing emissions of criteria pollutants and toxics. Based on the available data, current law and policies that control industrial sources of air pollution, and expected compliance responses, ARB believes that emissions increases due to the regulation at the statewide, regional, or local level are extremely unlikely, at best.[33] Nevertheless, ARB is committed to monitoring the implementation of the cap-and-trade regulation to identify any situations where the cap-and-trade program has led to an increase in criteria pollutant or toxic emissions.

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[33] Not all emissions increases at facilities covered by the cap-and-trade program will result from the program itself. The cap-and-trade program will place a new regulatory requirement and a new cost on GHG emissions from all covered facilities, so that the program provides an incentive to minimize increases or to decrease GHG emissions and any related emissions of criteria or toxic emissions. While the program provides flexibility that could allow increased production due to economic growth, such increases would not be caused by the cap-and-trade program. Staff believes that only in very limited circumstances would a localized emissions increase be the actual result of the incentives created by the cap-and-trade program (e.g., shifting of production within a company from an inefficient facility with higher compliance costs to a more efficient facility that results in higher emissions at the more efficient facility).

As discussed in the Adaptive Management section of Appendix O: Functional Equivalent Document, at least once each compliance period, ARB will use information collected through the mandatory reporting regulation, the cap-and-trade regulation, the industrial efficiency audit, and other sources to evaluate how facilities are complying with the cap-and-trade regulation. ARB will also solicit information from local air districts regarding permit modifications and new permit applications for covered sources. This information will be used to identify compliance activities that could lead to increased emissions and to determine whether further investigation of potential criteria pollutant and toxic emissions is warranted.

If unanticipated adverse localized emissions impacts that can be attributed to the cap-and-trade regulation are identified during this periodic review, ARB will consider whether these impacts affect the achievement of the program objectives. If so, ARB will promptly develop and implement appropriate responses. Potential responses ARB would consider include, but are not limited to, using allowance value from the cap-and-trade program to mitigate localized emissions increases, providing incentives for energy efficiency and other emissions-reduction activities within the community, or restricting trading or prohibiting certain compliance responses in specifically identified communities. These potential future responses are not, however, warranted based on currently available information, and their imposition today would unnecessarily conflict with AB 32's other objectives.

III OVERVIEW OF THE COMPLIANCE OFFSETS PROGRAM

A. Offset Credits Issued by ARB

Individual projects can be developed to achieve GHG reductions from activities not otherwise regulated or covered under the cap-and-trade program. These projects can generate offset credits, or verifiable emissions reductions whose ownership can be transferred to others, including entities with a compliance obligation under the cap-and-trade program. In addition to providing compliance flexibility, the inclusion of offset credits in the program will support the development of innovative projects and technologies from sources outside capped sectors that can play a key role in reducing emissions both inside and outside California. Offset projects can reduce emissions, thereby generating offset credits that can be used by entities who must comply with the program. The use of an offset credit allows a covered entity to forgo some amount of on-site reductions by offsetting emissions elsewhere. Therefore, the integrity of the offsets program is crucial to achieving the AB 32 goal.

As required by AB 32, any reduction of GHG emissions used for compliance purposes must be real, permanent, quantifiable, verifiable, enforceable, and additional (HSC §38562(d)(1) and (2)). Offset credits issued by ARB must be quantified according to Board-adopted methodologies. The proposed regulation includes provisions to verify and enforce the reductions incentivized through the generation and retirement of offset credits. The criteria for compliance offset credits will ensure that the reductions are quantified accurately and are not double-counted within the market tracking system.

Offset credits can provide covered entities a source of low-cost emissions reductions. Reductions achieved through the offset program must be measured using rigorous quantification methods. Offset protocols provide a basis to determine whether offset projects are also additional. Establishing that offset projects are additional is one of the most important factors for the validity of individual offset credits. After a project uses an approved offset protocol to quantify its emissions reductions, it must continue to monitor, report, and verify its emissions reductions.

1. Role of the Offsets Program

The offsets program is designed to increase compliance flexibility and contain costs associated with complying with cap-and-trade program requirements. Because offset credits are expected to cost less than allowances, they are considered by many to be the most important cost-containment tool in the cap-and-trade program. Offset credits allow greater flexibility for covered entities to cover their emissions by offering an additional supply of compliance instruments in the market, which can create a demand for lower-cost emissions reductions and reduce the overall cost of achieving the emissions cap.

In addition to increasing the cost-effectiveness of the program, the California offsets program can benefit other AB 32 goals by:

- Stimulating emissions-reduction opportunities and technological innovation in sectors outside of the capped sectors.
- Encouraging early emissions-reduction activities while providing a transition period for industry to develop and deploy low-GHG technologies.
- Promoting technology and knowledge transfer between developed and developing countries, such as helping to preserve rainforests in danger of deforestation.
- Providing environmental, social, and economic benefits, such as reduced air or water pollution through improved land management practices and wildlife habitat.

Staff recognizes that a robust supply of offset credits can help to contain the costs of a cap-and-trade program. To promote the supply of offsets, staff proposes that: (a) ARB issues offset credits for projects using ARB-approved protocols, and (b) ARB recognizes offset credits from ARB-approved offset programs. Approved programs could include sectoral programs such as those Reducing Emissions from Deforestation and Forest Degradation (REDD) in developing countries. Offset credits from linked programs (such as WCI partner jurisdictions) would also be eligible for use in California's cap-and-trade program. ARB staff incorporates provisions in the proposed regulation to allow these two methods to be used following Board approval of specific protocols or programs.

Staff has developed four compliance offset protocols, , which can be found in Parts II through V of the Cap-and-Trade Program Staff Report, for use under the compliance offset program.. These protocols include the U.S. Forest Projects Protocol, the Livestock Manure (Digester) Projects Protocol, the Urban Forest Projects Protocol, and the U.S. Ozone Depleting Substances Projects Protocol. They are incorporated by reference in the proposed regulation and are being considered for adoption by the Board as part of this rulemaking package. While the program contains provisions to allow offset projects from North America, staff is taking offset protocols applicable in the United States to the Board for approval as part of this rulemaking package.

For these four protocols, staff relied on Climate Action Reserve (CAR) work on the four protocols for use in the voluntary offsets market. Staff recognizes the extensive contributions that stakeholders and experts have made to the CAR protocols, including fashioning effective solutions to difficult problems. Accordingly, ARB is relying on this work to help support ARB's offset quality objectives, as well as provide continuity and stability for offset projects both within California and other parts of the United States.

In addition to these four protocols, staff intends to review and adopt additional offset protocols in the future. Staff will evaluate additional offset project types and protocols. Protocols developed by third parties may be reviewed and, if applicable, be considered for adoption by ARB.

To ensure that there is a ready supply of offset projects developed according to Board-approved protocols, staff proposes to work with qualified third-party offset programs to bring offset credits from new offset projects into the offset program. Staff recognizes that third-party offset programs have existing capabilities and infrastructure that can be deployed quickly to enhance the supply of offset credits. The proposed regulation includes conditions and processes under which third-party programs can be approved to generate offset credits for compliance use according to ARB-approved protocols.

In addition to protocols developed and approved by ARB, staff proposes to recognize offset credits from existing offset projects under protocols developed for the four project types for purposes of early action. The proposed regulation includes a process for offset credits from qualified existing offset projects to be accepted into the compliance offsets program, to help create an initial supply of offset credits for the cap-and-trade program.

2. Transparency in the Offsets Program

Transparency is critical to the environmental integrity and effective administration of an offset program. The proposed regulation establishes an open and transparent offsets system to build confidence in the long-term success of the cap-and-trade program. ARB will ensure that information regarding offset projects and assessments will be made publicly available. The proposed regulation establishes requirements for offset projects and the offset credits they are issued to be listed on a publicly available webpage.

3. ARB as an Offset Program Administrator

An important procedural aspect of the offset program relates to the entity that issues offset credits. Staff proposes for ARB to play the role of a credit-issuing body, with provisions for third parties to fulfill some of these responsibilities subject to ARB oversight.

Offset credits are created for GHG reductions or removals that have been quantified, verified, and recorded. Credit-issuing bodies review all project quantification and verification information to determine if GHGs have been reduced. Once the credit-issuing body determines that the reduction occurred, usually based on third-party verification statements, they create (or issue) offset credits, each of which represents one metric ton of CO_2e.

As the offset program administrator, ARB would fulfill specific roles during the offset credit creation process. These roles include: approving compliance offset protocols as required by AB 32; reviewing and listing offset projects in the system; overseeing monitoring, reporting, and verification activities; and making

the determination of whether offset credits should be issued and, if so, how many. The regulation also proposes provisions to allow third parties that operate offset programs to fulfill some of these same roles, subject to ARB audits and oversight. These registries would be allowed to list offset projects in their own system and oversee monitoring, reporting, and verification activities. These third-party offset programs—referred to as *Offset Project Registries* in the proposed regulation—must meet requirements included in the proposed regulation and be approved by ARB. They must share all information they collect for offset projects with ARB, and make this information publicly available. Staff proposes to allow Offset Project Registries to assume these roles to access their existing capabilities and infrastructure so that the offsets program can be deployed quickly to enhance the supply of offset credits. The obligations and services of Offset Project Registries are discussed later in this Chapter.

4. General Requirements for Offset Credits Issued by ARB

The proposed regulation includes provisions to ensure all offset credits used for compliance purposes are real, additional, permanent, quantifiable, verifiable, and enforceable. Ensuring the environmental integrity of the offsets program is critical to guaranteeing the credibility of the entire cap-and-trade program, achieving the environmental objectives of real emissions reductions, and preserving the value of offset credits to project developers, offset buyers, and all market participants. To assure offset quality, the proposed regulation includes rigorous and transparent quantification methodologies, training and oversight of independent ARB-accredited verifiers, and a registration and tracking system.

The proposed program relies on offset protocols that are developed with stakeholder input, standardized, and approved by the Board. The offset quantification and the regulatory offset verification requirements are designed to reduce subjectivity and uncertainty. These procedures are the cornerstone of the offsets program and will help ensure the rigor and integrity of offset credits. The offsets verification program will require that verifiers demonstrate competence in each specific project type, employ conflict-of-interest assessments, and include random verifier audits and strict performance evaluations to ensure that verification activities are conducted accurately and consistently. The registry system for compliance instruments is being designed to provide strong enforcement capabilities, including mechanisms to prevent double-counting, public disclosure requirements, and methods to clearly define ownership.

5. Approving Compliance Offset Protocols

Offset credits issued by ARB must be generated using offset protocols adopted by the Board. The proposed regulation establishes a process by which the Board will approve and amend protocols and their quantification methodologies based on staff's evaluation and a public process. These protocols will be made publicly available so that anyone interested in developing an offset project can do so according to Board-approved standards.

Four protocols are part of this rulemaking package, as described below. ARB staff will periodically propose new offset protocols or revisions to previously approved protocols to reflect the current regulatory environment and latest scientific information, to the Board. Before ARB staff brings new protocols or updates to existing protocols to the Board, a public stakeholder process will be conducted to develop, review and revise the offset protocols. Before the Board adopts a new protocol there will be a separate CEQA review to assess the environmental impacts associated with that protocol.

Four Protocols for Board Approval

As part of this rulemaking package, staff is bringing four offset protocols to the Board for approval:

- **U.S. Ozone Depleting Substances (ODS) Projects Protocol:** Destruction of ODS from refrigerant and foam-blowing agents sourced from and destroyed within the United States. Production of ODS is being phased out through the Montreal Protocol, but there are significant banks from which these gases will be emitted in coming years unless they are destroyed. ODS destruction has stratospheric ozone benefits in addition to climate benefits.

- **Livestock Manure (Digesters) Projects Protocol:** Capture and destruction of methane from anaerobic manure treatment and/or storage facilities on dairy cattle and swine farms within the United States.

- **Urban Forest Projects Protocol:** Urban tree planting projects by municipalities, educational campuses, utilities, and partner organizations to sequester carbon.

- **U.S. Forest Projects Protocol:** Increasing sequestered carbon or avoided GHG emissions due to forest management activities in three project types: reforestation, improved forest management, and/or avoided conversion within the United States.

ARB has coordinated with the other WCI partner jurisdictions to develop the offset program, and three of these proposed protocols have been reviewed as part of that effort.[34] The U.S. Ozone Depleting Substances Projects Protocol has not been part of this review process to date, but the WCI Partner jurisdictions are

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[34] Det Norske Veritas. *Review of Existing Protocols Against WCI Offset Criteria.* For the Western Climate Initiative. April 2010. Found at: http://www.westernclimateinitiative.org/component/remository/Offsets-Committee-Documents/WCI-Review-of-Existing-Offset-Protocols.

currently reviewing it and assessing it relative to the WCI offset criteria recommendations. Staff will continue to work within WCI to address any issues that may arise with use of this protocol in the context of linking with a WCI Partner.

Staff is relying on the work that the Climate Action Reserve (CAR) has done to develop these four protocols for use in the voluntary offset market. In reviewing these protocols for possible use in the cap-and-trade program, staff examined all aspects of the protocols, including but not limited to the following:

- Mechanisms for ensuring permanence in forest projects, to ensure that they are effective and enforceable by ARB.
- Technical details, including incorporating minor adjustments to emission factors.
- Modifications to each protocol to align them with the requirements of the cap-and-trade program, such as aligning project start eligibility dates and crediting periods, or alignment of terms and definitions.

On June 23, 2010, staff held a workshop to discuss the transition of the four CAR protocols for use in a compliance program. Specifically, this workshop focused on options for aligning the most recent versions of these protocols with the offset criteria proposed in the cap-and-trade regulation. In addition to seeking public input, a CEQA review of each protocol has been completed and is included as part of this regulatory package in Appendix O: Functional Equivalent Document.

6. Requirements for Compliance Offset Protocols

Compliance offset protocols serve as a cornerstone to ensure that reductions are appropriately quantified, monitored, reported, and documented. Protocols taken to the Board for adoption will consist of standardized methods that quantify reductions based on specific criteria and pre-established calculation methods. This approach will streamline the calculation of project baselines and determination of additionality of projects by using standard eligibility criteria that ensure that projects are additional. Protocols approved by the Board will include project-type-specific monitoring and reporting requirements and methods for addressing leakage.

a. Additionality

Protocols approved by the Board provide a basis to determine whether offset projects are additional. Approved protocols are designed to ensure that the determination of additionality will be replicable for all offset projects of the same type. Additionality in the offset program requires that ARB only credit projects that would not have otherwise occurred in the absence of an offsets mechanism. Staff designed the offset system with this requirement to be consistent with AB 32, which requires that emissions reductions used for compliance must be "in addition to any greenhouse gas emissions reduction otherwise required by law or

regulation, and any greenhouse gas emissions reduction that otherwise would occur" (HSC §38562[d][2]). Most existing offset programs have excluded project activities required by law or regulation from receiving offset credits in their programs. However, staff expects some GHG emissions-reduction activities not required by law or regulation to occur under a business-as-usual scenario. ARB is defining *additionality* to exclude these offset projects from receiving credit.

The proposed regulation establishes that an offset project, which has already begun to generate offset credits under a protocol approved by the Board, may continue to generate offset credits until the end of its crediting period, even if in the future regulations are adopted that mandate reductions from projects that have already begun to generate offset credits. At the time a newly adopted regulation takes effect, a project type or technology would cease to be additional for new offset projects wishing to enter the system. Generally an offset project will be developed if the revenue it expects to generate over the length of the crediting period will cover its upfront investment and ongoing maintenance costs. This means that an offset project will be implemented only if it is expected to be financially beneficial to do so over that length of time. Therefore, staff believes that offset projects should be credited for emissions reductions throughout the entire crediting period. Crediting periods are discussed in more detail later in this Chapter.

b. Project Baselines

Project baselines are a core component of the quantification process and the determination of additionality. Project baselines are conservative estimates of business-as-usual reductions or removals for an offset project. The difference between the project baseline and the reductions achieved by the offset project is what will be considered beyond business-as-usual, and therefore creditable as an offset. Therefore, in the proposed regulation, staff proposes to require that protocols include a method for calculating project baselines to quantify a project's emissions reductions. The GHG reductions or removals can only be assessed if the baseline reflects an accurate and realistic business-as-usual emissions scenario.

c. Accounting for Leakage

In the context of offset credits, *leakage* refers to a shift in emissions due to the offset project activity to another place that negates some or all of the emissions reductions achieved by the offset project. Leakage can occur with offset credits because they are based on individual projects. The proposed regulation requires that protocols include a clear methodology to account for leakage when quantifying emissions reductions from offset projects. Two types of leakage must be accounted for in offset projects, if applicable for the specific offset project type: activity-shifting and market-shifting leakage. Any leakage associated with an offset project type will be factored into the final calculation of emissions and emissions reductions for individual offset projects.

d. Accounting for Uncertainty

When uncertainty exists in quantifying GHG reductions, ARB will only issue offset credits when there is a high level of confidence that reductions actually occurred. Staff proposes to employ a principle of conservativeness in the quantification of emissions reductions. This method will ensure that the accounting will underestimate rather than overestimate any reductions when there is a high level of uncertainty. Staff prefers this approach to applying an arbitrary discount factor to account for uncertainty after emissions reductions have been verified. Applying a single discount factor across projects to account for risk and uncertainty could penalize projects that achieve truly real and additional emissions reductions.

e. Permanence Requirements

Permanence refers to the period of time that an emissions reduction must stay absent from the atmosphere. In general, it is equal to the duration of an emitted GHG in the atmosphere. Requiring permanence in the offsets program ensures that if there is a risk of reversal, the atmosphere can be made whole. It also ensures that offset credits are equivalent to emissions reductions that would be achieved from covered entities at their facilities. Permanence is particularly an issue in projects with a risk of GHG reversal, such as sequestration-based projects. Disturbances, such as fire, insects, disease, and project mismanagement or failure can return sequestered carbon or release GHGs to the atmosphere.

In the case of sequestration-based projects, the proposed regulation requires an upfront commitment by the project developer to permanently maintain GHG reductions to ensure permanence. To achieve this, staff proposes to establish a Forest Buffer Account to provide insurance, in the case of an unintentional GHG reversal. The details of the Forest Buffer Account are discussed later in this Chapter. Although staff includes the Forest Buffer Account to deal with unintentional reversals, there are still risks that intentional reversals can occur in forest projects. In this, case the forest owner must replace all credited carbon that has been reversed.

f. Crediting Periods

Each protocol must establish a crediting period for the relevant offset project type. The crediting period refers to the period that an offset project is allowed to be issued compliance offset credits. Without certainty about a project's life span, there may be too much risk for a project to attract investors. Therefore, staff understands there must be some guarantee that the emissions reductions achieved according to a protocol will be eligible to generate offset credits for a given period. However, some types of offset projects could no longer be valid for generating offset credits in the future. This could be because the offset projects have become unadditional because business practices change or the sources are now suited for direct regulation or another market-based incentive program. Staff determined that there must be a balance between guaranteeing investment

certainty and allowing ARB to update methods and quantification, as well as to reevaluate and readjust baseline and additionality requirements in protocols in the future.

To achieve this balance, staff proposes to set a range for crediting periods. For non-sequestration projects, each protocol will include a crediting period between seven and 10 years. Staff believes that this is sufficient time needed to make an investment attractive for most non-sequestration projects. For sequestration-based projects, each protocol will include a crediting period between 10 and 30 years. Staff recommends this period for sequestration projects because they require long-term investment and commitment by project developers, and these projects achieve gradual GHG removals over longer timescales. Staff will establish a crediting period for a specific project type in each protocol.

The proposed regulation includes two types of crediting periods: an initial crediting period and a renewed crediting period. The initial crediting period occurs once and begins on the date that the first verified GHG reductions occur according to an offset verification statement submitted by an ARB-accredited verifier. Offset projects may qualify for renewed crediting periods if they continue to meet the requirements for additionality. An offset project must also utilize the most updated version of an approved protocol for that offset project type at the time of renewal. An offset project that does not involve sequestration of GHGs may be renewed twice. Staff believes this is generally the amount of time that an offset project in industrial sectors will remain additional. There is no limitation on the number of times a crediting period may be renewed for sequestration-based offset projects; however, when added together the crediting periods may not exceed a total of 100 years.

7. Requirements for Offset Projects

The proposed regulation establishes requirements for offset projects if they want to be issued offset credits. These include using a Board-approved protocol, meeting the requirements for additionality, being located in an applicable jurisdiction, and complying with all applicable laws and regulations at the national, state or provincial, and local levels. Throughout this Staff Report, those that develop offset projects are referred to as offset project developers, without elaborating on who these parties may be. Under the proposed regulation, those that have legal authority to implement offset projects—referred to as *Offset Project Operators* in the proposed regulation—must identify themselves to ARB or an Offset Project Registry. In most cases these are facility operators or landowners. Many times facility operators or landowners will contract with third- party investors to assist in the development, implementation, and maintenance of the project. Staff recognizes that some facility operators and landowners may not be the parties implementing and overseeing the offset project; therefore, staff is allowing these parties to identify another party—referred to as an *Authorized Project Designee* in the proposed regulation—to be identified as responsible for the offset project. In the proposed regulation, a facility operator or landowner may delegate responsibilities, such as

communications with ARB or an Offset Project Registry regarding the offset project, to an Authorized Project Designee. In some cases, the facility operator or landowner may also assign rights to own offset credits that are issued to the offset project to the Authorized Project Designee or another third party.

a. Requirement to Use a Compliance Offset Protocol

An offset project developer must use a protocol approved by the Board to qualify for the issuance of offset credits. Staff will make all approved protocols available on ARB's public website.

b. Requirements for Additionality

Offset project developers must ensure that offset credits generated under their project are considered additional. To be additional GHG reductions must result from activities that:

1. Are not required by or undertaken to comply with any federal, state or local law or ordinance, including any regulation, consent order, and stipulated agreement or Memorandum of Understanding.

2. Are not considered common practice or would not have occurred under a business-as-usual scenario.

3. Were not commenced prior to January 1, 2007.

4. Exceed a project baseline calculated by a protocol for an offset project of that type.

Establishing the eligibility date for an offset project is critical to determining the additionality of offset projects. The eligibility date is the date from which a project can be issued offset credits by ARB. ARB will not issue offset credits for emissions reductions until after they have been verified. For the issuance of offset credits, ARB is proposing that offset projects which commence on or after January 1, 2007, be eligible. This date is the implementation date of AB 32 and provides for a better likelihood that the project was implemented to achieve AB 32 goals. Staff is also proposing that when recognizing offset credits issued according to non-ARB offset protocols or those issued by other programs approved by ARB, the eligibility date may differ from the date for ARB-issued offset credits. For purposes of recognizing projects undertaken to achieve early action GHG reductions, staff may recognize offset credits issued prior to January 1, 2007. The specific eligibility date requirements will be established depending on the evaluation of a specific program or set of protocols.

c. Locations of Offset Projects

While staff proposes to allow offset projects from North America to be credited under ARB-approved protocols, staff is only taking protocols to the Board for approval as part of this rulemaking package that are applicable for projects in the United States and its territories. Staff plans to evaluate how the four protocols

being taken to the Board can be expanded to include projects in Mexico[35] and Canada. Although staff encourages offset projects to be developed in California, it recognizes out-of-state projects will expand the scope of the program to allow for more low-cost GHG reduction possibilities to be incorporated and reduce the overall costs of the program. Therefore, staff recommends that ARB issue offset credits for projects located in the U.S., Canada, and Mexico. Staff proposes that all GHG reductions for offset projects, whether they are located within or outside of California, be verified by an ARB accredited third-party verifier, and that ARB have the ability to audit all accredited verifiers.

Offset credits from projects located outside of North America may also be used for compliance if they are issued by an outside program that is approved by the Board, though no such approval of another program is being recommended at this time. Recognition of offsets issued by other programs is discussed in more detail in Section B of this Chapter.

Staff's intent in approving protocols is that the standard for additionality will be set to reflect the most stringent regulatory or legal requirements among linked WCI partners. This would result in the most conservative assessment of GHG reductions, helping to ensure the integrity of the offset system. Setting an additionality standard based on the most stringent regulation in the region would remove any incentive to weaken or solely maintain environmental protections to qualify more offset projects. For some project types it will be difficult to apply this standard in the protocols based on regional differences. For these project types, staff may address regional differences using alternative methods.

d. Environmental Assessment Requirements

In the proposed regulation, staff includes requirements that offset projects meet all local, state, and federal laws for environmental assessments. The purpose of including this requirement is to ensure that offset project developers assess and disclose any potential impacts associated with implementing their offset projects. While staff is not requiring that offset projects meet specific requirements for environmental assessments, this requirement acknowledges the importance of all potential projects adhering to the environmental laws of the jurisdiction in which the project is located. For example, new offset projects in California may be subject to local permitting processes and, if not exempt, environmental review under CEQA.

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[35] Staff does not intend to evaluate an ODS protocol for offset projects in Mexico because the substances covered under the protocol have not yet been completely phased out in developing countries.

8. Listing Offset Projects

The proposed regulation requires that project developers "list" their projects—or submit information pertaining to their offset projects—with ARB or an Offset Project Registry. Listing establishes a mechanism for a project developer to record information on their offset project for ultimate issuance of offset credits. Project listing requires the submittal of information on each project for transparency purposes. The requirements for what information must be submitted can be found for each type of offset project in its corresponding protocol, all of which are incorporated by reference in the proposed regulation. Before listing, a project developer must register for an account with ARB to hold compliance instruments and must attest to ARB that all information they submit for listing purposes is truthful and accurate. These attestations will be used for enforcement purposes.

All listed projects and associated information will be posted on a publicly available website. Once ARB or an Offset Project Registry has determined that all the information submitted by the project developer is complete and that the offset project generally meets the requirements for additionality, it will be listed as a "proposed" project on the website. This status will change to an "active" project once the project developer submits its verification statements (attested to by an ARB-accredited verification body) and ARB or an Offset Project Registry issues an offset credits for the GHG reductions. Changing the status of the offset project from "proposed" to "active" will allow the public to know that the offset project has begun to be issued offset credits and has completed its first verification process.

The listing process is not intended to be an approval process for offset projects. The determination that an offset project meets all the regulatory requirements occurs at the time an accredited verifier issues a positive or qualified positive offset verification statement and ARB or the Offset Project Registry issues an offset credit based on that statement. This means that some offset projects may be listed as a proposed project but never have the status changed to an active project or receive offset credits.

Offset project developers are required to list their offset projects for an initial crediting period no later than the date they submit their project's first annual reporting data. For renewed crediting periods, project developers must submit their listing information no earlier than 18 months before and no later than 9 months after the conclusion of the previous crediting period. This timeframe establishes the period of time in which additionality would be assessed and will also determine which protocol version should be utilized.

9. Monitoring, Reporting, and Record Retention Requirements for Offset Projects

Ongoing monitoring of offset projects is necessary to ensure that offsets credited to the project have occurred, and to provide the necessary data for quantifying and verifying GHG reductions. Monitoring requirements in the proposed

regulation include measurement and data collection for key project parameters, as well as related procedures and quality control procedures. The monitoring requirements address what needs to be measured, how often it needs to be measured, and what methods and instrumentation are acceptable for data collection. General monitoring requirements can be found in the proposed regulation, while specific requirements for each type of offset project can be found in the individual protocols. Protocol-specific monitoring requirements increase consistency among projects of the same type, while allowing monitoring requirements to be tailored to each project type.

Staff includes separate requirements for the substitution of missing fuel analytical data in the proposed regulation, in the case that an offset project's gas or fuel analytical monitoring data equipment breaks down. In turn, it is necessary to collect data that would be needed to support the missing data substitution procedures for fuel use. The offset project developer may benefit from such a provision because it could reduce or eliminate the need for more punitive data substitution in a missing data situation.

The proposed regulation requires reporting on the performance of offset projects, including summarizing project monitoring data, calculating the GHG reductions achieved in the applicable period, and documenting that information in a project report. The required content and level of detail demanded in project reports—referred to as *Offset Project Data Reports* in the proposed regulation—vary between project types.

Staff proposes an annual reporting frequency. Reductions can be aggregated by year and reported once every six years in the case of urban forest projects. Staff chose these timeframes because reporting represents a project cost due to the resources required to prepare and subsequently verify reported data. Staff believes these timeframes strike a balance between cost and accountability, and are cost-effective for the various types of offset projects. All reports will be due on April 1 of the subsequent year for which GHG reductions are being reported. These general requirements for offset project reporting are described in the proposed regulation. There are also specific reporting requirements for each type of offset project in the individual protocols. In addition to meeting these requirements, project developers must submit a statement to ARB attesting to the accuracy and truthfulness of the Offset Project Data Reports they submit. If a project developer fails to submit their reported data by the appropriate deadline, they will be disqualified from being issued offset credits based on the reported GHG reductions covered in that particular data report.

The proposed regulation includes requirements for project developers to retain records and documents pertaining to monitoring and reporting activities. Project developers must retain all information used to develop their Offset Project Data Reports. The information retained must also be sufficient to allow for verification of the GHG reductions contained in each report. These general record retention requirements can be found in the proposed regulation, while specific

requirements for each type of offset project are described in the individual protocols, if applicable. Developers of non-sequestration-based projects are required to retain these records for five years after the crediting period in which that data report is submitted ends. Developers of sequestration offset projects must retain these records for the length of time that the offset project is issued offset credits plus 100 years.

10. Verification for Offset Projects

Verification is the process of reviewing offset project information to ensure that claimed GHG emissions reductions have been achieved in accordance with the proposed regulation. According to the proposed regulation, verification will occur after project implementation and prior to offset credit issuance.

In the proposed regulation, staff includes requirements for a verification program that are consistent with international standards and subject to ARB oversight. This oversight includes verifier accreditation, verification body accreditation, requirements for verification services, and conflict of interest requirements. The proposed regulation includes enforcement provisions that apply to parties that participate in the offset program. These parties include offset project developers, verifiers, and covered entities.

To establish a high level of trust in the program and address public concerns related to the integrity of offset projects, staff has developed a verifier accreditation process and conflict-of-interest process that ensures quality in the evaluations and prevents potential bias when offset projects are verified by independent third parties.

The verifier and verification body accreditation program established in the MRR for purposes of emissions reporting will be expanded to include the accreditation of verifiers and verification bodies for offsets. Expanding the accreditation program will involve project type or protocol-specific training for verifiers accredited through the MRR program.

a. Offset Verification Services

Staff includes several key elements for offsets verification in the proposed regulation. The first is a mandatory site visit during the first year of verification. Site inspection allows the verification team to ensure that all GHG sources, sinks, and reservoirs within the defined offset project boundary are included in the project's reduction and removal estimates and that the reported data are complete as required by the proposed regulation and the applicable protocol. It is also an opportunity for the verifier to assess the adequacy of the data management and data acquisitions systems used to collect and process data underlying reduction and removal estimates. At the same time, the verification team may conduct a review of contracts and other documents to substantiate reported data and ensure that data sampling and monitoring were conducted as applicable in the regulation and applicable protocol.

The offset verification team is also required to develop a verification plan. Verification plans provide documentation of planned activities, site visits, and document reviews. The plan will be submitted by the verification body to ARB or an Offset Project Registry, if applicable, with a Notice of Verification Services, ten days prior to a kick-off meeting with the offset project developer. The Notice of Verification Services allows for ARB to plan in advance for any additional oversight of the verification, with dates of verification activities proposed in advance.

A critical element of offset verification is the sampling plan. This plan is used to conduct data checks on the reported GHG sources, sinks, and reservoirs. Offset verification does not call for a duplication of all calculations, but rather checking specific subsets of the reported data based on several criteria. Selection of data subsets for checking involves a review of the largest contributions to overall GHG sources, sinks, and reservoirs that result in reduction or removals, as well as the sources, sinks, and reservoirs associated with the greatest uncertainties in estimation. Therefore, the sampling plan includes a ranking of source contributions to overall GHG sources, sinks, and reservoirs and a ranking of sources, sinks, and reservoirs with the greatest calculation uncertainty.

The offset verification team conducts a qualitative risk assessment based on the uncertainty of the data acquisition equipment, data sampling and frequency, data processing, reduction or removal calculations, data reporting, and management policies or practices applied to the Offset Project Data Reports. For example, in evaluating the uncertainty of the data acquisition equipment, an offset verifier may check the age of a meter or the maintenance record for the meter. For data processing, the offset verifier may check how the data management system records and tracks data that supports reduction or removal estimates. The risk assessment qualitatively evaluates how much confidence rests with the underlying infrastructure that generates reduction or removal estimates.

The proposed regulation does not prescribe the number of data checks that the offset verification team must perform. The offset verification team must exercise professional judgment in choosing these. Ultimately, the offset verification team must have reasonable assurance that the reported emissions reductions or removals do not contain a material misstatement that would overestimate reductions or removals or a material misstatement that would underestimate by more than 5 percent the reported emissions reductions or removals, and that all applicable regulatory requirements in the proposed regulation and the applicable protocol have been met in the estimation and reporting of those reduction or removal estimates.

During the course of the offset verification, the offset verification team is required to maintain an issues log of any findings that may affect materiality or conformance with the proposed regulation. The offset verification team must also log how those issues are resolved to the satisfaction of the team so that the verification body may then provide a positive offset or qualified offset verification

statement. Any findings that result in a change of the initial Offset Project Data Report submitted to ARB or an Offset Project Registry must be documented. This careful documentation provides transparency in the offset verification process and allows ARB to follow the verification in detail as part of its oversight role.

b. Completing the Offset Verification Process

Upon completion of review by the offset verification team, the verification body may submit a positive offset verification statement to the operator—and ARB and/or an Offset Project Registry—if the offset verification team has found no material error in the Offset Project Data Report, and if the team finds the report meets the requirements of the regulation. The verification body may submit a qualified positive offset verification statement if the team has found no material error in the report, but it may include one or more nonconformance(s) with quantification, monitoring, or metering requirements that do not result in material error. The verification body may also submit an adverse verification statement if the team has found material error or is otherwise unable to state that the Offset Project Data Report meets the requirements of the regulation. When providing the offset verification statement, the verification body will have an opportunity to add any comments or qualifiers they deem necessary to provide a complete context for the verification. The verification body will also submit a detailed verification report to the offset project developer that includes the verification plan, sampling plan, issues log, and additional documentation. The detailed verification report is retained by the project developer, but is made available to ARB or an Offset Project Registry upon request. The detailed verification report may be used by ARB or an Offset Project Registry at its discretion, to review the work of the verification body or review the verification process or the submitted data.

If a verification body and offset project developer cannot agree on the verifiability of the reported reductions or removals, or the need to revise the Offset Project Data Report, the project developer may petition ARB or an Offset Project Registry for review of the offset verification statement. ARB could use any experts at its disposal to review questions, and both parties would be held to the subsequent ARB decision.

11. Verifier and Verification Body Accreditation

A key element for ensuring the credibility of the offsets program is independent verification of reductions or removals to ensure the completeness and accuracy of the estimates and conformance to the regulation. Under the proposed regulation, verification for offsets will be performed by qualified and trained third-party verifiers that meet specifications for education and experience, and demonstrate that there is no conflict of interest for verifying reductions or removals due to current or previous relationships with the project developer. Verifiers will be required to attend a multi-day ARB-approved verifier training

course and successfully complete an exit exam prior to being accredited to provide verification services for offset projects.

For offset verification, staff recognizes the need for project type- or protocol-specific verifiers, especially in the case of forestry projects or those including carbon sequestration. These sectors often have complex baseline and emissions-reduction calculation methods, contractual arrangements, and sales and purchase complexities that require verifiers to have special knowledge. ARB will offer project type-specific training in addition to general verification and lead verifier training. All lead verifiers and general verifiers may take the additional project type-specific training if there is a training offered by ARB. Lead verifiers who lack experience in environmental or financial auditing would have additional training. Based on guidance from existing programs, such as the International Organization for Standardization (ISO), these various requirements aim to ensure quality and consistency in the conduct of verification activities.

12. Conflict of Interest for Offset Projects

Conflict of interests arise when an individual or organization have interests in one activity that could possibly influence its objectives in another activity. Conflict-of-interest safeguards are especially important in the offsets program because verification bodies and the offset project developers enter into contracts for performing verification activities, in which they agree on a monetary payment for services rendered. In an offset verification scenario, the verifier reviews the amount of GHG emissions reductions reported, as well as the project developer's conformance with the requirements of the regulation. The monetary value of this contractual relationship depends on the complexity of the project verified by the verification body. The proposed regulation contains requirements and criteria for potential conflict-of-interest assessments between verification bodies and offset project developers to prevent them from occurring.

The conflict-of-interest requirements in the proposed regulation ensure that the verification process is independent and free of any external bias or interests of the verifier influencing the review of data reported by the offset project developer. The proposed regulation provides guidance and criteria as to what types of relationships and practices are unacceptable between a verification body and the offset project developer.

Prior to providing verification services to an offset project developer, the verification body must evaluate the level of potential conflict between itself and the developer. The proposed regulation provides requirements and criteria for determining whether a potential conflict is low, medium, or high. If the potential conflict is determined to be high, then offset verification may not commence between that verification body and the project developer. If the potential conflict is found to be low, then the verification may commence. If there is a medium level of risk for conflict of interest, and the verification body wishes to pursue offset verification services, it must provide a plan for how it will mitigate any

conflict before finding the risk as acceptable and proceeding with the offset verification process.

ARB plans to train its accredited offset verifiers to properly assess conflict-of-interest situations based on the criteria laid out in the regulation. ARB's role in the conflict-of-interest process will be actively auditing the offset verifiers to ensure they appropriately assess and certify their conflict of interests before they move forward with providing offset verification services.

The proposed regulation contains a requirement for offset project developers to change offset verifiers after six years to avoid potential conflict-of-interest issues from lengthy business relationships. This results in a new set of eyes to review the reduction or removal estimates provided by the project developer. Staff includes this requirement to reduce complacency that may occur given the familiarity a verification body may feel toward an offset project developer after that time period.

13. Issuance and Registration of Offset Credits

Once emissions reductions or removals from projects listed through the ARB process have been verified and issued a positive offset or qualified positive offset verification statement, ARB or an Offset Project Registry will issue offset credits in an amount equal to the GHG reductions or removals verified. Each offset credit that is issued by ARB or an Offset Project Registry will be assigned a unique serial number and be entered (registered) into the respective registry systems and subsequently the account of the registered owner of the offset credits, unless the offset credit is being diverted into ARB's Forest Buffer Account for forestry permanence purposes. Owners of offset credits will be notified by ARB or an Offset Project Registry within 45 days of the determination for issuance of offsets.

Offset credits do not constitute a property right and may be invalidated by ARB. Once issued, offset credits can be traded, sold, or used as part of an entity's compliance obligation. To ensure that offset credits are not double-counted, the serial numbers must be taken out of circulation when an offset credit has been retired or used for compliance.

Before offset credits issued by Offset Project Registries can be used for compliance in the cap-and-trade program, all information for that offset project submitted by the project developer to the Offset Project Registry—including listing, reporting, and verification information—must be transferred from the registry to ARB. The offset project developer must also submit a series of attestations to ARB stating that all information they have submitted to a registry is truthful and accurate. These attestations provide an enforcement link between the project developer and ARB. In the event that ARB needs additional information regarding the initial information submitted, ARB will notify the project developer and allow time for this review. After all information is satisfactory and the attestations are made, ARB will issue an offset credit within 30 days. ARB

will place it into the owner's Holding Account once it has confirmation that any corresponding offset credit has been retired in the originating registry.

14. Forest Buffer Account

The proposed regulation establishes a *Forest Buffer Account*—a permanence mechanism for ensuring GHG emissions remain out of the atmosphere—to replace offset credits in the event of an unintentional reversal. The account acts as an insurance policy; the developers pay a premium up front to be fully covered in the event of an unintentional loss of sequestered carbon. An unintentional reversal of stored GHGs means any reversal, including wildfires or disease, that is not the result of the forest project developer's negligence, gross negligence, or willful intent. Ultimately, the risk of impermanence may affect the cap, if obligated metric tons are lost, and the liable party is not able to make good on their obligation. In the case of an unintentional or an intentional reversal, the forest project operator must notify ARB of the reversal and how many metric tons were reversed. If the unintentional reversal reduces the project's stored carbon below its project baseline, the project will automatically be terminated, but the developer may relist the offset project under certain conditions. If the reversal is intentional, the offset project will be terminated, and it may not be relisted.

The proposed regulation requires that a portion of all offset credits issued by ARB to offset projects developed according to ARB's U.S. Forest Projects Protocol be placed into the Forest Buffer Account to cover unintentional reversals. The forest project operator is required to follow the methods in the U.S. Forest Projects Protocol for calculating the project's risk rating. The risk rating is based on a number of default and calculated factors that differ depending on the individual project. The factors and equations that must be used to determine each project's risk rating are provided in the protocol.

The project must place offsets into a buffer mechanism, regardless of whether a forest project originates with ARB or an Offset Project Registry. If a forest project originates through the use of an Offset Project Registry, all offset credits that are set into the Offset Project Registry's buffer account must be transferred to ARB at the time that a forest offset credit is brought into the compliance offset program.

Staff will monitor the use of the Forest Buffer Account over time. If the account appears to be diminishing at a faster rate than it is being replenished, ARB may need to adjust the U.S. Forest Projects Protocol to require that more offset credits are placed into the buffer pool in the future. If the buffer pool is ever exhausted, staff would evaluate options for replenishing it, including potentially retiring allowances from the Reserve.

15. Invalidation of Offset Credits

To ensure the enforceability of compliance offsets, ARB needs to have the ability to investigate and take action for violations or noncompliance with the proposed regulation. There are two primary reasons that ARB may need to invalidate offset credits after they have been issued: (1) fraud or malfeasance on behalf of

the project developer, the third-party verifier, verification bodies, or others involved in producing the documentation used to support the issuance of offset credits, or (2) a reversal in the forest sector. If an offset credit has been used for compliance or retired and is subsequently invalidated, it must be replaced within 30 days. If the offset credit has already been retired, staff is proposing in all cases of fraud or malfeasance that the entity that used or retired it be responsible for replacing the invalidated offset credits. The covered entity may then take appropriate action through third-party contractual arrangements they may have established prior to purchase. These arrangements currently exist in the voluntary offset market, and staff expects that as the offset market becomes more established, that a standardized contract for third-party liability will be established. In the event that the offset credit has not yet been used or retired, it will be canceled in the market tracking system and removed from any Holding or Compliance Accounts.

If there is an unintentional reversal in the forest sector, staff will retire the appropriate number of offset credits from the Forest Buffer Account, whether or not they have already been used or retired within the system. If there is an intentional reversal in the forest sector, staff proposes that the forest project developer replace the invalidated offset credits within 30 days, whether or not they have been retired within the system. Staff is proposing to hold the project developer liable for intentional reversals in the forest sector because the risk of reversal is more prevalent. Buyers will have little incentive to invest in forestry projects if the liability falls back to them. Instead they will pursue projects with more certain emissions reductions.

16. Offset Project Registries

Staff includes provisions in the proposed regulation to allow third-party offset programs (Offset Project Registries), that meet ARB standards, to perform many of the responsibilities in the offset creation process to take advantage of their resources and expertise and minimize the administrative burden of the offsets program on ARB staff. The responsibilities that Offset Project Registries may take on include: listing offset projects; overseeing monitoring; reporting; and verification activities; and issuance of ensuing offset credits. These services are also referred to as *registry services.* All offset credits issued according to Board-approved protocols must be verified using ARB-accredited verifiers. ARB would still need to perform required CEQA analyses, adopt compliance protocols, and oversee Offset Project Registry activities. ARB oversight of the conduct of Offset Project Registries and ARB-accredited verifiers is critical to the overall quality of the program.

The proposed regulation includes comprehensive requirements that an Offset Project Registry must meet to be approved by ARB, including the submittal of: an application, information regarding its staff and Board members, and proof of professional liability insurance. ARB will then evaluate the application and information submitted to ensure that it meets the regulatory criteria in the proposed regulation and does not have any conflict of interests. If the program is

approved, ARB will issue an Executive Order designating the Offset Project Registry to provide registry services which will be valid for five years. At the end of the five years it may reapply to continue offering registry services to ARB. ARB may also decide to modify, suspend, or revoke this approval for good cause.

Offset Project Registries are required to make specific information publicly available on all of the listed offset projects. They are also required to perform annual audits of 20 percent of a representative sample of listed offset projects. This information must be submitted to ARB, along with an annual report of its findings. The Offset Project Registry must also make its staff and all documentation related to any offset project it lists available to ARB for audits, and it must retain all records related to its audits and its listed offset projects for a specified period of time, as laid out in the proposed regulation.

B. Recognition of Compliance Instruments from Other Programs

1. Early Action Offset Credits

Beginning in 2005, the Climate Action Reserve (CAR) and its predecessor, the California Climate Action Registry began adopting voluntary GHG accounting protocols to encourage voluntary early action to reduce GHG emissions. ARB recognizes the rigor of the voluntary accounting procedures CAR adopted to establish that GHG emissions reductions are real, additional, and permanent. CAR has issued approximately 7.5 million credits for offset reduction projects to date under its voluntary program.[36] Staff proposes to allow eligible offset credits and ongoing projects using protocols developed for four project types and adopted by CAR's Board to transition into ARB's compliance offset program. Recognition of early action offset credits will increase the supply of eligible compliance offset credits available in the short term.

Staff is proposing to allow offset credits issued according to the following protocols developed for four project types to be used for compliance purposes:

- Climate Action Reserve Livestock Protocol versions 1.0 through 3.0.
- Climate Action Reserve Urban Forestry Protocol versions 1.0 through 1.1.
- Climate Action Reserve Ozone Depleting Substances Protocol version 1.0.
- Climate Action Reserve Forestry Protocol version 2.1, or Climate Action Reserve Forestry Protocol versions 3.0 through 3.2, if the offset project has a conservation easement of has contributed offset credits based on its reversal risk to an insurance buffer account.

[36] Information found at: http://www.climateactionreserve.org/. (accessed October 24, 2010)

If an offset project has used one of the above-mentioned protocols, its offset credits may be used for compliance purposes if the GHG reductions meet the following criteria:

- Occurred between January 1, 2005, and December 31, 2014.
- Result from an offset project with an offset project commencement date prior to January 1, 2012.
- Result from an offset project located in the United States.
- Have not been retired, canceled, or used to meet a voluntary commitment or a surrender obligation in any voluntary or regulatory system.
- Meet the requirements for verification and conflict of interest for offset projects as required by the proposed regulation and required under AB 32 for all GHG reductions and GHG removals used for compliance purposes.

If an offset credit meets all of these requirements it may be used for compliance purposes. To avoid double-counting, the third-party offset program that issued the offset must retire it in their system before it is issued within ARB's tracking system.

Staff is aware that several voluntary offset programs currently use and may, in the future, use these protocols to issue offset credits. In the proposed regulation, staff includes requirements that an offset program must meet in order to have its offset credits issued according to these protocols for compliance purposes. If the program is an Offset Project Registry has been issued an Executive Order, it will be approved for purposes of recognizing early action offsets. If it has not been issued an Executive Order, it must prove it meets the requirements spelled out in the proposed regulation.

2. Sector-Based Offset Crediting Programs

Because climate stabilization requires global cooperation to reduce GHG emissions, staff proposes a framework for including sector-based offset credits from subnational programs in developing countries in the proposed regulation. Sector-based crediting is a concept that has emerged in international climate forums as an opportunity to broaden the scope and scale of emissions reductions in developing countries. It offers a bottom-up approach to developing-country mitigation, whereby host jurisdictions commit to establishing programs to reduce emissions in a particular sector of their economy, while jurisdictions in developed nations provide markets and other incentives to help finance those reductions.

The term *sector* refers to an economic activity or a group of related economic activities that occurs across a government jurisdiction. The cement and forest sectors are two examples. In a sector-based crediting program, a host jurisdiction's entire sector would need to meet an emission target before crediting

could be used in a California compliance market. The program's host jurisdiction would establish its own baseline (which would represent existing conditions for the particular sector) and a crediting baseline (which would represent a significant reduction in GHG emissions from its existing condition for the entire sector within that jurisdiction). Emissions reductions that occur below the crediting baseline could be issued credits that can be used by covered entities in the California compliance market, subject to approval of that program by the Board.

Sectoral approaches allow jurisdictions to focus on those economic sectors that have contributed the most significant GHG emissions within their jurisdiction or that have the potential for significant future emissions. By moving from a project-by-project approach, a sector-based crediting program can cover a larger geographical area or market and reduce the risk of emissions leakage within the jurisdiction. By crediting a sector based on some target level of reductions, competitiveness concerns among trade-exposed sectors can also be alleviated.

The regulation establishes a framework for accepting sector-based offset credits from developing countries. While staff is not proposing to approve any sector-crediting programs or adopt any protocols for sector-based offset credits at this time, this framework should help provide a necessary incentive for developing countries[37] to reduce their emissions and work toward meeting compliance grade sector-based offset credit requirements in California.

California has been working with state and provincial partners in two major initiatives exploring and developing sector-based offset crediting mechanisms. First, Governor Schwarzenegger established the Governors' Climate and Forests Task Force (GCF) in 2008. The GCF is a consortium of states and provinces aimed at establishing a market for forest carbon offset credits from reducing emissions from deforestation and forest degradation (REDD). Second, California has also been a leader and co-founder of the International Carbon Action Partnership (ICAP), a consortium of states and countries pursuing the development of carbon markets.

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[37] *Developing countries,* for the purpose of this regulation, are defined as those identified as Non-Annex 1 Parties by the United Nations Convention on Climate Change (UNFCCC). These countries have been recognized as being especially vulnerable to the adverse impacts of climate change and include countries with low-lying coastal areas, those prone to desertification and drought, and those that rely heavily on fossil fuel production due to their economic vulnerability to climate change mitigation measures. *Least Developed Countries,* as identified by the United Nations, are included in this list due to their limited capacity to respond to climate change and adapt to its adverse effects. California will also take into consideration opportunities where emissions reductions also have significant health benefits.

a. Sector-Based Crediting Program Approval

Each sector-based crediting program will need to be approved by the Board, and ARB's review of each sector-based crediting program will include a public consultation process pursuant to the Administrative Procedure Act. Staff anticipates a limited number of sector-based programs will be approved in the near-term because of the intensive review each program will undergo. Initially, staff anticipates that the Board would limit itself to working with subnational jurisdictions that have the most advanced and promising infrastructure necessary to develop sector-based programs. Staff also proposes that the first sectors to be considered for approval be developed through existing partnerships such as the GCF and ICAP. To that end, REDD is likely to be the first type of sector-based crediting program brought to the Board for consideration, as is discussed below in more detail.

Some general principles that will guide ARB's review of sector-based crediting programs include the following:

- Whether the sector represents a significant portion of the host jurisdiction's economy-wide GHG emissions.
- Whether the opportunities for reductions resulting from the program are especially significant.
- Whether the host jurisdiction has employed robust emissions monitoring, reporting, and verification practices.
- Whether the host jurisdiction has a GHG emissions-reduction strategy that incorporates reductions from its own domestic actions or policies in addition to reductions that result from a carbon offset program.
- Whether the program has homogeneity of the product, production process, and concentration of firms located or operating within the jurisdiction.
- Whether the host-jurisdiction's program includes means for public participation and consultation in the program design process.

Following Board approval of a program, offset credits generated from the program can be used for compliance in the California cap-and-trade program, consistent with the regulation. ARB will evaluate opportunities for additional programs after the first programs are established and tested.

b. Crediting Pathways to Emissions Reductions

Staff proposes the inclusion of two crediting pathways for ARB-approved sector-based crediting programs. A *crediting pathway* refers to how a sector-based crediting program issues credits for reducing or avoiding emissions, or for removing and sequestering carbon from the atmosphere.

The first type of crediting pathway would be used when an ARB-approved program achieves sector-wide emissions reductions from mitigation policies undertaken by or in coordination with the jurisdiction. The second crediting pathway occurs when an ARB-approved program issues credits to project developers for project-level activities that are "nested" within a jurisdiction-wide sectoral program. A nested system must coordinate the accounting of reductions at the project within the jurisdiction's own sectoral planning and accounting.

Under either crediting pathway, sector-based credits used for compliance in the California program must be additional to the host jurisdiction's legal requirements and in excess of the host jurisdiction's own commitment toward GHG emissions reductions for that sector. This additionality requirement ensures that the host jurisdiction is responsible for achieving a reasonable level of emissions reductions across the sector prior to credits being issued to covered entities.

c. Quantitative Limit

Because sector-based offset crediting programs are new and evolving, staff proposes to limit the number of sector-based offset credits allowed in the California compliance market to 25 percent of the overall quantitative offset limit during the first and second compliance periods, and 50 percent of the limit during the third compliance period.

d. General Sector-Based Offset Credit Program Elements

For the Board to consider a given sector-based crediting program for approval, the program would need to satisfy several criteria. While the proposed regulation establishes general requirements, staff will need to develop more sector-specific criteria and methodologies dependent upon the specific program considered prior to Board approval.

Programs must establish a business-as-usual reference-level baseline that accurately reflects the sector's historic and/or potential future GHG emissions for that jurisdiction's entire sector. The program would need an agreed level of deviation from the reference-level baseline, or *crediting baseline,* which is achieved through the jurisdiction's direct policies and mitigation actions. Sector-based credits could then be used for compliance once GHG emissions are reduced beyond the program's established crediting baseline. Emissions reductions must be verified by a third party to ensure reductions are real, additional, quantifiable, and permanent.

The program must also include a robust and transparent system for inventory, monitoring, and reporting to track and evaluate GHG reduction activities for the sector's emissions performance over time. Inventory and monitoring for land-use sectors should reflect, at a minimum, Intergovernmental Panel on Climate

Change (IPCC) Tier 2 methodologies,[38] which apply country or region-specific emission factors and higher temporal and spatial resolution rather than more general default factors and course resolution. The program will also need to establish an accounting mechanism that has the ability to reconcile accounting at both the project and sector level, as well as nest into a national accounting system, if one exists. A program must also include a registry, mechanisms for credit retirement, and protection against reversals where applicable. Each sector may require its own set of unique set of criteria beyond the general criteria currently included in the regulation.

e. Reducing Emissions from Deforestation and Forest Degradation (REDD)

Staff proposes that the first sector-based credits to be incorporated in the cap-and-trade program come from Board-approved REDD sector-based crediting programs. This recommendation is based on the important role that forests play in climate change in terms of sequestering carbon, and in particular, the role that tropical forests play in directly affecting the climate. According to the Technical Summary from the IPCC Working Group,[39] CO_2 emissions from tropical deforestation and degradation account for approximately 17 percent of global greenhouse gas emissions to the atmosphere, representing the second largest emissions sector after fossil fuel use.

The significance of deforestation emissions has brought the issue to the forefront of both domestic and international negotiations. Attention has focused on developing a REDD mechanism that offers incentives for domestic actions to further avoid deforestation and to transition to a low-carbon economy. In the above-mentioned Technical Summary, the IPCC has stated that "Reduced deforestation and degradation is the forest mitigation option with the largest and most immediate carbon stock impact in the short term per hectare and per year globally." For California's cap-and-trade program, sector-based credits from avoided deforestation are a potentially promising opportunity for covered entities to reduce compliance costs while ensuring net reduction of GHG emissions to the atmosphere.

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[38] Paustian, K. et al. IPCC Guidelines for National Greenhouse Gas Inventories. Volume 4, Chapter 1, (2006). Found at: http://www.ipcc-nggip.iges.or.jp/public/2006gl/pdf/4_Volume4/V4_01_Ch1_Introduction.pdf. See Page 1-11, Box 1.1 Framework of Tier Structure for Agriculture, Forestry, and Other Land Use Methods.

[39] Nabuurs, G. J., O. Masera, et al. (2007). Forestry. Climate Change 2007: Mitigation of Climate Change. Contributions of Working Group III to the Fourth Assessment Report of the Intergovernmental Panel on Climate Change. M. Apps and E. Calvo. New York, Cambridge University Press. Found at: http://www.ipcc.ch/publications_and_data/ar4/wg3/en/ch9.html

Since 2008, California established itself as a leader in the REDD effort at the subnational level through the creation of and participation in the GCF process, creating global subnational partnerships and a blueprint for supporting eligible forest carbon activities in REDD programs. Subnational jurisdictions that are members of the GCF are home to 21 percent of the world's tropical forests, most of which are experiencing severe deforestation pressure for alternative uses, such as large-scale agriculture, and ranching.[40]

While REDD poses significant emissions mitigation opportunities, the concept is newly emerging, and it is imperative that California moves forward carefully with the goal of establishing a REDD model for subnational programs that is of high quality and replicable.

i. Setting a Framework and Criteria for Subnational REDD Programs

A protocol must be developed and approved by the Board to quantify, monitor, report, and verify emissions reductions achieved by REDD programs. To be considered for approval by the Board, a REDD program will need to be designed as closely to the following framework and criteria as possible:

- *REDD Plan*. The host jurisdiction's REDD program must be based on a forest sector plan that has been approved by the host jurisdiction and specifically:
    - Assesses the local drivers of deforestation in its jurisdiction; identifies reforms and policies to address these drivers; identifies emissions from deforestation; and identifies systems to be used for data collection, monitoring, and the development of institutional capacity necessary to implement a deforestation reduction program.

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[40] Gibbs, H. K. and J. O. Niles. 2010 (unpublished). Preliminary Estimates of Forest Area and Forest Carbon Stocks in Developing Country GCF States and Provinces. Tropical Forest Group Report for the Governors' Climate and Forest Taskforce (GCF). Boulder, CO. 2010. Based on: A. Ruesch, and H.K. Gibbs. 2008. New IPCC Tier-1 Global Biomass Carbon Map For the Year 2000. Available online from the Carbon Dioxide Information Analysis Center http://cdiac.ornl.gov, Oak Ridge National Laboratory, Oak Ridge, Tennessee.

Note: Carbon estimates are based on Ruesch and Gibbs (2008) spatial database of biomass carbon stored in above and belowground living vegetation, circa 2000, which was created following the International Panel on Climate Change (IPCC) Good Practice Guidance for reporting national greenhouse gas inventories. The team synthesized and mapped the IPCC Tier -1 default values using the GLC2000 global land cover map stratified by continent, ecoregion and forest disturbance level. The database is appropriate for regional to global assessments only and has not been validated with field data and therefore may be used for estimations. Spatial resolution is 1km by 1km.
http://cdiac.ornl.gov/epubs/ndp/global_carbon/carbon_documentation.html

- Establishes a timeframe for implementing the program and transitioning to low emissions development with respect to emissions from forest and land use activities.

- *Inventory*. The REDD program must utilize the most up-to-date and comprehensive accounting of sources and sinks available to the host jurisdiction, and is consistent with estimates of carbon stocks and emissions based on forest classes defined in the Intergovernmental Panel on Climate Change *Good Practice Guidance for Land Use, Land Use Change, and Forestry.*[41]

- *Reference Level*. The REDD program must set a GHG emissions reference level that represents a conservative estimate across a jurisdiction's forest sector. Staff's initial thinking is that this reference level should be derived from absolute deforestation based on historic emissions averaged over a 10-year period and adjusted if necessary.

- *Crediting Baseline*. The REDD program must set a crediting baseline based on specific targets for 2020 and beyond.

- *Nested Accounting*. If the program is nested, it must include the necessary infrastructure for clear reconciliation of project performance with the performance of the sector as a whole.

- *Retirement*. The program must include a retirement mechanism for removing the credits that have been used for compliance from the state-level accounting system, crediting baseline, and credits retired.

- *Public Participation and Participatory Management Mechanism*. The REDD program must established and incorporated an effective public participation and participatory management process that provides for the consultation and full involvement of forest-dependent communities in affected areas during the planning, design, implementation, monitoring, and evaluation of program activities.

- *Protection Against Reversals*. The REDD program must established a statewide forest sector performance insurance mechanism to ensure projects are not penalized for reversals against the jurisdiction's crediting baseline.

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[41] Good Practice Guidance for Land-Use, Land-Use Change and Forestry, (2003). Edited by Penman J., et al. Published by the Institute for Global Environmental Strategies (IGES) for the IPCC. Found at: http://www.ipcc-nggip.iges.or.jp/public/gpglulucf/gpglulucf_contents.html.

ii. Next Steps for REDD Implementation

In 2011, ARB will work closely with REDD technical experts, scientists, stakeholders, research institutes, and the Governors' Climate and Forests Task Force to address critical technical and policy issues in order to refine guidance for a high-quality subnational REDD program. Staff anticipates that REDD offset credits from Board-approved programs could enter the California market in 2015. Staff is, however, contemplating how pilot activities with host-jurisdictions closest to having program infrastructure in place could be considered for approval earlier than 2015. A pilot program or group of pilot programs could provide REDD credits sometime during the first compliance period.

IV ANALYSIS OF ALTERNATIVES TO THE PROPOSED REGULATION

This Chapter provides an analysis of the alternatives staff considered to the proposed cap-and-trade regulation. Part A describes the alternatives to implementing a cap-and-trade program. Part B describes the alternatives to some specific cap-and-trade program design features. For each of the alternatives, staff outlines the costs and benefits of the approach and explains why it chose to propose the cap-and-trade regulation and incorporated design features.

A. Alternatives to the Cap-and-Trade Program

Staff analyzed four alternatives to the proposed cap-and-trade regulation:

- Do not implement the cap-and-trade program, and do not replace it with an alternate approach to achieve additional emissions reductions (no project).
- Implement additional source-specific regulations designed to achieve the AB 32 goals in place of the cap-and-trade program.
- Implement a carbon fee in place of the cap-and-trade program.
- Link a California cap-and-trade program to a federal cap-and-trade program.

In evaluating these alternative approaches to the proposed regulation, ARB staff found that none were as, or more, effective than a cap-and-trade program in carrying out the goals of AB 32. Further, none of the options that would have enabled California to meet AB 32 goals were as cost-effective as the proposed cap-and-trade regulation. Staff provides a discussion of each alternative in the following sections.

1. Do Not Implement the Cap-and-Trade Program ("No Project" Alternative)

The "No Project" Alternative defines a scenario in which ARB would not implement a cap-and-trade program, and would not supplement the complementary measures identified in the *Climate Change Scoping Plan* to achieve the additional emissions reductions needed to meet the AB 32 emissions limit. Under this alternative, ARB would fail to meet its legal mandate to reduce GHG emissions to 1990 levels by 2020.

As part of the ongoing work to implement the Scoping Plan, ARB staff updated 2020 GHG emissions-reductions projections with estimates published in adopted regulations' staff reports. In addition, the baseline forecast and the reductions that would be achieved by the complementary measures were adjusted to account for the recent economic downturn. Measures that were not considered

likely to realize reductions within the 2020 timeframe were not included in emissions-reduction totals. In analyzing reductions that would occur under the No Project Alternative, staff considered only those measures that are adopted and those not-yet-adopted measures that are planned and reasonably foreseeable.

ARB Scoping Plan measures that have been adopted by the Board, pursuant to AB 32,[42] measures that are being implemented by other agencies and organizations,[43] and measures that are reasonably foreseeable[44] are currently projected to provide approximately 62 $MMTCO_2e$ in reductions in 2020. Given a 2020 baseline projection of 507 $MMTCO_2e$,[45] the No Project Alternative would result in emissions of 445 $MMTCO_2e$ in 2020—*at least* 18 $MMTCO_2e$ above the 427 $MMTCO_2e$ target. This gap could be significantly greater if adopted measures fail to achieve expected reductions, if energy-efficiency programs are not funded at adequate levels or are less effective than projected, or if the economy grows faster than expected. Based on this information, if the cap-and-trade regulation is not implemented, California's GHG emissions will not be reduced to 1990 levels by 2020, in violation of AB 32.

In addition, the cap-and-trade program is unique in setting a firm limit on emissions, rather than establishing performance standards and other mechanisms to reduce the emissions intensity of different activities. For most complementary measures, the emissions reductions will vary based on factors like economic and population growth. The firm limit on emissions established by the cap-and-trade program will help ensure that statewide emissions will meet the AB 32 target, even if implementation of the complementary measures results in greater remaining emissions than currently anticipated.

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[42] 33 percent Renewable Electricity Standard (part of E-3), Low Carbon Fuel Standard (T-2), Regional Targets (T-3), Tire Pressure Program (part of T-4), Ship Electrification (T-5), Port Drayage Trucks (part of T-6), Heavy Duty Aerodynamics (T-7), Medium/Heavy Hybridization (T-8), Energy Efficiency and Co-Benefits Audits for Large Industrial Sources (I-1), Motor Vehicle A/C (H-1), SF_6 Limits in Non-Utility and Non-Semiconductor Applications (H-2), Reduction of Perfluorocarbons in Semiconductor Manufacturing (H-3), Limit High GWP Use in Consumer Products (H-4), Refrigerant Tracking/Reporting/Repair Deposit Program (part of H-6), SF_6 Leak Reduction and Recycling in Electrical Applications (part of H-6), and Landfill Methane Control Measure (RW-1).

[43] High-Speed Rail (T-9), Energy Efficiency and Conservation (E-1), Million Solar Roofs (E-4), and Sustainable Forests (F-1).

[44] Advanced Clean Cars (formerly Pavley II, T-1).

[45] The revised 2020 baseline accounts for the economic downturn and includes the emissions reductions from Pavley I and the 20 percent renewable portfolio standard. For more details, see the revised 2020 baseline forecast at ARB's "Greenhouse Gas Inventory - 2020 Forecast" webpage: http://www.arb.ca.gov/cc/inventory/data/forecast.htm.

2. Implement Only Additional Source-Specific Command-and-Control Regulations

Another alternative to adopting the cap-and-trade regulation would be to implement additional source-specific command-and-control regulations that would achieve the same level of GHG emissions reductions as that of the proposed cap-and-trade program. If this alternative were pursued, ARB would likely focus primarily on the industrial sector because the transportation, electricity, and natural gas sectors are already extensively addressed[46] through complementary Scoping Plan measures.

Command-and-control regulations would not provide the same assurance of reductions as that offered by a cap-and-trade program. Emissions reductions from command-and-control regulations are estimates based on assumptions about the specific regulation, and typically result from reducing the emissions intensity of the activity that is regulated. These assumptions may include forecasts of technology development and penetration estimates. Although these estimates would be based on the best data available, actual results may be significantly different because regulations may fail to achieve expected reductions, or programs may not be funded at adequate levels or may be less effective than projected. In addition, increases in the regulated activity (e.g., an increase in throughput) could mean that the regulation has the effect of reducing emissions intensity but the absolute level of emissions could actually increase. A cap-and-trade program, on the other hand, would establish the maximum level of total GHG emissions allowed to be emitted collectively by all covered sources. Because the proposed cap-and-trade program sets a cap on the GHG emissions from the majority of California's GHG emissions, it helps ensure that the State will meet the AB 32 statewide emissions limit.

Command-and-control regulations would also not allow for a demand-side response to an allowance price signal across the entire economy. The price signal established through a cap-and-trade program would provide an incentive for investment in energy efficiency and clean fuels, and would also drive efficiency and conservation in consumer and residential energy use beyond that required through the Scoping Plan's complementary measures.

Source-specific regulations are also unlikely to be as cost-effective at reducing GHG emissions as the proposed cap-and-trade program. The cap-and-trade program is designed to allow covered entities to find the most cost-effective GHG emissions reductions by reducing their GHG emissions, buying allowances from

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[46] The transportation, electricity, and natural gas sectors provide over 80 percent of total adopted and foreseeable 2020 reductions from complementary measures; whereas, the industrial sector provides less than 1 percent of these reductions.

an entity that does not need them for compliance, or purchasing offset credits. With source-specific regulations, entities must comply with the regulation, no matter what it costs. Even though each source-specific regulation must undergo cost-effectiveness analyses, it may not necessarily be the most cost-effective for the industry and economy as a whole because cost-effective reductions are not necessarily evenly distributed through all industrial sectors.

In addition to lacking emissions-reductions certainty, and having the potential to be less cost-effective at reducing emissions, industry-wide command-and-control regulations would be challenging to draft and implement. To develop these regulations, ARB would need to identify and target specific processes and equipment and formulate regulations for each. Due to the diverse nature of many industrial processes and a lack of data, it is not practical for ARB to craft and implement such regulations at this time.

The petroleum refining sector, which is the largest industrial GHG emissions source, provides a good example of the complexity of crafting such regulations. As noted by Sweeney and Wyant et al. (2008), "The complex and heterogeneous nature of refineries and their operations cause significant variation in the amount of opportunity and cost of mitigation through efficiency improvements. Thus, a bottom-up approach where individual refineries are examined would be needed to precisely quantify the amount of GHG reduction through efficiency improvements."[47] Worrell and Galitsky (2005) make a similar point: "Every refinery and plant will be different. The most favorable selection of energy efficiency opportunities should be made on a plant-specific basis."[48] Thus, to effectively regulate petroleum refining, plant-specific data and requirements would be needed. Because ARB does not have access to such data at this time, it would be impossible to develop these requirements. Additionally, developing, implementing, and enforcing plant-specific regulations would be resource intensive.

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[47] Sweeney, Jim, John Weyant, et al. 2008. *Analysis of Measures to Meet the Requirement of California's Assembly Bill 32.* Precourt Institute for Energy Efficiency, Stanford University.

[48] Worrell, Ernst, and Christina Galitsky. 2005. *Energy Efficiency Improvement and Cost Saving Opportunities for Petroleum Refineries.* Lawrence Berkeley National Laboratory. http://escholarship.org/uc/item/96m8d8gm (accessed September 22, 2010).

3. Carbon Fee

Another alternative to the cap-and-trade regulation is to place a per-metric-ton fee on GHG emissions from covered sources. Both a carbon fee and a cap-and-trade program would incentivize GHG emissions reductions by pricing those emissions, and ARB would expect to see similar types of emissions-reduction approaches under either pricing scheme. The major benefit of a carbon fee is that it provides price certainty for covered entities; with a cap-and-trade program, the major benefit is environmental (GHG emissions) certainty. The greater certainty in meeting the emissions goals provides an important policy reason to prefer the cap-and-trade program over a carbon fee approach. In addition, the cap-and-trade program proposed in this regulation includes a number of features designed to provide some predictability in cost, including limited use of offsets, banking, and an allowance reserve and reserve price.

While covered sources would face more price certainty in a carbon fee program, the sources covered by a cap-and-trade program can still plan effectively because they know what they would need to spend to reduce emissions. The sources can weigh those costs against the expected cost of compliance instruments and the long-term need to reduce emissions as part of business planning. A cap-and-trade program is the preferred approach because it ensures that technologically feasible reductions occur with the lowest marginal cost of control.

A carbon fee does not provide the same level of certainty in emissions as that provided by a cap-and-trade program. While economic modeling can estimate the marginal cost of abatement for emissions reductions, it cannot predict exactly how high the fee must be set to discourage emission sources from simply paying the fee instead of reducing their emissions to a level envisioned by the program. If the carbon fee is set too low, not enough reductions will take place and California will not meet the AB 32 goals. If the carbon fee is set too high, a greater amount of reductions would take place than would be necessary to comply with the program requirements, which increases the cost of the program to covered entities.

Adoption of a carbon fee would also not avoid many of the complexities associated with implementing a cap-and-trade program, since it would still require reporting, monitoring, and verification of covered entities' GHG emissions. ARB would also still be required[49] to minimize emissions leakage to the extent feasible. Because adding any price on carbon could increase the potential for emissions leakage from emissions-intensive, trade-exposed industries, rules and protocols for managing leakage would need to be developed under both a carbon

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[49] HSC §38562 (b)(8).

fee and a cap-and-trade regulation. The proposed regulation includes a number of features designed to achieve this end, including substantial free distribution of allowances in the early years of the program, and many features designed to help contain costs.

While some may argue that a carbon fee would provide a more predictable source of income for the State to put toward the furtherance of AB 32 goals, staff believes that the predictability of carbon fee revenue streams is neither guaranteed nor exclusive to this approach. Revenues generated by a carbon fee may be more predictable than those from a cap-and-trade program, but revenues can also be generated under a cap-and-trade program to the extent that allowances are auctioned. The cap-and-trade regulation mandates a minimum Reserve Price for allowances, guaranteeing revenue for all auctioned allowances. Further, cap-and-trade program auction prices also send an important signal that reflects the ease or difficulty of meeting program goals. Low auction prices would reflect low demand for permits, meaning that sources are able to collectively reduce emissions to meet the emissions limits at low cost. While the program would generate relatively lower revenues if auction prices are low, less revenue would be needed to implement AB 32 because the AB 32 targets were being met. If sources are having difficulty meeting the targets, there would be higher demand for allowances and higher prices at auction. Under these circumstances, higher revenues would be generated that could be used to invest in additional measures to help meet the AB 32 emission targets. It is important to note that the measures in the Scoping Plan are designed to reduce GHG emissions, not to raise money.

Staff notes that implementing a carbon fee combined with a cap-and-trade program is possible. Indeed, British Columbia, a WCI partner, currently has a carbon fee and is planning to start a cap-and-trade program in 2012. Staff believes that the proposed cap-and-trade program design provides acceptable price certainty[50] while assuring that emissions do not exceed the 2020 target.

4. California Cap-and-Trade Program Linked with a Federal Cap-and-Trade Program

ARB is moving forward with its development of a cap-and-trade regulation while federal climate change legislation has stalled in Congress, leaving no prospect of a federal GHG cap-and-trade program in the near term.[51] With no federal cap-

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[50] The cost-containment reserve mechanism sets a soft ceiling of prices, keeping them within a known range in most scenarios. (See Appendix G for more details.)

[51] The American Clean Energy and Security Act of 2009 was passed by the U.S. House of Representatives in June 2009, but no legislation was passed by the Senate. Several climate, clean energy, and energy-efficiency bills have been introduced in the Senate this year, but as of the beginning of October 2010, no vote is expected during this Congress, and prospects for action on economy-wide climate change legislation in the next Congress is unclear.

and-trade program anticipated in the near future, ARB will continue to move ahead with the proposed California program designed to meet the AB 32 goals, and to work toward linking that program with programs developed by our WCI partners. If ARB waited for a federal cap-and-trade program to link with, it is possible that California would fail to meet the AB 32's 2020 target.

The major federal proposals in recent years included some form of a moratorium on state or regional cap-and-trade programs in the United States. If a federal cap-and-trade program is adopted that preempts any subnational cap-and-trade programs, California, along with other states participating in regional programs (e.g., Western Climate Initiative, Regional Greenhouse Gas Initiative, and the Midwestern Regional Greenhouse Gas Reduction Accord) will work to transition their programs to a national program.

At the federal level, California has continued to promote appropriate recognition of early actions taken by states to reduce GHG emissions. States that have taken early action through the establishment of cap-and-trade programs, including programs that fund GHG-reduction activities, should not be disadvantaged if a federal program is implemented. Should a federal cap-and-trade program be established that preempts California's program, staff supports the establishment of a mechanism for the exchange of State-issued allowances for federal allowances to provide for an orderly transition and avoid the creation of stranded allowances.

B. Alternatives to Specific Cap-and-Trade Program Design Features

Staff analyzed specific alternatives to the design of the cap-and-trade regulation. These design elements include the following:

- Border adjustments.
- Different offset limit.
- 100 percent auction of allowances.
- No banking of allowances.
- Not linking to other cap-and-trade programs.
- Facility-specific caps.
- Restricting trading in adversely affected communities.

1. Border Adjustments

Staff explored two options, both recommended by the Economic and Allocation Advisory Committee (EAAC),[52] for reducing the risk of emissions leakage in the cap-and-trade program: border adjustments and output-based free allocation. *Border adjustments* are a way to place a price, in the form of allowances or dollars, on the GHG emissions associated with imports. They are meant to create a level playing field when regulations vary across jurisdictions. In contrast, under *output-based free allocation,* facilities receive free allocation of allowances based on their output and an industry emission benchmark. Staff compared output-based free allocation to border adjustments and concluded that output-based free allocation is a superior approach for non-electricity goods because it does not face the considerable technical and legal difficulties that border adjustments face. For electricity, staff chose to utilize a border adjustment in the form of the first deliverer compliance obligation because the requisite data are available, and because of the express direction in AB 32 to address electricity imports.

Under the first deliverer approach, the entity that first delivers a good into the State would be responsible for the compliance obligation for the emissions associated with manufacture and transport of those goods. ARB has chosen to utilize the first deliverer approach to regulate emissions associated with electricity generated in another jurisdiction but consumed in California. This approach is possible for electricity because significant information is available on the generation and distribution of electricity with the Western Electric Coordinating Council system, which covers all imported electricity consumed in California.

Staff chose not to extend the first deliverer approach to include entities that import non-electricity goods into California from out-of-state because of potentially significant technical and legal challenges. The first deliverer approach is effective if detailed production data are available on both the imported goods themselves and the entities producing them. Because goods are often traded several times before entering the California market, determining the associated GHG emissions could be exceedingly difficult. The application of border adjustments to interstate and international trade would also face legal scrutiny under the Commerce Clause[53] and World Trade Organization principles.[54]

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[52] Economic and Allocation Advisory Committee. March 2010. *Allocating Emissions Allowances under a California Cap-and-Trade Program: Recommendations to the California Air Resources Board and California Environmental Protection Agency.*

[53] Article I, Section 8, Clause 3 of the United States Constitution.

[54] World Trade Organization (WTO) principles require that the cap-and-trade program must have the capacity to assign or verify emissions associated with the goods produced in California and in foreign countries in exactly the same manner. There is increasing consensus in the international community that border adjustments may be implemented in a manner compatible with WTO

In the Preliminary Draft Regulation, staff discussed the possibility of using a lifecycle analysis (LCA) calculation for transportation fuels' compliance obligations. The LCA approach is a type of border adjustment for imported fuels. While this approach is being used in ARB's Low Carbon Fuel Standard (LCFS), significant additional work would be needed to account for emissions that are included in the LCA and are also proposed to be covered under the cap-and-trade program. Staff chose not to apply LCA in the cap-and-trade program, but instead chose to calculate compliance obligations from direct combustion emissions because of the challenges of netting out stationary emissions across emissions categories. Staff's proposed approach allows for greater administrative simplicity, and does not interfere with the goal of reducing life-cycle emissions from transportation fuels that the LCFS is designed to achieve.

Because of the technical and legal challenges involved with border adjustments, ARB has chosen to utilize free allocation of allowances to entities at risk of leakage. The proposed method of allocation used is output-based, updated, free allocation and was recommended by EAAC. For more information on the proposed allocation program, see Appendix J: Allowance Allocation.

As part of implementation of the cap-and-trade program, ARB will monitor whether leakage is occurring. Should ARB find that leakage is occurring despite the safeguards in the regulation, ARB will examine what additional safeguards, possibly including border adjustments, should be implemented.

2. Different Offset Limit

In the *Climate Change Scoping Plan,* ARB proposed setting the offset limit such that a majority of emissions reductions come from capped sectors. In the Preliminary Draft Regulation, staff converted this offset reduction to a limit of 4 percent of each covered entity's compliance obligation. In this proposed cap-and-trade regulation, this percentage was increased by 4 percent, for a total of 8 percent, to compensate for allowances removed from general circulation to populate the Allowance Price Containment Reserve.[55] Staff explored two alternatives to the 8 percent-of-compliance-obligation offset limit for complying entities in the cap-and-trade program: not allowing use of offset credits, and allowing unlimited use of offset credits

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requirements; however, because border adjustments are still associated with significant uncertainty, staff proposes to use output-based free allocation to address emissions leakage.

[55] For further discussion of the Allowance Price Containment Reserve Account, see Chapter II, part H (Allowance Allocation), subpart 1 (Establishment of an Allowance Price Containment Reserve) of this volume.

ARB's *Updated Economic Analysis of California's Climate Change Scoping Plan*[56] showed a large increase in the price of 2020 allowances if offsets are not allowed into the system. For this reason, ARB staff has chosen to allow the use of offsets—up to the specified limit—for compliance in the proposed cap-and-trade program.

While offsets provide significant benefits (providing low-cost emissions reductions, flexibility in achieving reductions, and incentives to reduce emissions in sectors otherwise difficult to regulate), allowing unlimited use of offset credits would reduce the amount of GHG emissions reductions occurring directly within the sectors covered by the cap-and-trade program. This approach could reduce local economic, environmental, and public health co-benefits, and delay California's transition to a low-carbon economy. This transition is critical to meet California's long-term GHG emissions reductions goals. Because of this, staff has opted to allow entities to cover up to 8 percent of their individual compliance obligations with offset credits.

ARB analysis of the potential emissions impacts of the cap-and-trade regulation[57] indicates that California's existing programs to meet federal air quality standards will provide the majority of criteria pollutant reductions with further NO_x reductions ranging from about 15 to 45 percent by 2020. In communities that ARB evaluated, the cap-and-trade regulation has the potential to provide small additional criteria pollutant reductions in the range of 1 to 3 percent if all greenhouse gas reductions were implemented locally. Because offsets provide more compliance instruments and lower the price, some entities may choose not to reduce greenhouse gas emissions on-site. In this case, the communities evaluated would still experience 15 to 45 percent NO_x reductions by 2020.

3. 100 Percent Auction of Allowances

Allowances can either be distributed freely to covered entities, sold through an auction, or through a combination of the two. EAAC recommended addressing leakage through free allocation, and relying on auction for distribution of the remaining allowances. In developing the cap-and-trade program, staff determined that a soft start for the program under the current economic conditions dictates greater reliance on free allocation of allowances in the early years of the program. Staff views this free allocation as critical to avoid adding an immediate cost to covered industries that could inhibit their ability to invest in emissions reductions. As the program progresses, staff propose a transition to a

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[56] *Updated Economic Analysis of California's Climate Change Scoping Plan: Staff Report to the Air Resources Board.* March 24, 2010. http://www.arb.ca.gov/cc/scopingplan/economics-sp/updated-analysis/updated_sp_analysis.pdf (accessed September 23, 2010).

[57] See Appendix P for more details.

heavier reliance on auction for allowance distribution while still minimizing leakage where risk exists.

Because of the risk of leakage for emissions-intensive, trade-exposed (EITE) industries, staff has chosen to employ free allocation to minimize leakage risk. (See "Border Adjustments," above, for more information.) EITE industries will receive free allocation of allowances for as long as the risk of leakage exists. For the first compliance period, the proposed program also includes allocation of the majority of allowances required to fulfill compliance obligations for free, not just to EITE industries, but also to non-EITE industries and to the electricity sector. The remaining allowances will be auctioned.

An alternative approach would be to auction 100 percent of allowances at the beginning of the program. Staff has rejected this approach for two reasons. First, to avoid economic dislocation, covered entities need time to plan for and invest in ways to reduce their emissions in a cost-effective manner. Second, a large portion of free allocation is necessary due to the uncertainty associated with covered entities' ability to pass through costs to consumers and remain competitive.

4. No Banking of Allowances

The proposed cap-and-trade regulation allows for unlimited banking of allowances. Allowances, once issued, do not expire. Banking provides market stability during times when emissions may fluctuate due to weather or economic conditions. In such cases, banking helps to prevent large fluctuations in allowance price during these periods of emissions variation. Banking also helps provide price stability by assuring that allowances will retain their value, and gives covered entities a stake in the continued operation of the program because allowances are a financial asset. A positive impact of allowing banking is that it incentivizes firms to over-comply in early compliance periods.

Staff rejected the alternative of disallowing banking of allowances because it provides no financial or environmental benefits and would not necessarily increase the environmental integrity of the program.

5. Not Linking to Other Cap-and-Trade Programs

The proposed cap-and-trade regulation allows potential future linkage with external greenhouse gas emissions trading systems (GHG ETS), including those of WCI partner jurisdictions. Linking with external GHG ETS's involves jurisdictions accepting one another's allowances and offsets for compliance, creating a regional market. Linkage would increase the total supply of compliance instruments, which would reduce compliance costs for California's covered entities.

As proposed, the cap-and-trade regulation does not link with any external GHG ETS. Future linkage would require regulatory action by the Board supported by a case-by-case analysis, including an environmental analysis. Several options

exist for how linkage with WCI partner jurisdictions or other GHG ETS's might occur (e.g., unilateral linkage,[58] bilateral linkage[59]) but are not explored here.

Staff rejected the option of precluding linkage with external cap-and-trade programs because linkage can lead to significant reductions in compliance costs associated with increasing the supply of compliance instruments. While linkage would require California to forfeit some control over where the reductions occur (i.e., out of state versus in state), staff believes the increased cost-effectiveness of the program that should result from a more liquid and better-functioning market for California's covered entities offsets the possibility of fewer in-state reductions.

6. Facility-Specific Caps

An alternative to an overarching cap for covered entities and sectors would be to have facility-specific declining caps. This would ensure that each facility would reduce its proportional share of emissions. Under such an option, ARB would need to identify the specific facilities that would be covered by the program, conduct an appropriate analysis to support a specific cap for each facility, and consider whether the reduction requirements established by the declining cap for that facility would be cost-effective. Such a program would be extremely difficult to apply to imported electricity or to distributed use of fuels, so that the overall scope of the program would likely be need to be limited to industrial facilities and in-state power plants.

Facility-specific caps would diminish the flexibility of these facilities to meet the GHG reduction goals. In a standard cap-and-trade program, facilities can either reduce emissions or buy allowances from other facilities that do reduce emissions. Restricting trading leaves only one compliance option: reduce emissions on-site through increasing efficiency, modernizing equipment, changing to cleaner fuels, or reducing production. If the cap for all facilities declined at the same rate, individual facilities might not have cost-effective options, especially if they seek to expand production to meet increased demand. Establishing caps that decline at different rates at different facilities would require ARB staff to conduct a detailed analysis to determine what, if any, cost-effective options were available at each covered facility.

Reducing the flexibility of trading allowances would increase the cost of the program. With facility-specific caps, no market would exist that allowed entities to trade allowances and achieve the lowest-cost reductions. Facilities with large amounts of low-cost reductions would have little incentive to over-comply, while

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[58] Unilateral linkage would allow the covered entities from one jurisdiction to use compliance instruments from a linked program, but would not allow covered entities from the linked jurisdiction to use allowances and offset credits issued by the first jurisdiction.

[59] With bilateral linkage, compliance instruments are fully fungible between linked programs.

facilities with a limited number of reduction opportunities would have to implement expensive reduction strategies. Thus, staff has rejected this alternative because of the increased cost of implementing the program across the economy.

Although facility-specific caps would ensure that emissions reductions occur in specific communities, ARB's analysis[60] indicates that California's existing programs to meet federal air quality standards will provide the majority of criteria pollutant reductions with further NO_x reductions ranging from about 15 to 45 percent by 2020. In communities that ARB evaluated, the cap-and-trade regulation has the potential to provide small additional criteria pollutant reductions in the range of 1 to 3 percent if all greenhouse gas reductions were implemented locally. Although ARB staff does not predict that the cap-and-trade regulation will result in emissions increases, our examination of the potential impacts of facility growth, for any reason, shows that in the context of total community emissions, these increases would be very small, reducing the expected 15 to 45 percent reduction by 2020 by 2 percent or less.

7. Restricting Trading in Adversely Impacted Communities

Restricting trading in adversely affected communities is a design option to reduce potential negative impacts of cap-and-trade. By restricting trading in communities with heavy localized air pollution, local facilities must reduce their share of emissions. This design option is similar to facility-specific caps but applied only to discrete locations.

Although restricting trading in adversely affected communities would ensure that emissions reductions occur in specific communities, ARB's analysis[61] indicates that California's existing programs to meet federal air quality standards will provide the majority of criteria pollutant reductions, with further NO_x reductions ranging from about 15 to 45 percent by 2020. In communities that ARB evaluated, the cap-and-trade regulation has the potential to provide small additional criteria pollutant reductions in the range of 1 to 3 percent, if all greenhouse gas reductions were implemented locally. Although ARB staff does not predict that the cap-and-trade regulation will result in emissions increases, our examination of the potential impacts of facility growth, for any reason, shows that in the context of total community emissions, these increases would be very small, reducing the expected 15 to 45 percent reduction by 2020 by 2 percent or less.

Restricting trading among participants increases the cost to comply with the program. A cap-and-trade program gives entities the option of decreasing

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[60] See Appendix P: Co-Pollutant Emissions Assessment for more details.
[61] See Appendix P: Co-Pollutant Emissions Assessment for more details.

emissions at the facility or buying allowances from another entity that reduced emissions. In limiting these options by reducing trading, emissions reductions are mandated at that entity. This limits the market to find the lowest-cost compliance pathway. Staff feels the potential limited environmental benefits of restricting trading in adversely affected communities do not outweigh the increased cost to comply with the proposed regulation.

V COMPLIANCE PATHWAYS SCENARIOS

A. Introduction

The California cap-and-trade program is proposed to be a flexible, market-based regulation designed to reduce greenhouse gas (GHG) emissions. The program neither mandates nor prohibits the use of specific technologies to achieve these reductions. The scenarios described in this Chapter demonstrate that covered entities will be able to comply with the cap-and-trade program using a variety of currently available GHG reduction strategies. Further, numerous abatement strategies exist, and compliance is not contingent upon the availability of only a limited number of abatement strategies.

Compliance pathways demonstrate which strategies covered entities could utilize (i.e., what "paths" they could travel) to comply with the cap-and-trade regulation. Staff developed compliance pathways for four scenarios, each with different assumptions about the availability of GHG abatement opportunities and the pathways that covered entities would use to achieve the GHG emissions cap. Each scenario includes enough emissions abatement opportunities to meet the AB 32 goal.

Staff developed four scenarios that illustrate the range of pathways that capped entities could follow to meet their compliance obligations and collectively achieve the cap. Staff believes that Scenario 1 (full abatement potential from complementary policies and full availability of offsets) is the most likely scenario, as it includes staff's best estimates of complementary measures and offset potential achieved within the 2012–2020 timeframe. In this scenario, 43.3 $MMTCO_2e$ of the required 74.6 $MMTCO_2e$ of reductions in 2020 would be achieved directly through the complementary measures, and 31.3 $MMTCO_2e$ of reductions would be achieved through the price signal imposed by the cap-and-trade program. At this level of abatement, the allowance price would be $20/metric ton in 2020—a price considered to be achievable by covered entities.

In Scenarios 2 and 3, in which offset supply (Scenario 2) and complementary policy reduction estimates (Scenario 3) would be decreased, allowance prices would increase to $40/metric ton in 2020. However, in Scenario 4, in which both complementary policy reduction estimates and offset potential would be reduced, large price increases would occur. This increase comes from the resulting requirement that many of the emissions reductions must come from consumers Analysis.

B. Relationship between Compliance Pathways Analysis and Economic Analysis

The compliance pathways presented here complement the abatement estimates from more comprehensive models such as Energy 2020. The compliance pathways scenarios should be used in conjunction with the economic analysis provided in Chapter VIII: Economic Impacts of the Proposed Regulation. The

compliance pathways and economic analyses estimate the cost of compliance with the proposed cap-and-trade regulation using different models and methods.[62] Limitations of the compliance pathways analysis include difficulty harmonizing assumptions and inputs across all abatement activities, and that interaction effects between abatement activities are not taken into consideration. This analysis also does not account for implementation obstacles such as compliance with New Source Review regulations for criteria pollutants, availability of fuels and feedstock, and other environmental requirements.

This analysis should be viewed as illustrative of possible strategies and scenarios for reducing emissions consistent with the declining cap. It is flexible in that assumptions about abatement strategies can be easily modified, and transparent in that all assumptions about abatements strategies are clearly defined. Information about the assumptions, as well as references to supporting data, are described in detail in Appendix F: Compliance Pathways Analysis.

C. Baseline Forecast and Required Reductions

The AB 32 baseline forecast of emissions from California capped sectors is given in Table V-1and presented graphically in Figure V-1. The baseline forecast represents an update of the GHG emissions inventory forecast used in developing the Scoping Plan. The forecast used the economic and energy forecasts from the California Energy Commission's 2009 Integrated Energy Policy Report,[63] which reflects the current economic downturn. Consistent with the updated economic analysis of the Scoping Plan completed in March 2010,[64] this baseline also assumes implementation of the existing California vehicles standards and the 20 percent Renewable Portfolio Standard. Other Scoping Plan measures are assessed in the compliance pathways analysis presented here, and so are not included in the baseline forecast. The difference between the baseline emissions forecast and the cap determines the GHG abatement necessary to meet the cap.

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[62] The economic analysis uses energy and macroeconomic models, while this analysis uses a bottom-up approach based on information about existing technologies.

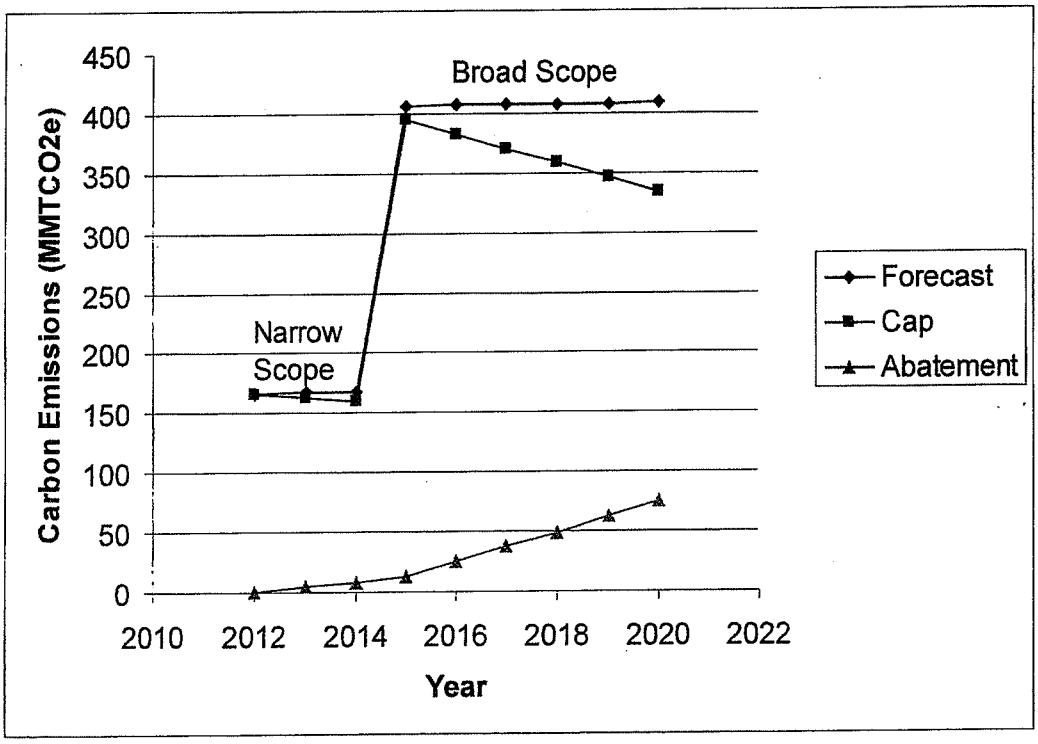
[63] California Energy Commission. 2009 Integrated Energy Policy Report, Final Commission Report, CEC -100-2009-003-CMF. http://www.energy.ca.gov/2009publications/CEC-100-2009-003/CEC-100-2009-003-CMF.PDF (accessed October 25, 2010).

[64] *Updated Economic Analysis of California's Climate Change Scoping Plan: Staff Report to the Air Resources Board.* March 24, 2010. http://www.arb.ca.gov/cc/scopingplan/economics-sp/updated-analysis/updated_sp_analysis.pdf (accessed September 23, 2010).

Table V-1: Baseline Emissions, Cap Level, and Abatement Required to Achieve the Cap.

	GHG Emissions ($MMTCO_2e$)		
Year	Forecast for Sources in the Cap-and-Trade Program	Cap	Annual Abatement Needed
2012	165.8	165.8	0.0
2013	167.3	162.8	4.5
2014	168.1	159.7	8.4
2015	406.7	394.5	12.2
2016	406.9	382.4	24.5
2017	407.6	370.4	37.2
2018	407.6	358.3	49.3
2019	408.4	346.3	62.1
2020	408.8	334.2	74.6

Figure V-1: Baseline Emissions, Cap Level, and Abatement Required to Achieve the Cap



D. Scenarios Analyzed

Staff developed four scenarios to illustrate the range of potential pathways that capped entities could follow to meet their compliance obligations and collectively achieve the cap. These are discussed in detail below. In each scenario, the entities collectively meet the regulating cap in the proposed regulation.

Staff varied assumptions about the effect of complementary policies and offset supply to create different scenarios. For complementary policies, staff explored two scenarios: (1) full abatement potential from complementary measures consistent with estimates in staff reports and the Scoping Plan, and (2) reduced abatement potential from complementary measures. For offsets, staff also explored two potential supply scenarios that varied the number of available offset credits: (1) sufficient offsets were available to meet the 8 percent limit in the regulation, (2) offsets were only available to meet 4 percent of entities' compliance obligations.

Based on implementation status, past experience, and current estimates of offset supply, staff believes that the most likely scenario is Scenario 1 (full abatement potential for both complementary measures and offsets) and the least likely scenario is Scenario 4 (partial abatement potential from complementary policies and offsets). Scenario 4 could occur if implementation of complementary measures were delayed due to legal action, if non-regulatory complementary measures were not as effective as originally estimated, if economic growth meant that reduced emissions intensity from the measures in the Scoping Plan still resulted in higher remaining emissions than estimated, and/or if offset projects did not materialize as expected by staff. Staff chose to analyze a full range of scenarios in order to illustrate how the cap could be met under a variety of assumptions. The next sections describe the assumptions for each of the four scenarios.

1. **Scenario 1: Full Complementary Policies, Full Offsets**

Scenario 1 assumes that full abatement potential is available from all sectors and all complementary policies, and reflects an offset supply equal to the offset quantitative limit.

2. **Scenario 2: Full Complementary Policies, Partial Offsets**

Scenario 2 assumes full abatement from the complementary policies and a reduced availability of offsets.

3. **Scenario 3: Partial Complementary Policies, Full Offsets**

In Scenario 3, staff explores a reduced abatement potential from the complementary policies and reflects and offset supply equal to the offset quantitative limit.

4. **Scenario 4: Partial Complementary Policies, Partial Offsets**

In Scenario 4, staff explores reduced abatement potential from complementary policies, and assumes a limited supply of offset credits.

E. Development of Abatement Cost Curves

1. Introduction

Abatement cost curves, or *supply curves,* provide a means to graph the impacts and costs of numerous abatement strategies. In the context of this analysis, *abatement* refers to greenhouse gas emissions reductions. The cost of each strategy is measured in dollars per metric ton of CO_2 equivalent ($MTCO_2e$) reduced. In these figures, the x-axis represents the annual GHG abatement potential, and the y-axis represents the cost of the strategy in dollars per metric ton. Strategies are plotted in blocks, with the width of the block representing the maximum potential GHG reduction, and the height representing the average cost in dollars per $MTCO_2e$ reduced. Strategies are organized by cost from least to greatest, and plotted adjacent to one another. Thus, the abatement strategies are sorted to give an idea of how the cost of strategies compare to each other. An example of an abatement cost curve for GHG reductions is shown in Figure V-2 and described below.

Figure V-2: Example 2020 Abatement Curve

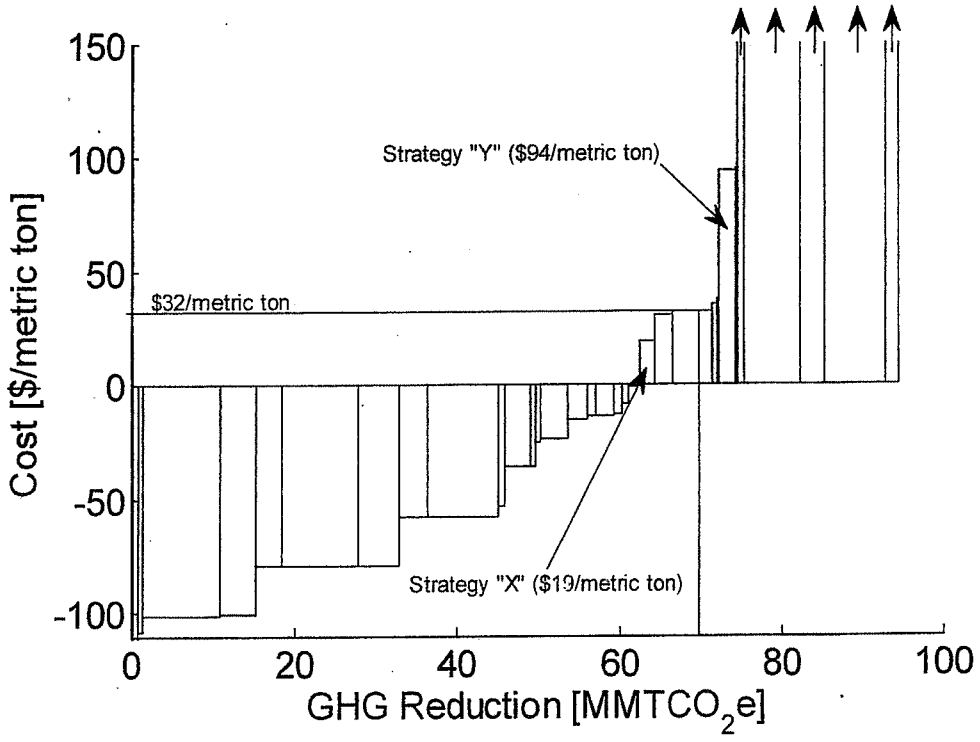


Figure V-2 shows an example abatement curve for a set of hypothetical GHG abatement strategies. Some costs are negative, denoting that the strategy saves money annually—usually from a decreased fuel cost from the baseline case. Thus, the strategy will pay for itself over its lifetime. Positive costs show that the strategy does not save money annually, usually caused by a combination of high

capital expenditures and low fuel reduction. These strategies will not pay for themselves over the life of the strategy in the absence of a cap-and-trade regulation.

Abatement curves are used to evaluate which abatement strategies might occur under a California cap-and-trade program. To use the curve to analyze a cap-and-trade scenario, a line is drawn at the amount of GHG reductions required. An example is shown in Figure V-2. In this illustration, achieving the 2020 cap would require approximately 70 $MMTCO_2e$ in reductions from the baseline case. This is illustrated by drawing a vertical line at a reduction of 70 $MMTCO_2e$. At the intersection of the GHG reduction line and the cost curve, a horizontal line is drawn, estimating the marginal cost of GHG emissions reductions; that is, the cost to reduce one more metric ton of GHG emissions. In the example case, the marginal cost is $32/metric ton. The analysis assumes that all abatement strategies to the left of the curve will be implemented because those strategies are less expensive than the marginal price. Thus, strategy "X," which costs $19/metric ton, is assumed to be fully implemented. All abatement strategies to the right of the vertical line are considered more expensive than the marginal price, and there is no economic incentive to develop these strategies. Thus strategy "Y," which costs $94/metric ton, is assumed not to be implemented.

2. Abatement Cost Curve Calculations

The abatement potential and cost of each GHG reduction strategy is calculated in reference to the baseline case, and therefore are dependent upon assumptions about the baseline forecast. Reductions are calculated by taking the difference between the emissions from the alternative strategy and the baseline forecast. Similarly, the capital costs and operation and maintenance (O&M) costs of a new strategy must be calculated with respect to what is being replaced. In most cases, the unit being replaced is similar to the new unit (i.e., a high-efficiency boiler replacing a low-efficiency boiler), and the change in O&M cost is negligible.

Greenhouse gas abatement is calculated by a reduction in combustion of fuel that would otherwise have been burned, a reduction in process emissions, or a combination of the two. Most GHG abatement strategies that are analyzed reduce GHG emissions by reducing the amount of fuel burned. Examples of these fuel-reduction strategies are increasing the efficiency of boilers and process heaters, increasing insulation, and purchasing more-efficient vehicles. The calculation of GHG reductions from reductions in fuel use are shown in Equation V-1.

Equation V-1: Greenhouse Gas Reduction Potential Calculation of Abatement Strategies

$$GHGR = (FuelUseNewStrategy - FuelUseBAUStrategy) * n * FI,$$

where *GHGR* is the greenhouse gas reductions, *FuelUseNewStrategy* is the annual fuel use of the new unit, *FuelUseBAUStrategy* is the annual fuel use of the unit that was replaced, *n* is the number total number of units installed, and *FI* is the fuel intensity of the fuel used, in $MTCO_2e$ per one million British thermal units (MMBTU).

Costs are calculated on an annual basis by summing annualized capital cost, O&M costs, and fuel savings and expenditures. Staff used discount rates to annualize the capital cost. The equation used to calculate the annualized capital cost is shown in Equation V-2:

Equation V-2: Annualized Capital Cost Equation

$$AnnualizedCapitalCost = CapitalCost \times \left(\frac{r}{1 - \frac{1}{(1+r)^t}} \right),$$

where *r* is the discount rate and *t* is the life of the capital in years.

Two discount rates are used to develop the abatement curves. For strategies adopted by the general public (e.g., vehicles and energy efficiency), staff assumed a discount rate of 5 percent. Staff assumed a discount rate for industry of 30 percent; this higher rate reflects industries' strategy to invest in abatement opportunities with shorter payback periods and under the constraint of limited availability of capital. The 30 percent discount rate for industry has been used in a number of studies.[65,66,67,68] The higher rate also ensures that additional costs are included that may not have been included in the capital cost, such as permitting costs.

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[65] Wagger, David. *Reducing CO_2 Emissions from California's Cement Sector.* Washington D.C.: Center for Clean Air Policy. 2005

[66] Bloomberg New Energy Finance. *Carbon Markets – North America – Research Note.* 2010

[67] Sathaye, Jayant, et al. Bottom-up Representation of Industrial Energy Efficiency Technologies in Integrated Assessment Models for the Cement Sector. Lawrence Berkeley National Laboratory, Environmental Energy Technologies Division. 2010.

[68] Xu, Tengfang, et al. *Development of Bottom-up Representations of Industrial Energy Efficiency Technologies in Integrated Assessment Models for the Iron and Steel Sector.* Lawrence Berkeley National Laboratory, Environmental Energy Technologies Division. 2010.

Costs on this study's abatement cost curve are measured in dollars per metric ton. By calculating abatement on a per-metric-ton basis, the costs of many abatement opportunities can be directly compared. The calculation is shown in Equation V-3:

Equation V-3: Dollars-per-Metric-Ton Cost Calculation of Strategies

$$Cost\left(\frac{\$}{MetricTon}\right) = \frac{TotalAnnualCostOfAltStrategy - TotalAnnualCostOfBAUStrategy}{GHGR},$$

where *TotalAnnualCostofAltStrategy* is the sum of the annualized cost of the new unit, *TotalAnnualCostofBAUStrategy* is the sum of the annualized cost of the old unit, and *GHGR* is the total annual GHG reductions as calculated by Equation V-1.

3. Abatement Strategies

A summary of the abatement options analyzed in this Chapter is shown in Table V-2. The abatement potential is split into five sectors: industrial, power, transportation, residential and commercial, and offsets. A summary of the sectors and strategies is included below. For more information on the reduction strategies, see Appendix F: Compliance Pathway Analysis.

Table V-2: Abatement Option Summary

Sector	Abatement Options	Sources[69]
Industrial	Steam Efficiency	U.S. Department of Energy
	Process Heat Efficiency	Lawrence Berkeley National Laboratory
	Fuel Mix	case studies
	Process Improvements	local air districts
Power	Renewables	Energy and Environmental Economics, Inc. (E3)
	Power Dispatch: Coal-to-Gas Switching	Economic and Allocation Advisory Committee (EAAC)
	Combined Heat and Power	
Transportation	Light-Duty Vehicle Fuel Efficiency	U.S. EPA VISION model
	Biofuels	U.S. Energy Information Administration fuel economy estimates
	Electrification	ARB EMFAC model
	Regional Transportation Targets	
Residential and Commercial Energy	Energy Efficiency	E3/Itron
	Consumer Demand Response	EAAC
Offsets	Methane Digesters	Climate Action Reserve & ARB estimates
	Forestry	
	Ozone Depleting Substances	

Abatement strategies available to the industrial sector include efficiency increases from steam systems and process heat systems, fuel changes, and process improvements. California industries analyzed were petroleum refining, oil and gas, food, wood products, chemicals, iron and steel, and cement. Staff relied on reports from the U.S. Department of Energy, Lawrence Berkeley National Laboratory, and local air districts, among others, to obtain estimates of industrial abatement potential.

Abatement strategies available to the power sector include increased renewable electricity, changes in power dispatch from coal power to gas power, and increased combined heat and power. Estimates of the abatement potential from these strategies were gathered from an Energy and Environmental Economics, Inc. (E3) report prepared for the California Public Utilities Commission.[70] The

[69] Specific references can be found in Appendix F: Compliance Pathways Analysis.

[70] Energy and Environmental Economics, Inc. (2010): Greenhouse Gas Calculator for the California Electricity Sector. http://www.ethree.com/documents/GHG%203.11.10/GHG%20Calculator%20version%203b_Final_to_Post_March2010.zip.

total abatement potential of renewable electricity was scaled to match the Renewable Electricity Standard (RES) that increases the proportion of electricity sales from renewables to 33 percent in 2020. For coal-to-natural gas dispatch changes, E3 provided a figure detailing the 2020 WECC dispatch under different allowance prices. Three 2020 allowance prices were chosen from this plot to represent the coal-to-gas switching: $50/metric ton, $80/metric ton, and $120/metric ton. These prices were chosen to be just above the consumer demand responses mentioned below.

Abatement from the transportation sector relied on ARB estimates from complementary measures, including the Low Carbon Fuel Standard (LCFS), Advanced Clean Car standards, Goods Movement, vehicle efficiency, Regional Targets, High Speed Rail, and Heavy- and Medium-Duty Hybridization and Aerodynamics.

Abatement from the residential and commercial sector includes energy efficiency and consumer demand responses. Electricity and natural gas efficiency abatement potentials were based on the work done by E3 and Itron.[71] Consumer demand responses are calculated from price elasticities of electricity and gasoline. That is, when the price of electricity and gasoline increase, consumers reduce demand for these goods. The consumer demand responses for electricity and gasoline are calculated for three allowance prices: $20/metric ton, $60/metric ton, and $100/metric ton. For each of these allowance prices, estimates are made about the increased price of electricity and gasoline. With the increase in prices, demand responses are calculated based on electricity and gasoline elasticities of -0.15 and -0.1, respectively.[72,73]

Offset protocols under consideration with this regulation include the U.S. Forest Projects Protocol, Urban Forest Projects Protocol, U.S. Ozone Depleting Substances Projects Protocol, and Livestock Manure (Digester) Projects Protocol. Abatement potentials of these reductions are based on ARB estimates. While ARB staff anticipates that additional offset protocols may be brought to the Board for approval in 2011 and beyond, no attempt was made in this analysis to consider the effect of additional offset supplies beyond the four protocols that are part of the current rulemaking.

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[71] Rufo, Michael W., and Alan S. North. *Assessment of Long-Term Electric Energy Efficiency Potential in California's Residential Sector.* California Energy Commission, PIER Energy-Related Environmental Research. CEC-500-2007-002.

[72] Hughes, Jonathan E., Christopher R. Knittel, and Daniel Sperling. 2006. *Evidence of a Shift in the Short-Run Price Elasticity of Gasoline Demand.*

[73] Bernstein, M. A., and J. Griffin. 2005. *Regional differences in the price elasticity of demand for energy.* RAND Corporation.

4. Abatement Curve Results

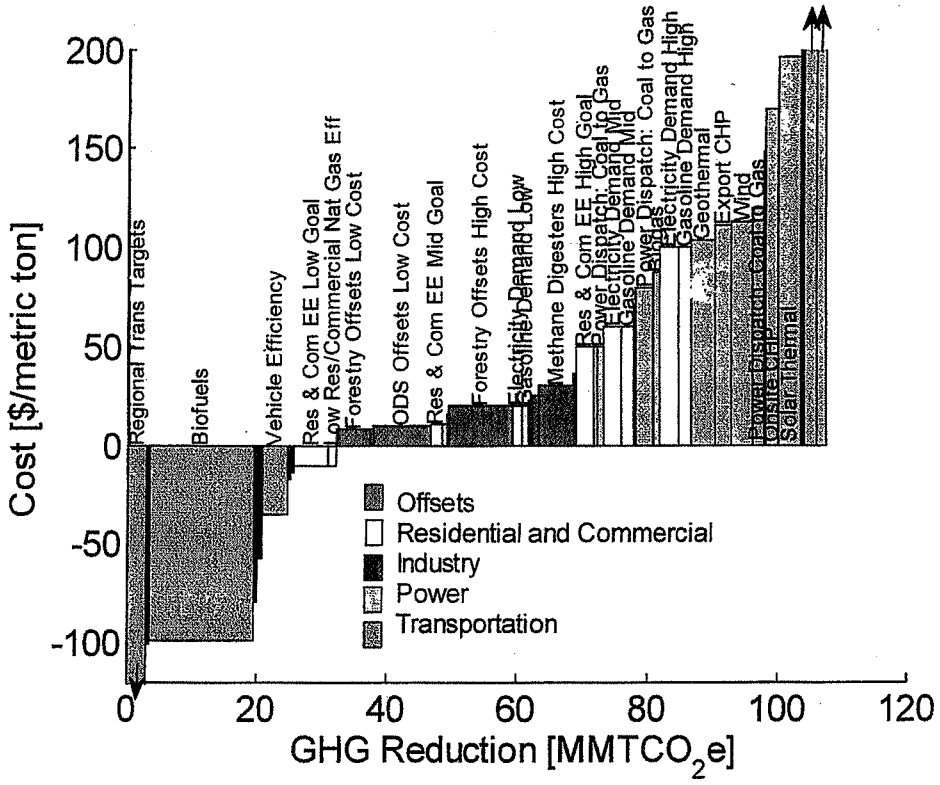
Three master abatement cost curves were constructed. The first curve includes all the potential abatement strategies that would be available to capped sectors, including those that would be used to meet complementary measure requirements. The second curve includes abatement strategies that would be driven by the cap-and-trade program price signal, but excludes abatement strategies required by other measures (e.g., LCFS, Advanced Clean Cars, Regional Targets, RES). The last abatement curve is a further subset of the abatement potential driven by the price signal, and it only includes industry abatement opportunities.

In each curve, two methods are used to differentiate strategies. For strategies that have a sufficiently large abatement potential, the name of the strategy is plotted over the strategy. By only placing a title on these large strategies, the curves are more legible and titles are not placed over one another. The other method of differentiating strategies is through color. In each curve, there is a legend of the colors used to describe the types of abatement opportunities

a. Total Capped Sector Abatement Potential

The Total Capped Sector Abatement Potential shown in Figure V-3 represents abatement strategies that are available to the capped sectors in 2020, including offsets, renewable energy, vehicle efficiency, and biofuels. The baseline forecast for capped sectors is 408.8 $MMTCO_2e$ in 2020, so the capped sector must achieve reductions of at least 74.6 $MMTCO_2e$ in 2020 to achieve the AB 32 target.

Figure V-3: Total Capped Sector Abatement Potential in 2020



The total capped sector abatement curve shows approximately 108 $MMTCO_2e$ of abatement available in 2020, with over 32 $MMTCO_2e$ of that abatement having a negative cost per metric ton. The least expensive abatement opportunities are from the transportation sector. These include regional transportation targets (SB 375), biofuels, and high-efficiency vehicles.

Approximately 76 $MMTCO_2e$ of abatement potential is available at a positive cost-per-metric-ton. Offsets are available in the mid-range cost per metric ton ($10–$30/metric ton), with a total abatement potential of 30 $MMTCO_2e$. The residential and commercial sector has a wide range of abatement prices (-$10/metric ton to $100/metric ton). The power sector has the highest-priced abatement opportunities, with most greater than $80/metric ton.

b. Abatement Potential Driven by the Price Signal

The abatement potential driven by the price signal is shown in Figure V-4. This curve is a subset of the strategies plotted in the total capped sector abatement potential in Figure V-3. The abatement in Figure V-4 does not include reductions that are expected to take place due to complementary measures (e.g., LCFS, Advanced Clean Cars, RES, Regional Transportation Targets). The abatement potential driven by the price signal includes energy efficiency, even though energy efficiency is one of the complementary measures. It is included because

additional energy efficiency can be driven by the cap-and-trade program price signal. E3 assumes three energy-efficiency scenarios based on a 2007 CEC report[74] and ranging in cost from -$10 to $50/metric ton. High-cost energy efficiency becomes incentivized as energy prices increase due to price signal.

According to Figure V-4, approximately 72 $MMTCO_2e$ of abatement is available from capped sectors and offsets. Of this potential, 9 $MMTCO_2e$ of abatement has a negative cost-per-metric-ton. Most of the available abatement potential is from consumers. Even at a low costs, consumers respond with increased electricity efficiency. At higher costs, consumers respond with greater conservation of electricity and gasoline. A significant portion of offsets are available at medium prices ($10–$30/metric ton). Allowance price is shown to promote the creation of additional offsets, and increased allowance prices bring additional forestry, ODS, and methane digester offsets. At prices greater than $50/metric ton, it becomes cost-effective to dispatch power from natural gas power plants over coal power plants. Increasing the price further promotes additional dispatch switching to natural gas.

The abatement potential driven by the price signal is the primary tool used in the analyses of the compliance pathway scenarios. As mentioned, this curve only shows abatement strategies that are driven by a price signal, thus a given number of reductions can be used to determine the allowance price. With a given allowance price, staff can use the curve to analyze what strategies may or may not take place to describe the compliance pathways.

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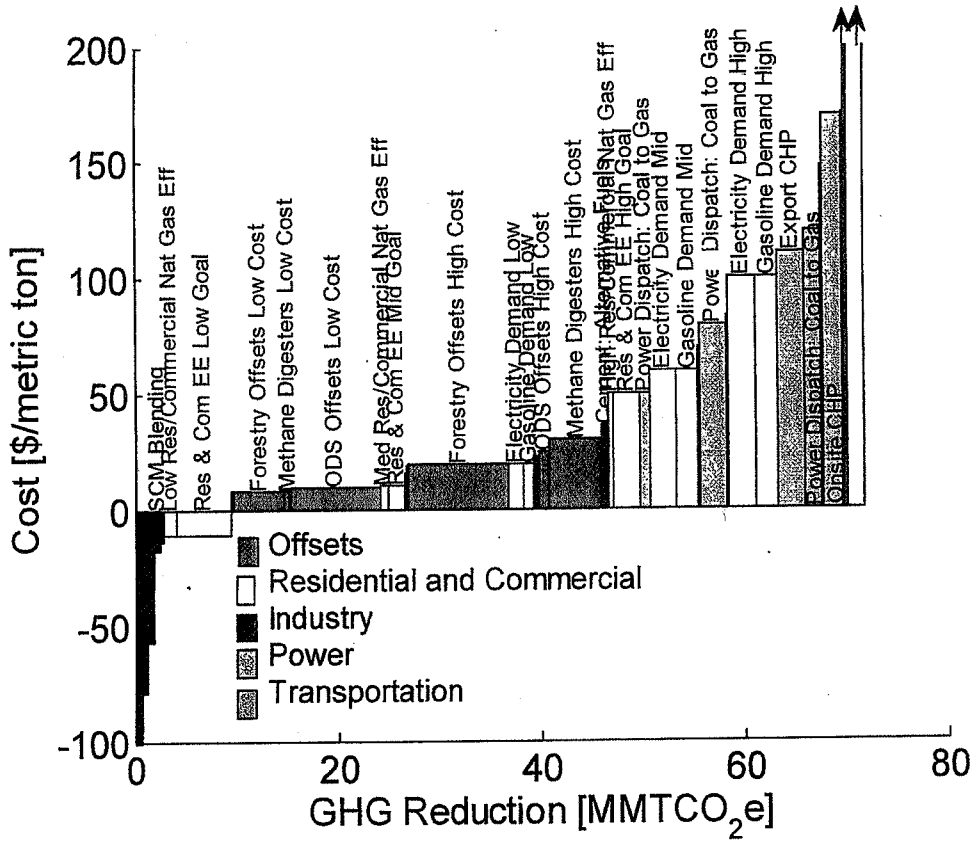
[74] Rufo, Michael W., and Alan S. North. *Assessment of Long-Term Electric Energy Efficiency Potential in California's Residential Sector.* California Energy Commission, PIER Energy-Related Environmental Research. CEC-500-2007-002.

Figure V-4: Abatement Potential Driven by the Price Signal in 2020



c. Industry-Only Abatement Reductions

Reductions from the industry section are shown in Figure V-5. A total of 5.5 $MMTCO_2e$ in reductions were identified for the industrial sector. The lowest cost reductions are boiler and process heater optimization. This is usually accomplished by trimming excess air in the units. Most optimization strategies have a significant negative cost, saving more than $100/metric ton; however, additional reductions can be attained at a cost of -$10/metric ton to $20/metric ton.

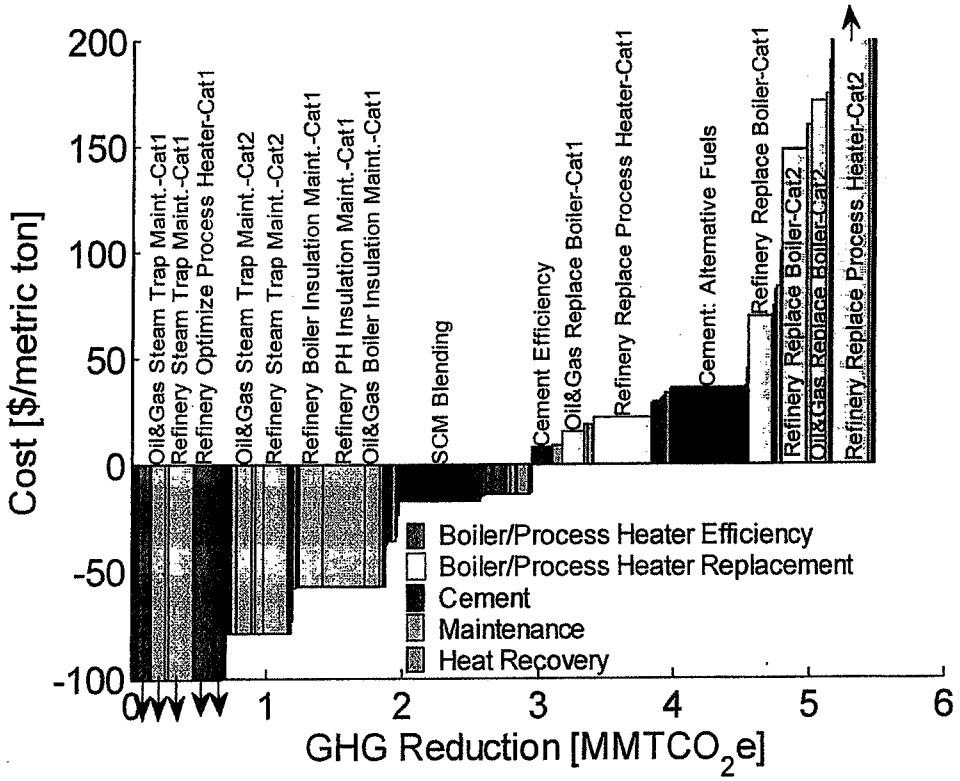
Maintenance strategies include steam leak and steam trap maintenance. Increasing maintenance has the largest potential to reduce GHG in the industrial sector. Most of these opportunities are available at negative costs, ranging from -$100/metric ton to -$40/metric ton. Additional maintenance for boilers and process heaters generates emissions reductions.

Staff looked at heat recovery techniques such as flue-gas heat recovery for process heaters, boiler economizers, and boiler blowdown heat recovery. This analysis found a small amount of abatement potential from heat recovery at a

negative cost. However, the cost of most abatement from heat recovery ranged between $10/metric ton and $100/metric ton.

Blending of semi-cementitious material (SCM) with cement to produce concrete has a large potential to reduce GHG emissions at a savings (-$17/metric ton). Semi-cementitious materials are a by-product of coal-fired power plants and other industrial facilities. Blending SCMs with cement results in more concrete per unit of cement, so that the emission intensity of the use of cement is decreased.

Figure V-5: Industry-Only Abatement Potential in 2020



An additional 2.58 $MMTCO_2e$ have a positive cost per metric ton, and thus, would likely not be implemented unless there was a price signal on GHG emissions. The largest abatement opportunities at positive costs per metric ton are boiler and process heater replacement. Depending on the efficiency of the unit being replaced, a range of costs vary between $20/metric ton and $200/metric ton. In the positive cost per metric ton, additional heat recovery strategies are also available. Alternative fuels for cement can achieve significant reductions at $36/metric ton.

F. Compliance Pathways Analysis

The proposed cap-and-trade program does not specify what combination of GHG abatement strategies regulated parties must implement. Instead, the program establishes an overall cap on GHG emissions and allows covered entities to use any combination of GHG abatement strategies, including those not covered in this Chapter, to achieve the cap. Based on the abatement strategies described above, ARB staff has analyzed four scenarios with different compliance pathways for achieving the necessary reductions.

The abatement strategies that sources will implement in the future cannot be predicted. Technologies that currently appear most likely to reduce emissions in the near- to mid-term could encounter delays, and development of other technologies could achieve breakthroughs. Also, since the proposed regulation is market based, regulated entities make decisions on energy efficiency using in-house analyses. Thus, the path taken to achieve the may be different from the pathways described below.

1. Results of Scenario 1: Full Abatement Potential from Complementary Policies, Full Availability of Offsets

In this scenario, full abatement potential is available from complementary policies and offsets. As discussed above, 74.6 $MMTCO_2e$ in reductions from projected baseline emissions are needed to meet the cap in 2020. Table V-3 identifies the reductions assumed in this scenario from complementary measures that will reduce emissions under the cap. The cap-and-trade program price signal is required to achieve the remaining reductions of 31.3 $MMTCO_2e$.

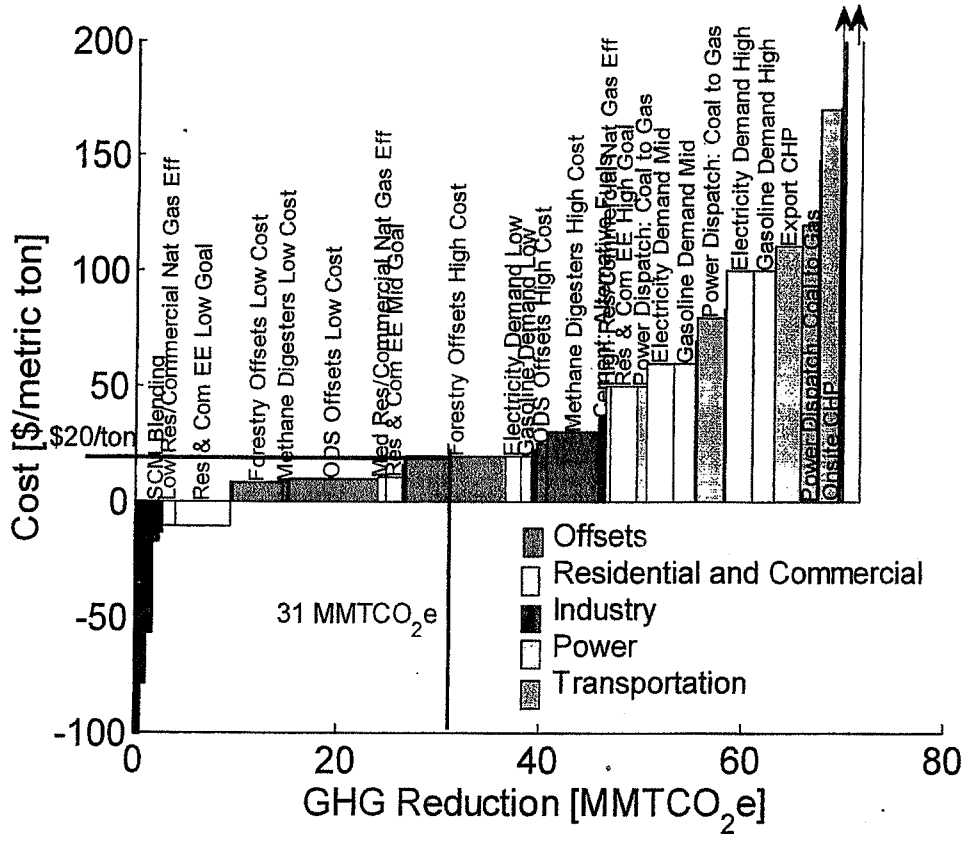
Table V-3: Scenario 1 Abatement Estimates (in $MMTCO_2e$) in 2020

Abatement Needed (Table V-1)	74.6
Advanced Clean Cars Standards	3.8
LCFS	15.1
Regional Targets	3.0
RES	11.4
Vehicle Efficiency	4.6
Goods Movement	3.5
Med-/Heavy-Duty Hybridization and Aerodynamics	0.9
High Speed Rail	1.0
Total Abatement from Complementary Policies	43.3
Abatement from Capped Sectors Driven by the Price Signal	31.3[75]

[75] Numbers may not add due to rounding.

The abatement curve driven by the price signal corresponding to Scenario 1 is shown in Figure V-6. As shown in the figure, 31 $MMTCO_2e$ of abatement corresponds to an allowance price of $20/metric ton. Thus, if all measures less than $20/metric ton are implemented, the emissions will stay below the cap. These measures include a number of low-cost industrial abatement strategies, such as optimization of boilers and process heaters, steam maintenance, and SCM blending. The residential and commercial sector will respond by implementing a large amount of residential and commercial efficiency. Approximately 16 $MMTCO_2e$ of offsets will be used to comply with the cap-and-trade regulation. All of the low-cost offsets will be used for compliance, and only a portion of the high-cost forestry projects will be implemented.

Figure V-6: Abatement Curve for Scenario 1 in 2020



2. Results of Scenario 2: Full Abatement Potential from Complementary Policies, Partial Availability of Offsets

In this scenario, the offsets potential is reduced by half. Table V-4 identifies the reductions assumed in the scenario from the complementary measures that will reduce emissions under the cap. Similar to Scenario 1, the complementary measures achieve 43.3 $MMTCO_2e$ of reductions, requiring the allowance price to drive an additional 31.3 $MMTCO_2e$ of reductions.

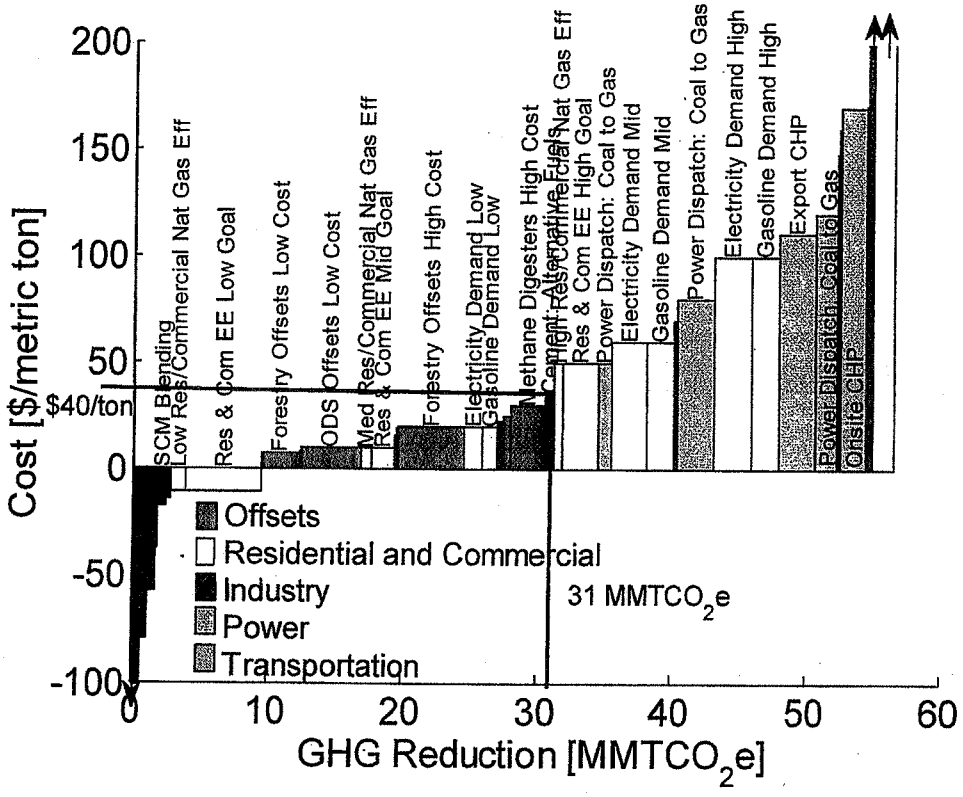
Table V-4: Scenario 2 Abatement Estimates (in $MMTCO_2e$) in 2020

Abatement Needed (Table V-1)	74.6
Advanced Clean Cars Standards	3.8
LCFS	15.1
Regional Targets	3.0
RES	11.4
Vehicle Efficiency	4.6
Goods Movement	3.5
Med-/Heavy-Duty Hybridization and Aerodynamics	0.9
High Speed Rail	1.0
Total Abatement from Complementary Policies	43.3
Abatement from Capped Sectors Driven by the Price Signal	31.3[76]

The abatement curve driven by the price signal corresponding to Scenario 2 is shown in Figure V-7. As shown in Figure V-7, 31 $MMTCO_2e$ of abatement corresponds to an allowance price of approximately $40/metric ton. Thus, all measures less than $40/metric ton are expected to be implemented. The increased price results from the limited offset potential in this scenario. In this scenario, all of the 15.1 $MMTCO_2e$ of available offsets potential are used to meet the cap, and there is an increased use of energy efficiency and demand-side reductions.

[76] Numbers may not add due to rounding.

Figure V-7: Abatement Curve for Scenario 2 in 2020



The results from this scenario show the importance of the offset program to mitigate prices. This curve can be compared to Scenario 1, which uses the same assumptions for the complementary measures but assumed ample offset supply. In comparing the curves, decreasing the offset potential by half increases the allowance price from $20/metric ton to $40/metric ton.

3. Results of Scenario 3: Partial Abatement Potential from Complementary Policies, Full Availability of Offsets

In this scenario, staff explores the complementary policies. Table V-5 identifies the reductions assumed in this scenario from complementary measures that will reduce emissions under the cap. Staff assumed 15 $MMTCO_2e$ less than the 43.3 $MMTCO_2e$ GHG reductions originally estimated from the complementary policies in Scenarios 1 and 2. In Scenario 3, 46.3 $MMTCO_2e$ of additional reductions are needed from the capped sectors based on the price signal.

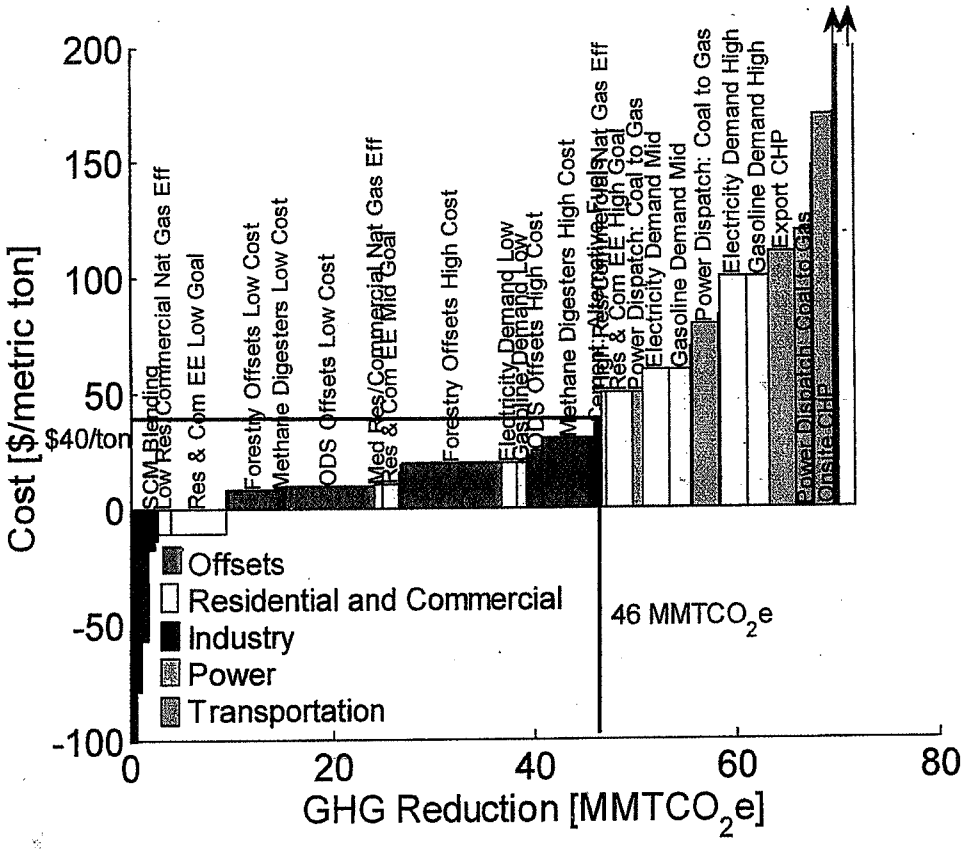
Table V-5: Scenario 3 Abatement Estimates (in $MMTCO_2e$) in 2020

Abatement Needed (**Table V-1**)	74.6
Abatement From Complementary Policies	28.3
Abatement from Capped Sectors Driven by the Price Signal	46.3[77]

The abatement curve driven by the price signal corresponding to Scenario 3 is shown in Figure V-8. As shown in the figure, 46 $MMTCO_2e$ of abatement corresponds to an allowance price of approximately $40/metric ton. Thus, all measures less than $40/metric ton are expected to be implemented. The medium-level allowance price spurs some demand-side changes from consumers and brings additional offsets online. In this curve, all of the approximately 30 $MMTCO_2e$ of available offsets were used to meet the cap. In the range of $10/metric ton to $30/metric ton, the curve has a low slope, meaning that the marginal allowance price is slowly increasing. Thus, from the price of $10 to $30/metric ton, capped sectors can increase abatement with relatively little price fluctuation.

[77] Numbers may not add due to rounding.

Figure V-8: Abatement Curve for Scenario 3 in 2020



4. Scenario 4: Partial Abatement from Complementary policies, Partial Availability of Offsets

In Scenario 4, staff explores a limited abatement potential from the complementary policies and limited availability of offsets. As shown in Table V-6, 46 $MMTCO_2e$ of allowance price-driven abatements are needed from capped sectors.

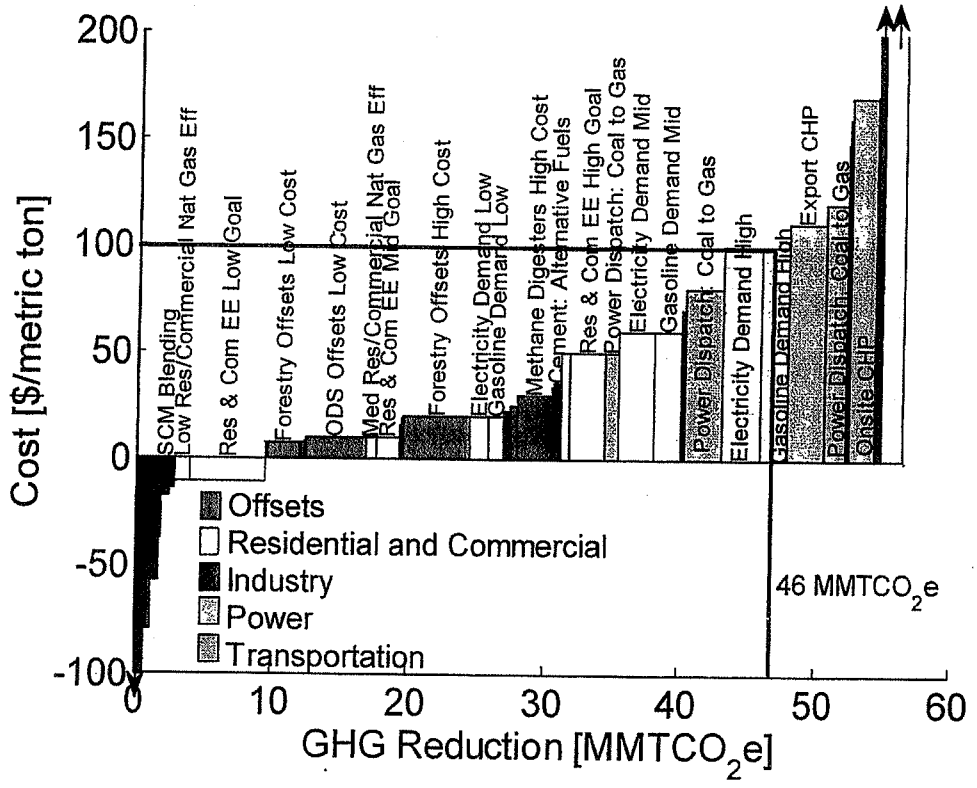
Table V-6: Scenario 4 Abatement Estimates (in $MMTCO_2e$) in 2020

Abatement Needed **(Table V-1)**	74.6
Abatement From Complementary Policies	28.3
Abatement from Capped Sectors Driven by the Price Signal	46.3[78]

[78] Numbers may not add due to rounding.

The abatement curve corresponding to Scenario 4 is shown in Figure V-9. As shown, 46 $MMTCO_2e$ of abatement corresponds to an allowance price of $100/metric ton. Thus, all measures less than $100/metric ton are expected to be implemented. To achieve the 46 $MMTCO_2e$ with limited offsets, high prices were necessary to achieve the abatement from the capped sectors. Many of the reductions were from consumers. A large amount of energy efficiency and demand-side reductions occurred to meet the necessary reductions. In addition, the significant power dispatch switching occurred. In this scenario, all of the 15 $MMTCO_2e$ of available offsets were used.

Figure V-9: Abatement Curve for Scenario 4 in 2020



The results from this scenario show the importance of complementary policies and offsets supply to obtaining the necessary GHG reductions to achieve the cap. The results of Scenario 2 (full complementary policies, partial offsets) and Scenario 3 (partial complementary policies, full offsets) show only modest price increases from Scenario 1 (full complementary policies, full offsets). However, in Scenario 4, large price increases occur due to the limited availability of reductions from complementary policies and offsets. This price increase is caused by requiring many of the reductions to come from consumers.

Even though the results of this scenario show an allowance price of $100/metric ton, achievement of this price is unlikely because of the cost containment

mechanism that makes allowances available at lower prices. For more information on cost containment, see Chapter II: General Summary of the Proposed Regulation.

5. Conclusion

The proposed cap-and-trade program provides a flexible market-based tool that can achieve the AB 32 goals under a number of different scenarios. Scenario 1, in which the complementary measures achieve expected reductions and there is a full supply of offsets, requires an allowance price of $20/metric ton to achieve the necessary reductions. Scenario 1 is considered to be the most likely scenario.

Scenario 2 shows the importance of offsets in mitigating high allowance price. In this case, the complementary measures reach their full potential but the offset potential is reduced by half, and the allowance price increases to $40/metric ton due to the reduced availability of offsets.

Scenario 3 shows the flexibility of the cap-and-trade program to meet the AB 32 goals. By reducing the abatement potential from the complementary measures, but assuming a full availability of offsets, this scenario illustrates that abatement can be met through additional purchase of offsets and additional consumer and industry responses. In Scenario 3, the allowance price is $40/metric ton.

Scenario 4 shows the worst case and least likely scenario, in which neither offsets nor complementary measures reach their full potential. In this case, allowance price increases to $100/metric ton, and the program relies on consumers and industry to make the necessary reductions. Nonetheless, demand response and a high level of energy efficiency can provide sufficient emissions reductions to meet the cap. It should be noted that it is highly unlikely that allowance prices will reach $100/metric ton because regulation includes a number of cost-containment mechanisms.

VI ENVIRONMENTAL IMPACTS OF THE PROPOSED REGULATION

This Chapter summarizes the environmental impacts analysis and identifies potential environmental benefits associated with the proposed cap-and-trade program. Complementing other AB 32 Scoping Plan measures, the proposed cap-and-trade program provides market-based incentives to reduce GHG emissions in California consistent with the requirements of AB 32, including HSC §38562, §38570, and §38571. The analysis shows that the proposed cap-and-trade program will reduce GHG emissions throughout the state. It will provide facility owners more flexibility to determine the most cost-effective way to meet emission reduction targets than a command-and-control approach with prescribed control measures would allow.

The California Environmental Quality Act (CEQA) and ARB policy require an analysis to determine the potential environmental impacts of the proposed regulation. ARB's program for adopting regulations has been designated as a Certified State Regulatory Program by the Secretary of Resources pursuant to Public Resources Code (PRC) section 21080.5. Consequently, the analysis required under CEQA may be included in the Initial Statement of Reasons (ISOR or Staff Report) rather than adhering to the format described in CEQA for an Initial Study, a Negative Declaration, or an Environmental Impact Report.

ARB has prepared a programmatic Functionally Equivalent Document (FED) that addresses direct and indirect impacts and identifies feasible mitigation that could be used to reduce significant adverse effects on the environment. This document is included in Appendix O, and is summarized in this Chapter. Staff's environmental analysis anticipates a variety of compliance responses that covered entities may use to comply with the program, such as increased energy efficiency, decarbonization of fuel, process changes, as well as surrender of allowances. These responses will not only help reduce GHG emissions, but are also anticipated to provide multiple environmental co-benefits that can provide relief from the demand on the State's already stressed water, air and mineral resources. A summary of the analysis of the potential environmental impacts and mitigation associated with covered entities' compliance responses follows. The Board is also considering approval of four offset protocols. Each of these protocols is analyzed individually. The FED also includes a cumulative impact section that examines impacts associated with the cap-and-trade program, in its entirety (including the protocols), and the remaining suite of Scoping Plan measures. Staff will respond to all significant environmental issues raised by the public during the 45-day public review period or at the Board hearing in the Final Statement of Reasons for the proposed regulation.

A. Summary of Environmental Analysis

1. Analyses of Emissions Reductions

The environmental analysis of the proposed cap-and-trade program focuses on the activities that those covered by the program could take to reduce GHG emissions. The purpose of the cap-and-trade program is to reduce GHG emissions from sources subject to the regulation (i.e., covered entities). This is achieved by applying an aggregate total GHG emissions cap on covered entities that declines over time. The program provides a trading mechanism for compliance instruments that offers covered entities flexibility in how they comply with the regulation. Reductions in GHG emissions would result from the use of cleaner fuels and from investment in onsite efficiency and process improvements. Additional reductions would come from offset projects that reduce emissions not directly covered by the cap-and-trade program or increase sequestration of carbon. Covered entities must turn in "allowances" and offset credits equal to their emissions. They may choose to lower their emissions to reduce their compliance obligation or procure allowances and/or offsets. The environmental analysis is based on the variety of covered entities' expected compliance responses and their respective impacts on the physical environment.

Total GHG emissions under baseline conditions in 2020 are estimated to be 507 $MMTCO_2e$. GHG emissions from the capped sectors are approximately 409 $MMTCO_2e$ of the baseline. Reductions needed to meet the cap of 334 $MMTCO_2e$ will come in part through complementary measures from the Scoping Plan. After reductions from those measures, the cap-and-trade regulation is estimated to reduce at least 18 $MMTCO_2e$, representing a 4 percent reduction from capped sector emissions. The reductions needed from cap-and-trade could be greater if adopted measures fail to achieve expected reductions, if energy efficiency programs are not funded at adequate levels or are less effective than projected, or if the economy grows faster than expected.

The cap-and-trade program is made up of many elements, must serve a large number of important objectives at the same time, and relies on the cumulative actions of a large number of participants operating in a complex market system. Accordingly, unanticipated effects and results could occur over the life of the program. ARB therefore is committed to using an adaptive management process to review and revise policies, protocols, and procedures as more information becomes available. This approach is discussed further in Appendix O.

2. Impacted Communities

ARB is committed to making the achievement of fair treatment of people of all races, cultures, and incomes with respect to the development, adoption, implementation and enforcement of environmental laws, regulations, and policies. This commitment is an integral part of development and implementation of the proposed cap-and-trade program. As such, staff evaluated the proposed regulation to determine if it disproportionately affects local communities, or

interferes with the attainment and maintenance of ambient air quality standards. As part of the Co-Pollutant Emissions Assessment of the cap-and-trade regulation, ARB staff evaluated the potential emissions impact of the regulation on four cumulatively impacted communities in California. The choice of communities captures the diverse nature of California's air quality problems, as well as a range of sources that would be subject to the regulation. The analysis found that the cap-and-trade program is unlikely to significantly impact on emissions in the four communities and is more likely to have a positive effect. The analysis is summarized in Chapter VII and Appendix P.

Also included in the environmental analysis is an examination of potential impacts to aesthetic resources, biological resources, cultural resources, energy demand, geological resources, land use, water quality and demand, among others. Possible approaches to mitigate or minimize these effects are included in the analysis.

B. Cap-and-Trade Program – Project Alternatives

Staff evaluated a suite of alternatives to the proposed regulation as required by the CEQA guidelines. A range of alternatives analyzed in an environmental document is governed by the "rule of reason," requiring evaluation of those alternatives "necessary to permit a reasoned choice." (CEQA Guidelines section 15126(f)). The alternatives include the required "No Project Alternative", as well as program design options, a regulation-only approach, a carbon fee, and others.

C. Statewide GHG Benefits from Cap-and-Trade

This section discusses staff's evaluation of the statewide GHG emission reduction estimates from the proposed cap-and-trade program.

GHG Emission Reduction Estimates

The amount of GHG emissions that would have to be reduced by the cap-and-trade program is a function of the 2020 business-as-usual (BAU) and the effectiveness of other Scoping Plan measures. Since adoption of the Scoping Plan, ARB has updated its emission inventories, revising the statewide 2020 emissions estimate to 507 $MMTCO_2e$. Scoping Plan measures that are adopted or would be adopted in the reasonably foreseeable future would achieve approximately 62 $MMTCO_2e$ of reductions. The cap-and-trade program must reduce at least 18 $MMTCO_2e$ to reach the 2020 target. The needed reductions could be greater if adopted measures fail to achieve expected reductions, if energy efficiency programs are not funded at adequate levels or are less effective than projected, or if the economy grows faster than expected. This is considered a beneficial impact.

D. Air Quality Impacts

This section discusses the potential air quality impacts related to the cap-and-trade program. Below are descriptions of the pollutants of interest in this chapter.

- Criteria Air Pollutants: Criteria air pollutants are determined to be hazardous to human health and are regulated under U.S. EPA's National Ambient Air Quality Standards. The 1970 amendments to the Clean Air Act require U.S. EPA to describe the health and welfare impacts of a pollutant as the "criteria" for inclusion in the regulatory regime. Both the California and federal governments have adopted health-based standards for the criteria pollutants that include ozone, particulate matter (10 microns or less in diameter, PM_{10} and 2.5 micron or less in diameter, $PM_{2.5}$), carbon monoxide (CO), nitrogen dioxide (NO_2), and sulfur dioxide (SO_2).

- Toxic Air Contaminants: Toxic air contaminants (TAC or toxics) are those pollutants which may cause or contribute to an increase in mortality or serious illness, or which may pose a hazard to human health even at very low concentrations.

ARB evaluated the potential statewide and localized emission impacts resulting from the changes in criteria pollutant and toxic air contaminant emissions that accompany implementing the proposed cap-and-trade program. The localized emission assessment is presented in Chapter VII and Appendix P: Co-Pollutant Emissions Assessment, and indicates that the proposed cap-and-trade program is expected to provide an emissions benefit by reducing emissions of criteria and toxic air pollutants. Because GHG emissions are largely the result of combustion, the declining cap will result in reduced combustion and related air pollution emissions. The estimated statewide emission reductions of criteria pollutants are shown in Table VI-1 below.

Table VII-1: Potential Statewide Reductions from the Proposed Cap-and-Trade Regulation in 2020*

(TPD)

ROG	CO	NO_x	$PM_{2.5}$
22.4	210.4	50.8	3.4

*Assumes implementation of adopted and foreseeable Scoping Plan measures in 2020 and that combustion emissions from capped sources decrease by 4 percent to meet the 2020 cap. The 4 percent reduction is estimated as follows. Total GHG emissions under baseline conditions in 2020 are estimated to be 507 $MMTCO_2e$. GHG emissions from the capped sectors are approximately 409 $MMTCO_2e$ of the baseline. Reductions needed to meet the cap of 334 $MMTCO_2e$ will come in part through complementary measures from the Scoping Plan. After reductions from those measures, the cap-and-trade regulation is estimated to reduce at least 18 $MMTCO_2e$, representing a 4 percent reduction from capped sector emissions.

An advantage of the cap-and-trade approach to achieving GHG emission reduction goals is that it gives facility owners more flexibility to determine the most cost-effective way to meet emission reduction targets than a command and control approach with prescribed control measures would allow. This flexibility to covered entities can help reduce the overall cost of meeting California's GHG emission reduction goals. This flexibility also means that there are no facility-specific emission reduction requirements for GHG emitting facilities. Because of this, some commenters have expressed concern that the cap-and-trade program could lead to disproportionate emission impacts. ARB's analysis, as detailed in the Co-Pollutant Emissions Assessment in Chapter VII and Appendix P: Co-Pollutant Emissions Assessment indicates that is unlikely. California's comprehensive control program will continue to reduce emissions and improve air quality. The cap-and-trade program is likely to provide small additional criteria pollutant reductions statewide. Although ARB's analysis indicates that localized impacts are unlikely, there is a chance that small increases that would be considered potentially significant under CEQA could occur. ARB proposes an adaptive management approach to address this potential impact.

Short-term increases in construction and operational emissions resulting from covered entity compliance responses are identified as significant and unavoidable in the FED, but could be evaluated by agencies with local permitting authority at the time specific projects are proposed and potentially mitigated to less than significant.

The proposed livestock offset protocol could result in a significant unavoidable impact resulting from the generation of odors that could affect sensitive receptors. Other than this potential odor impact, offset protocols would not be expected to result in potentially significant project-level impacts, or contribute to a cumulative, adverse air quality impact. New offset projects may be subject to local permitting processes and, if not exempt, environmental review under CEQA.

E. Other Environmental Impacts

1. Overview

The environmental analysis included in this Staff Report as Appendix O is a Functional Equivalent Document (FED), and complies with CEQA. It presents a programmatic evaluation that describes potential environmental impacts that are reasonably foreseeable, and does not speculate as to all of the possible compliance responses that could occur at the site- or project-specific levels. The compliance responses evaluated are representative of an entire business sector.

Although compliance with existing federal and state statutes and regulations, and local ordinances and permitting requirements may be adequate to address potential adverse project-specific environmental impacts, agencies with local permitting authority would be responsible for determining project-level impacts and mitigation. Because the programmatic analysis does not allow description of the details of project-specific mitigation, the degree of mitigation ultimately

implemented to reduce the potentially significant impacts is inherently uncertain. Consequently, the FED takes the conservative approach in its post-mitigation significance conclusions (i.e., tending to overstate the risk that feasible mitigation may not be sufficient or may not be implemented by other parties) and discloses, for CEQA compliance purposes, that potentially significant environmental impacts may be unavoidable. It is expected that many impacts resulting from covered entity compliance responses and offset projects would be avoided or mitigated to a less-than-significant level, and many potentially significant impacts would be addressed during project-specific environmental review processes.

2. Impact Analysis

This section evaluates potential impacts that could result from implementation of the covered entity compliance responses. The reasonably foreseeable covered entity compliance responses are some combination of (1) Upgrade Equipment, (2) Decarbonization, (3) Implement Process Changes, and (4) Surrender Compliance Instruments, and implementation of offset projects under the Compliance Offset Protocol for U.S. Ozone Depleting Substances Projects, Compliance Offset Protocol for Livestock Manure (Digesters) Projects, Compliance Offset Protocol for Urban Forest Projects, and the Compliance Offset Protocol for U.S. Forest Projects.

a. Aesthetics

Implementation of the cap-and-trade program would not result in actions that would pose a significant adverse impact to aesthetic, scenic, or visual resources.

The compliance responses implemented by covered entities largely consist of onsite improvements to existing facilities located in industrial settings, and as such would not change the character of the project sites.

The ODS offset protocol would not introduce activities that would disrupt aesthetic or visual settings. The Livestock offset protocol would include the construction of digesters in agricultural settings. Digesters are consistent with agricultural uses and would not represent an adverse change to the visual character of the vicinity. The Urban Forest offset protocol would improve the quality of the urban visual environment and would be considered aesthetically beneficial. The Forest offset protocol would not increase the amount of forest activities, but could shift activities to projects that increase carbon sequestration. This shift could change the visual character of offset project sites over time, but would not pose an adverse visual impact. Managing forests to increase cover and remove dead and diseased trees may be considered a visually beneficial effect.

b. Agriculture and Forest Resources

Implementation of the cap-and-trade program would not result in actions that would pose a significant adverse impact to agriculture and forest resources.

The compliance responses implemented by covered entities largely consist of onsite improvements to existing facilities located in industrial settings, and as such would not be expected to impact agriculture or forest resources.

The ODS offset protocol would not include activities that impact agriculture or forest resources. The Livestock offset protocol would include the construction of digesters in agricultural settings. Digesters are consistent with agricultural uses and would not represent an adverse change to agriculture or forest resources. The Urban Forest offset protocol would not impact agriculture or forest resources. The Forest offset protocol would not increase the amount of forest activities, but could shift activities to projects that increase carbon sequestration. Managing forests to increase cover and remove dead and diseased trees may be considered a beneficial impact to forests. The Forest offset protocol does not include actions that would encourage the conversion of agricultural land to forest.

c. Biological Resources

Implementation of the cap-and-trade program has the potential to adversely impact biological resources.

The compliance responses evaluated in the FED consist of onsite improvements to existing facilities located in industrial settings. Construction, grading and trenching have the potential to adversely impact any protected biological resources that might exist at those locations. Although recognized mitigation measures exist to reduce this potential impact, the authority to require mitigation lies with local permitting agencies and not ARB. Consequently, this potentially significant impact may be unavoidable.

The ODS offset protocol would not include activities that potentially impact biological resources. The Livestock offset protocol would include the construction of digesters at or adjacent to existing livestock operations where natural habitats are expected to be absent or limited. As such, the livestock offset protocol would result in less than significant impacts to biological resources. The Urban Forest offset protocol recognizes tree improvement projects in urban settings, and as such would not be expected to significantly affect biological resources. The Forest offset protocol would not increase total forest activities, but could shift activities to projects that increase carbon sequestration. This shift could change the habitat of offset project sites over time. Consequently, this potentially significant impact may be unavoidable. ARB will implement adaptive management to monitor this impact.

d. Cultural Resources

Implementation of the cap-and-trade program has the potential to adversely impact cultural resources.

The compliance responses evaluated in the FED consist of onsite improvements to existing facilities located in industrial settings. Construction, grading and

trenching have the potential to adversely impact any cultural resources that might exist at those locations. Although recognized mitigation measures exist to reduce this potential impact, the authority to require mitigation lies with local permitting agencies and not ARB. Consequently, this potentially significant impact may be unavoidable.

The ODS offset protocol would not include activities that potentially impact cultural resources. The Livestock offset protocol would include the construction of digesters at or adjacent to existing livestock operations where cultural or historic features could exist. Similarly, the Urban Forest offset protocol includes projects in urban settings where cultural and historic resources could exist. Although recognized mitigation measures exist to reduce these potential impacts, the authority to require mitigation lies with local permitting agencies and not ARB. Consequently, these potential impacts are identified as significant and unavoidable. The Forest offset protocol could change the type of forest projects that are undertaken, but would not alter the overall level of forest activities, and as such would not increase potential impacts to cultural resources. This potential impact would be less than significant.

e. Energy Demand

Implementation of the cap-and-trade program would reduce energy demand, representing a beneficial effect.

The covered entity compliance responses evaluated in the FED include upgrading equipment, switching to lower-intensity carbon fuels, and implementing maintenance and process changes. These actions will reduce overall energy demand and are considered beneficial effects.

Projects implemented under the compliance offset protocols will not increase energy demand, and as such pose no impact or less than significant impacts to energy demand.

f. Geology, Soils, and Mineral Resources

Implementation of the cap-and-trade program has the potential to adversely impact geology, soils, and mineral resources.

The covered entity compliance responses evaluated in the FED include onsite improvements to existing facilities located in industrial settings. Construction, grading and trenching have the potential to result in adverse soil erosion, dust generation, and sedimentation of local waterways. Although recognized mitigation measures exist to reduce this potential impact, the authority to require mitigation lies with local permitting agencies and not with ARB. Consequently, this potentially significant impact may be unavoidable.

The ODS offset protocol would have no impacts on geology, soils and mineral resources. The Livestock offset protocol would include the construction of digesters that would be subject to regulations that are considered sufficient to

mitigate potential impacts to geology, soils and mineral resources to a less than significant level. The Urban forest offset protocol would result in only minor soils disturbance and would not be expected to adversely impact geology, soils or mineral resources. This impact would be less than significant. The Forest offset protocol would not increase total forest activities, but could shift activities to projects that increase carbon sequestration. Because the overall level of forest activities would not change, this impact would be less than significant.

g. Hazardous Materials

Implementation of the cap-and-trade program would not result in actions that would result in potentially significant adverse impacts related to hazards or hazardous materials.

The covered entity compliance responses evaluated in the FED include onsite improvements to existing facilities located in industrial settings. The use of hazardous materials is common practice in industrial settings. Implementation of compliance responses could include the use of hazardous materials, but this would be considered simply an extension of business as usual for most covered entities, mitigated by existing practices and regulations, and thus considered less than significant.

Offset projects implemented under the proposed offset protocols may result in the use or transport of hazardous materials that require special handling and disposal. All projects would be required to comply with established local, state, and federal laws pertaining to the use, storage, and transportation of these materials. Assuming compliance with applicable laws and regulations, the impacts would be less than significant.

h. Hydrology and Water Quality

Implementation of the cap-and-trade program has the potential to adversely impact hydrology and water quality.

The covered entity compliance responses evaluated in the FED include onsite improvements to existing facilities located in industrial settings. Construction, grading and trenching have the potential to result in adverse soil erosion resulting in sedimentation and degradation of local waterways. Although recognized mitigation measures exist to reduce this potential impact, the authority to require mitigation lies with local permitting agencies and not with ARB. Consequently, this potentially significant impact may be unavoidable.

The ODS offset protocol would have no adverse impacts on hydrology and water quality. The Livestock offset protocol would include the construction of digesters that would be subject to regulations which are considered sufficient to mitigate potential impacts to hydrology and water quality to a less than significant level. The Urban forest offset protocol would result in only minor soil disturbance resulting in less than significant impacts to hydrology or water quality. The Forest offset protocol would not increase total forest activities, but could shift

activities to projects that increase carbon sequestration. Because the overall level of forest activities would not change, the potential to adversely impact hydrology and water quality would not change. This impact would be less than significant..

i. Land Use and Planning

Implementation of the cap-and-trade program has the potential to result in a significant adverse impact to land use and planning.

The covered entity compliance responses evaluated in the FED include onsite improvements to existing facilities located in industrial settings, and as such would be consistent with the existing land use and would pose a less than significant land use and planning impact.

The ODS offset protocol would use existing facilities, representing a less than significant impact to land use and planning. The Livestock offset protocol would allow the construction of digesters in agricultural settings. Digesters are a consistent use in agricultural areas. As such, their construction would not conflict with existing land use plans, and thus would be a less than significant impact.

Projects implemented under the Urban Forest offset protocol would not conflict with land use plans, resulting in a less than significant impact.

The Forest offset protocol includes avoided conversion projects that could conflict with local land use plans that envision development or other uses of forested areas. Consequently, this potentially significant impact may be an unavoidable conflict with local land use plans.

j. Noise

Implementation of the cap-and-trade program has the potential to result in a significant adverse noise impact.

The covered entity compliance responses evaluated in the FED include upgrading equipment, switching to lower intensity carbon fuels, and implementing maintenance and process changes. Construction has the potential to introduce short-term noise levels that would exceed acceptable ambient levels. Because of the short-term nature of construction, and the general compatibility of loud sounds with industrial settings, this impact would be less than significant. Recognized measures are standard business practice to minimize construction noise.

The ODS offset protocol would not result in significant adverse noise impacts. The Livestock offset protocol would allow the construction of digesters in agricultural settings. Construction of digesters could adversely impact sensitive receptors and is considered a significant and unavoidable impact. Although recognized mitigation measures exist to reduce this potential impact, the

authority to require mitigation lies with local permitting agencies and not ARB. Consequently, this potentially significant impact may be unavoidable.

Projects implemented under the Urban Forest offset protocol would not produce unacceptable noise levels and potential noise impacts are considered a less than significant impact.

Projects implemented under the Forest offset protocol would occur in forested areas. Forest projects would produce elevated noise levels that exceed accepted ambient levels. However, adoption of the Forest offset protocol would not alter the extent of forest activities, but would simply shift some activities to projects that sequester carbon. Because the level of overall forest activities would not change, the consequential noise impacts would not change. Thus, this impact is considered less than significant.

k. Population and Housing

The cap-and-trade program, including the proposed compliance offset protocols and associated offset projects would not be expected to result in significant adverse impacts to employment, population, or housing. All impacts to population, employment, and housing would be less than significant.

l. Public Services

The proposed covered entity compliance responses, compliance offset protocols and associated offset projects would not be expected to result in adverse impacts to public services. All potential impacts to public services would be less than significant.

The covered entity compliance responses evaluated in the FED include upgrading equipment, switching to lower-intensity carbon fuels, and implementing maintenance and process changes. These projects would not increase the level of public services beyond that already provided to existing facilities.

The ODS offset protocol, the Livestock offset protocol, and the Urban Forest offset protocol and associated projects would not result in a need for an increased level of public services beyond that already provided to existing facilities. The Forest offset protocol would not alter the extent of forest activities, but would shift some activities to projects that sequester carbon. Because the level of overall forest activities would not change, the consequential need for public services would not change. Thus, this impact would be less than significant.

m. Recreation

The proposed covered entity compliance responses, compliance offset protocols and associated offset projects would not be expected to result in adverse impacts to public services. All potential impacts to recreation would be less than significant.

The covered entity compliance responses evaluated in the FED include upgrading equipment, switching to lower intensity carbon fuels, and implementing maintenance and process changes. These actions would have a less than significant impact on recreation resources.

The ODS offset protocol, the Livestock offset protocol, and the Urban Forest offset protocol and associated projects would result in a less than significant impact on recreation resources.

Forest management activities could disrupt opportunities for forest recreation, but such disruptions exist under current conditions. Offset projects developed under the proposed Forest offset protocol would include the construction of roads, temporary closures for tree installation and periodic increases in truck or construction equipment traffic that could disrupt recreational activities, but forest projects developed under the Forest offset protocol would occur on land that was historically forested or currently forested, and consequently, the overall impact to recreational resources would be less than significant.

n. Transportation and Traffic

Implementation of covered entity compliance responses is not expected to cause significant adverse impacts to transportation or traffic. If a facility expands or requires construction to take place, increases in construction traffic would be temporary and considered less than significant. Construction traffic impacts can be mitigated through ingress and egress controls, traffic controls, and reduced speed zones to ensure safety. Activities undertaken to develop offset projects would be expected to vary according to the type of offset project. Construction of livestock digesters could require the operation of heavy equipment on rural roads, resulting in potentially significant safety concerns that may be unavoidable. Transportation and traffic impacts resulting from other offset protocol projects would be less than significant.

o. Utility Service Systems

The cap-and-trade program, including the proposed compliance offset protocols and associated offset projects would not significantly increase or decrease the need for utilities and associated services, and as such would be a less than significant impact.

The covered entity compliance responses evaluated in the FED include upgrading equipment, switching to lower-intensity carbon fuels, and implementing maintenance and process changes. These projects would not increase the level of utilities beyond that already provided to existing facilities. Fuel switching could require provision of new services. The availability and extension of utilities is subject to approval of the local utility provider, and thus mitigated to less than significant.

The ODS offset protocol, the Livestock offset protocol, and the Urban Forest offset protocol and associated projects would not result in a need for an

increased level of utilities beyond that already provided to existing facilities. Construction of new facilities would require the extension of utilities and services. The availability and extension of utilities is subject to approval of the local utility provider, and thus mitigated to less than significant.

The Forest offset protocol would not alter the extent of forest activities, but would shift some activities to projects that sequester carbon. Because the level of overall forest activities would not change, the consequential need for utility service systems associated with those activities would not change. Thus, this impact is considered less than significant.

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VII CO-POLLUTANT EMISSIONS ASSESSMENT

A. Introduction

AB 32 requires ARB, to the extent feasible, and in furtherance of achieving the statewide greenhouse gas (GHG) emissions limits, to: consider the potential for direct, indirect, and cumulative emissions impacts, including any localized impacts; prevent increases in criteria and toxic air pollutants; and maximize additional environmental and economic benefits. Although the cap-and-trade regulation is specifically aimed at reducing GHGs, technology improvements and enhanced energy efficiency can also reduce criteria and toxic air pollutants (co-pollutants) associated with GHG emissions as a co-benefit. Reductions in co-pollutants will have positive health benefits and assist in meeting health-based air quality standards. The AB 32 Scoping Plan estimated statewide co-pollutant reductions from the combination of measures in the Plan. This assessment focuses on the potential for direct, indirect, and cumulative emissions impacts of the proposed cap-and-trade regulation. It is designed to evaluate the potential co-pollutant benefits from the rule, scenarios which might lead to potential increases in co-pollutants, and cumulative emissions impacts on communities already adversely impacted by air pollution.

The assessment focuses on the potential criteria and toxic pollutant emissions impacts from the industrial and electricity generation sources covered by the program. The assessment does not include criteria pollutant and toxic emissions reductions that the cap-and-trade program is expected to provide from transportation fuels and commercial and residential gas use in addition to those likely to occur at industrial and electricity generation facilities.

Designing the emissions assessment proved to be challenging, given the nature and complexity of a cap-and-trade rule. The inherent flexibility provided by cap-and-trade makes it difficult to predict the specific changes that may result at an individual facility, and in turn, how those changes may impact cumulative emissions within a particular community. Because of the market-based design of the program, compliance decisions are expected to reflect the relative cost of compliance options. However, other business and operational considerations, such as overall economic growth and demand for their products, will also influence the choices made by regulated entities. For this reason, this assessment uses a case study approach to look at potential emissions impacts at a community level. Although staff's analysis indicates that emissions increases as a result of the cap-and-trade program are unlikely, the case studies are designed as a hypothetical bounding exercise to look at both the best-case and worst-case emissions scenarios, to characterize the bounds of potential outcomes and cumulative impacts.

Any evaluation of potential impacts must consider the existing programs that are already in place to address criteria and toxic air pollutants. California's air quality program leads the nation in terms of stringency of required emission controls.

This includes local air district permitting programs for stationary sources; ARB's comprehensive control programs for mobile sources, goods movement, and diesel risk reduction; and the air toxics identification and risk assessment process. The cap-and-trade regulation will not affect the stringency of these programs. Rather, sources regulated by the cap-and-trade program must continue to operate within these existing requirements and as such the cap-and-trade program provides an additional mechanism to ensure continued air quality improvement.

California's air pollution control programs for criteria and toxic pollutants will continue to significantly reduce emissions and health risk into the future. Reductions in co-pollutants that occur as a result of AB 32 complement the benefits of California's existing air quality programs. Reducing emissions from combustion sources is at the core of California's program to meet air quality standards for ozone and fine particles and is also central to the AB 32 Scoping Plan for meeting the 2020 greenhouse gas emissions target. California's climate and criteria pollutant programs are complementary, and the AB 32 regulations ARB is adopting will provide benefits that will be incorporated into future air quality plans for ozone and fine particles.

The potential for cumulative impacts in communities already adversely impacted by air pollution is included as a specific consideration in the statute, but AB 32 does not define "cumulative emissions impacts" or "communities already impacted by air pollution." Most urban areas in California are impacted by air pollution on a regional basis, and as a result, all have air quality programs and plans in place that are designed to provide for compliance with air quality standards. Transportation and industrial air pollution sources are also concentrated in urban areas, which can contribute to cumulative emissions impacts on a localized level. Rural areas downwind of urban centers also experience poor air quality due to the transport of air pollution, and are adversely impacted by air pollution. Each of these situations is considered in this assessment, to the extent feasible, with special attention to the potential for localized impacts in communities experiencing the greatest air pollution impacts.

The emissions assessment is designed to meet statutory requirements to evaluate the potential emissions impacts of the proposed cap-and-trade rule and complements the Health Impact Assessment (HIA) being conducted by the California Department of Public Health (CDPH). To supplement ARB's emissions assessment, the HIA evaluates potential health impacts other than air pollution effects and explores other issues such as health disparities among communities, and potential uses of revenue generated by the program to further improve public health in California. CDPH recently presented its work plan to the California Climate Action Team Public Health Work Group. Broader considerations related to community health status, air pollution exposures, and vulnerable populations are expected to be part of a public decision-making process on the use of revenues generated by the program. Taken together, the

ARB emissions assessment and the HIA provide information on the broad implementation of the cap-and-trade program.

This emissions assessment analyzes a range of potential compliance options for industrial and electricity generation sources in the cap-and-trade program. Most compliance approaches are expected to result in reductions in co-pollutants through increased efficiency and decreased combustion of fossil fuels. However, the regulation affords entities flexibility to choose the most cost-effective strategies to reduce emissions, so the potential for some compliance actions to result in increased co-pollutant emissions at some facilities cannot be entirely discounted. [79] For this reason, continued monitoring and review will be necessary to identify situations where increases in criteria pollutants and toxics might occur, and to allow the appropriate agencies to take the needed steps to address them. Many of the mechanisms are already in place to do so: stationary source control and permitting programs; toxics control and risk assessment requirements; and air monitoring for ozone, $PM_{2.5}$, and toxics.

Although staff believes that the potential for emissions increases attributable to the rule are very unlikely, ARB is committed to monitoring the implementation of the cap-and-trade regulation to identify and to address any situations where the program has caused an increase in criteria pollutant or toxic emissions. At least once each compliance period, ARB will use information collected through the mandatory reporting regulation, the cap-and-trade regulation, the industrial efficiency audit, and other sources of information to evaluate how individual facilities are complying with the regulation. The cap-and-trade program is another layer of review and opportunity for data gathering, decision-making, and agency and public vigilance to ensure any potential increases are identified and addressed.

B. Methods for Identifying Cumulatively Impacted Communities

In 2005, ARB sponsored a research project on an environmental justice screening method that combines indicators of current air pollution risk with social and health vulnerability. The final report for this work is entitled: *Air Pollution and Environmental Justice: Integrating Indicators of Cumulative Impact and Socio-*

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[79] Not all emissions increases at facilities covered by the cap-and-trade program will result from the program itself. The cap-and-trade program will place a new regulatory requirement and a new cost on GHG emissions from all covered facilities, so that the program provides an incentive to decrease (or to minimize increases in) GHG emissions and any related emissions of criteria or toxic emissions. While the program provides flexibility that could allow increased production due to economic growth, such increases would not be caused by the cap-and-trade program. Staff believes that only in very limited circumstances would a localized emissions increase be the actual result of the incentives created by the cap-and-trade program – e.g. shifting of production within a company from an inefficient facility with higher compliance costs to a more efficient facility that results in higher emissions at the more efficient facility.

Economic Vulnerability into Regulatory Decision-Making.[80] The final report was reviewed by the ARB Research Screening Committee.

This screening approach is a visual mapping tool and scoring procedure that examines cumulative impacts in neighborhoods. The screening approach incorporates a number of indicators of cumulative impact, reflecting research on air pollution, public health, and environmental justice. It incorporates indicators for three categories of potential impact and vulnerability: air pollution exposures and health risk, social and health vulnerability, and proximity between hazardous and sensitive land uses.

To identify communities for the case studies, ARB consulted with the Environmental Justice Advisory Committee (EJAC)[81] and other environmental stakeholders. These groups recommended that multiple communities be evaluated. Staff also considered availability of data, concentration of facilities that would be subject to cap-and-trade, and regional diversity. As a result, this assessment looks at four cumulatively impacted communities: Wilmington, Oildale/Bakersfield, Richmond, and Apple Valley/Oro Grande. Wilmington is identified as a cumulatively impacted community by the mapping tool described in *Air Pollution and Environmental Justice: Integrating Indicators of Cumulative Impact and Socio-Economic Vulnerability into Regulatory Decision-Making.* At this time, that mapping tool is available only for the Los Angeles region. ARB is in the process of evaluating how to expand the availability of this screening approach statewide. The other three communities are also identified as cumulatively impacted by a similar screening tool developed by ARB staff. While the ARB staff-developed tool does not include all the factors used in the research contract tool, if the latter were available statewide, it is expected that it would identify the same three communities as appropriate case studies.

In addition to requiring an assessment of the emissions impact, AB 32 requires the Board, where applicable and feasible, to direct investment toward the most disadvantaged communities. With respect to the cap-and-trade rule, this relates to the use of allowance value. This emissions assessment does not address the distribution of revenues, which is an implementation issue that deserves serious consideration and a broad-based public discussion. Identification of disadvantaged communities must be part of that discussion, including the

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[80] California Air Resources Board (2010): Air Pollution and Environmental Justice: Integrating Indicators of Cumulative Impact and Socio-Economic Vulnerability into Regulatory Decision-Making. http://www.arb.ca.gov/research/apr/past/04-308.pdf.

[81] Environmental Justice Advisory Committee (2008): Recommendations and Comments of the Environmental Justice Advisory Committee on the Implementation of the Global Warming Solutions Act. California Air Resources Board. http://www.arb.ca.gov/cc/ejac/proposedplan-ejaccommentsfinaldec10.pdf

possible use of the mapping tool described in *Air Pollution and Environmental Justice: Integrating Indicators of Cumulative Impact and Socio-Economic Vulnerability into Regulatory Decision-Making.*

C. Method for Assessing Cumulative Emissions Impact

This assessment addresses potential direct, indirect, and cumulative emissions impacts in the context of both emission and air pollution exposure trends. Some air pollutant emissions directly impact health, while others chemically react in the atmosphere to form pollutants of health concern. Ambient air monitoring data provide empirical information on recent trends in exposure to air pollution for both direct air pollutants and those formed in the atmosphere. The full assessment is described in Appendix P: Co-Pollutant Emissions Assessment.

Determining the potential impact of the cap-and-trade regulation on cumulative emissions requires looking at how various industrial sectors and individual facilities may move to comply with the program and then evaluating that response in the context of all emissions from all sources, first at the regional level, and then at the local level. This assessment takes a stepwise approach, with each step providing information used by ARB staff to conduct the subsequent analyses.

Step 1: The assessment considers California's existing regulatory programs governing smog-forming, fine particulate, and toxics emissions from stationary sources. Any specific changes made at a facility in response to the cap-and-trade regulation must be in compliance with this framework, which includes regulatory programs, permit systems, risk assessment, and more. Appendix P summarizes the major programs that will reduce emissions from cars, trucks, and other mobile sources between now and 2020. Appendix P also describes cumulative emissions today statewide, as well as recent air quality. Maps are presented that show how air quality varies within the State to provide context for the community case studies.

Step 2: The assessment examines future emissions in 2020. Appendix P describes the expected emissions reductions that will take place at the regional level as a result of the existing control programs and the contribution of the capped sources to the regional cumulative emissions totals in 2020. This shows that absent the cap-and-trade rule, capped industrial and electricity generation sources are forecast to be less than 10 percent of cumulative emissions from all sources. This percentage varies by region and pollutant.

Step 3: The assessment looks at the potential impact of the cap-and-trade regulation on co-pollutant emissions, starting with a general description of how the cap-and-trade industrial and electricity generation sectors may respond to rule requirements, how other greenhouse gas programs apply to the sectors, and how the existing co-pollutant control requirements examined in Step 1 overlay. This analysis appears in Appendix P: Co-Pollutant Emissions Assessment.

Step 4: The assessment examines four communities. Each community assessment includes descriptions of current air quality exposure and trends, existing co-pollutant emissions and control programs, and an evaluation of the potential for cumulative emissions impacts in 2020 from the implementation of the cap-and-trade program. The full assessments are presented in Appendix P: Co-Pollutant Emissions Assessment.

D. Community Case Studies

For major pollutants like ozone and $PM_{2.5}$, it is important to ensure that any actions taken through a cap-and-trade rule do not hinder progress toward attainment of air quality standards established to protect public health. With that as a framework, this section focuses on four communities and explores hypothetical situations that might result from the implementation of a cap-and-trade rule at a local level. A full description of the assessment appears in Appendix P: Co-Pollutant Emissions Assessment.

The choice of communities captures the diverse nature of California's air quality problems, as well as range of sources that would be subject to the cap-and-trade regulation. The boundary of each assessment area captures the most highly impacted communities. Because community level exposure reflects impacts from both local and regional emission sources, the size of each assessment area was selected to encompass a representative sampling of cap-and-trade sources which could potentially impact the local community. The size also represents a balance between reflecting broader regional-scale impacts versus smaller facility-specific impacts. The four communities are:

- Wilmington and Richmond: These two cities are part of larger metropolitan areas in Southern and Northern California. They are located among a nexus of major transportation corridors, large refineries and other industrial and electricity generation facilities, and busy international ports. The concentration of emission sources contribute to air quality problems in the local community, as well as downwind areas. Both Wilmington and Richmond have a large number of industrial and electricity generation facilities that would be subject to the cap-and-trade regulation.

- Bakersfield/Oildale: This region of the Central Valley has a mix of sources ranging from agricultural operations to widely dispersed stationary sources. The area also has a significant amount of mobile source emissions, resulting from its location along the two interstate highways connecting Northern and Southern California. The Bakersfield region has one of the most severe air quality problems in the nation. The Bakersfield/Oildale area contains a diverse array of industrial and electricity generation facilities that would be subject to the cap-and-trade regulation.

- Oro Grande: This community is located in the high Mojave Desert and includes the moderately sized towns of Hesperia and Victorville. Local air pollution sources are primarily from mineral extraction and related

commercial activities. This area has a small number of industrial and electrical generation sources that would be subject to the cap-and-trade regulation, with a focus on cement manufacturing. The local air quality problem is primarily due to the community's proximity to the South Coast, which transports substantial air pollution into the Mojave Desert.

As noted above, each community has a unique mix of industrial and electricity generation sources that would be subject to the cap-and-trade regulation. Air quality experienced by community residents is influenced by regional emissions and air quality levels, as well as an additional overlay from local sources. Therefore the assessment for each community begins with an overview of air quality and emissions on a regional basis, and then focuses on the nature of the local air quality problem and the local sources, including industrial and electricity generation facilities expected to be subject to the cap-and-trade regulation. It is difficult to predict how individual facilities within a given community may respond to the cap-and-trade regulation. However, staff examined hypothetical bounding scenarios in each community based on the nature of the sources in that community and the possible responses for each cap-and-trade sector, as discussed in Appendix P: Co-Pollutant Emissions Assessment.

1. Description of the Scenarios

Because of the compliance flexibility provided by the cap-and-trade regulation, it was not possible to identify facility-specific changes that might occur within each community. Instead, three basic hypothetical bounding scenarios were used to assess potential cumulative emissions impacts. Those bounding scenarios are: (1) a bounding co-benefit scenario, where all covered industrial and electricity generation facilities within the community reduce their greenhouse gas emissions, (2) a bounding dis-benefit scenario where all covered facilities increase their emissions, and (3) a second dis-benefit scenario where a new facility is built in the community.

For each assessment, the emissions reductions that will result from ongoing regulatory programs to reduce co-pollutants between 2008 and 2020 provide the baseline for evaluating each scenario's impacts. This baseline reflects what would occur in the absence of cap-and-trade, or if all GHG reductions were achieved outside the community.

The first scenario explores the potential co-benefits of limiting trading and the use of offsets within a community. The baseline (no change) and the first scenario bound the most likely impact of the regulation's implementation. In addition, staff examined the potential impacts of general facility growth through two additional scenarios. The possible co-pollutant increases in these two additional scenarios cannot be specifically attributed to the cap-and-trade regulation. The scenario analysis focused on the industrial and electricity generation facilities covered under cap-and-trade and does not address the additional reductions that will likely occur when transportation fuels and commercial and residential natural gas are also included under the cap.

ARB staff believes that scenarios 2 and 3 are very unlikely to result from the cap-and-trade regulation. Many factors influence a decision to expand production or build a new facility, and the cap-and-trade program itself imposes a new requirement on facilities—the need to procure allowances and offsets to accommodate GHG emissions—in addition to the strict permitting requirements already in effect for criteria pollutants and toxic air contaminants. Under scenario 2, every facility would need to purchase allowances and offsets to accommodate any growth. We believe it is more likely that a few facilities may increase production, while others would decrease. Similarly, we do not believe that compliance with the cap-and-trade regulation will cause the siting of new facilities assumed in scenario 3, though the regulation would not prevent it. Nevertheless, both scenarios are useful as hypothetical bounding analyses.

Scenario 1: The first scenario assumes as a hypothetical upper bound that GHG emissions reductions occur at each of the local industrial and electricity generation facilities in the community. On average, the cap-and-trade industrial and electricity generation sources will need to reduce their GHG emissions by 4 percent to meet the 2020 cap.[82] Therefore, staff assumed a commensurate 4 percent reduction would occur in combustion-related NOx, $PM_{2.5}$, and reactive organic gases (ROG) from these industrial and electricity generation facilities. These additional reductions would further enhance the cumulative emissions reductions from ongoing programs.

Scenario 2: The second scenario represents a hypothetical emissions increase of 4 percent at each of the cap-and-trade facilities in the community. While this scenario provides a hypothetical upper bound of aggregate facility growth in the community, staff believes it is an unlikely situation, given the current regulatory structure. As described in Appendix P: Co-Pollutant Emissions Assessment, each individual unit of permitted equipment has a maximum permitted emission limit. Large facilities such as those covered under cap-and-trade often have hundreds of individual permits. If the facility owner modified that equipment or its operation such that actual emissions would exceed the permitted levels, New Source Review (NSR) and its requirements to implement Best Available Control Technology (BACT) would apply. This is a comprehensive and lengthy process that is subject to public review. The extensive requirements of this permitting process effectively limit the potential for significant emissions increases at a given facility.

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[82] Total GHG emissions under baseline conditions in 2020 are estimated to be 507 $MMTCO_2e$. GHG emissions from the capped sectors are approximately 409 $MMTCO_2e$ of the baseline. Reductions needed to meet the cap of 334 $MMTCO_2e$ will come in part through complementary measures from the Scoping Plan. After reductions from those measures, the cap-and-trade regulation is estimated to reduce at least 18 $MMTCO_2e$, representing a 4 percent reduction from capped sector emissions.

In addition, under this scenario, every facility would need to purchase allowances and offsets to accommodate any growth. While there could be growth at a few facilities within a community, as some facilities move to more efficient ways of operation or switch to use of less carbon-intensive fuels, it is very unlikely that emissions would increase at every facility. Much more likely is a situation where a few facilities may increase production, while others would decrease. Nevertheless, staff evaluated the impact of an increase of 4 percent at every facility to represent a potential maximum community-level impact.

Scenario 3: For the third scenario, ARB assumed the hypothetical construction of a new facility within the community. For each community, ARB chose to site a facility consistent with the already existing industrial and electricity generation sources. Siting of a new facility would generally trigger NSR and its requirements to implement BACT would apply. This is a comprehensive and lengthy process that is subject to public review. In addition, the new facility would need to purchase allowances and offsets to accommodate its GHG emissions. As discussed above, ARB staff believes that the cap-and-trade regulation is unlikely to trigger construction of new facilities.

There is also the potential for increases in toxic air contaminants under Scenarios 2 and 3. Toxics emissions are typically reflected in $PM_{2.5}$ and ROG emission estimates, thus efforts to control ROG and $PM_{2.5}$ also help address toxic air contaminants broadly within the community. In addition, the requirements of the "Hot Spots"[83] Information and Assessment Act are designed to assess and mitigate more localized, facility-specific impacts. As described earlier in this section, should emissions of toxics increase such that they exceed the screening threshold, the facility would be required to conduct a Health Risk Assessment. Facility emissions that are determined to present a significant risk would then be required to implement measures to reduce that risk.

2. Limitations

These scenarios focus on the compliance responses of the industrial and electricity generation sources covered by the cap-and-trade regulation. In 2015, transportation fuels and commercial and residential natural gas will be included in the cap, likely reducing emissions from those sources. Because the reductions associated with transportation fuel and commercial and residential natural gas would be the same for each of the scenarios, ARB chose to focus the analysis on industrial and electricity generation sources. The inclusion of the emissions reductions from transportation fuel and commercial and residential natural gas

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[83] California Air Resources Board: Webpage (as reviewed January 14, 2010): AB 2588 Air Toxics "Hot Spots" Program. http://www.arb.ca.gov/ab2588/ ab2588.htm.

would likely increase the total co-pollutant benefits of the cap-and-trade regulation.

In all scenarios it is difficult to predict the actual air quality impacts within the local community of any change in emissions. For example, combustion emissions, especially from large industry and electricity generation sources, are often vented through tall stacks. The heat generated by the combustion process can further increase the height of the emissions plume. As a result, emissions from a large stack may not reach the surface until some distance downwind. In addition, due to dispersion and the time needed for chemical reactions to form regional pollutants such as ozone and secondary particulate matter, the maximum air quality impact may occur well downwind of a facility.

Air quality modeling is a standard tool for relating emissions to estimated air quality impacts. However, detailed information is required by the models to quantify the impacts. This information includes specificity on locations and types of emission sources, stack heights, timing of emissions, emission rates, and for point sources, information to characterize the point of release. Due to the flexibility each individual facility has to comply with the cap-and-trade regulation, it is impossible to characterize the timing and location of emissions changes. This makes use of modeling to characterize the air quality impact of potential changes in emissions infeasible.

Health assessments of the impact of air quality changes on human health require estimates of the change in $PM_{2.5}$, ozone, and other air pollutants for an exposed population. The health impact depends on the air pollutant type and ambient concentration, location and duration of exposure, and characteristics of the exposed population, including total number of residents, age, and baseline incident rates for various death and disease types where a quantitative relationship has been established with an air pollutant. Health assessments in California have been limited to pollution sources where $PM_{2.5}$, ozone, and air toxic exposures can be estimated using measured air quality data as a surrogate for a widely distributed source (e.g., trucks) or with the use of air quality models (e.g., ports and railyards). However, there is no unique air quality surrogate for the large industrial and electricity generation sources covered by the cap-and-trade regulation to distinguish them from smaller industrial and electricity generation sources or other types of combustion sources. Nor, as discussed above, was it feasible to conduct air quality modeling. Due to this lack of information on the concentration, location, and duration of air pollutant exposures, it was not possible to conduct a health assessment.

3. Wilmington Assessment

Wilmington is a suburb of Los Angeles, with a racially and ethnically diverse population of about 53,000 (See map in Appendix P: Co-Pollutant Emissions Assessment). Located between the Port of Los Angeles and the Port of Long Beach, the Wilmington area includes a diverse range of stationary and mobile source emissions. In combination, these two ports represent the third

largest container port in the world and account for about 25 percent of California's goods movement emissions[84]. These shipping activities result in large amounts of diesel and fugitive emissions from bulk transport operations. In addition to port-related activities, Wilmington and the surrounding area are home to railyards, major transportation corridors, oil refineries, and power plants, as well as other industrial and commercial operations. Approximately 300,000 people live within the emissions assessment area.

A total of 15 industrial and electricity generation facilities in the Wilmington area would be subject to the cap-and-trade regulation. See Appendix P: Co-Pollutant Emissions Assessment for a description of air quality and emissions in the Wilmington area and the traditional emissions control programs currently in place. Appendix P: Co-Pollutant Emissions Assessment also includes a discussion of potential emissions changes that could occur under the cap-and-trade regulation.

As described above, ARB developed three hypothetical bounding scenarios to assess potential cumulative emissions impacts in 2020 in Wilmington. For the third scenario (placing a new facility in the community), ARB evaluated the hypothetical construction of a new combined heat and power facility within the community. A combined heat and power generation facility was selected because petroleum refining is the largest cap-and-trade emissions sector in the Wilmington area. This would have the dual benefit of providing a more efficient heat source for refinery processes, while allowing excess power to be sold back to the grid. Table VII-1 provides an estimate of criteria pollutant emissions from a hypothetical 85 megawatt (MW) combined heat and power unit. It is important to remember that under California's existing regulatory structure, the construction of a new facility would be subject to the strict NSR permitting requirements described in Appendix P: Co-Pollutant Emissions Assessment. This would include requirements to implement BACT, as well as to offset the emissions regionally.

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[84] California Air Resources Board (2006): Proposed Emission Reduction Plan for Ports and Goods Movement in California.
http://www.arb.ca.gov/planning/gmerp/march21plan/march22_plan.pdf

Table VII-1
Estimated Criteria Pollutant Emissions
Hypothetical Combined Heat and Power Facility
(85 MW Capacity)

	Emissions (tons per day)		
	NOX	ROG	PM2.5
Operating Emissions	0.11	0.05	0.12

Analysis of Potential Impacts

Under the baseline existing control program, including rules adopted in the 2007 State Implementation Plan (SIP)[85] to meet national air quality standards, the Wilmington area will realize further NOx, $PM_{2.5}$, and ROG emissions reductions in 2020. The reductions will come primarily from mobile sources, including light- and heavy-duty vehicles and from port-related activities such as ships maneuvering and anchoring within the port area and equipment used to load and unload ships. As shown in Table VII-2, these ongoing emissions reductions result in a 23 percent reduction in NOx, a 24 percent reduction in $PM_{2.5}$, and a 4 percent reduction in ROG emissions from 2008 levels.

The first scenario assumes that all the emission reductions needed from the cap-and-trade regulation are implemented locally at the 15 industrial and electricity generation facilities in the Wilmington area, realizing a further 4 percent reduction in combustion-related co-pollutant emissions. Because emissions from the cap-and-trade industrial and electricity generation facilities comprise only a small portion of the overall inventory, these reductions translate into less than a 4 percent decrease in the total inventory for the Wilmington area. In aggregate, implementation of reductions for the cap-and-trade regulation by industrial and electricity generation sources locally would result in an additional 1 percent enhancement in localized NOx and $PM_{2.5}$ reductions, and a small enhancement of less than 1 percent in ROG reductions. While not quantified here, combustion-generated toxic air contaminants would also likely decrease.

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[85] California Air Resources Board: Webpage (as reviewed February 9, 2010): Proposed State Strategy for California's State Implementation Plan (SIP) for the New Federal PM2.5 and 8-Hour Ozone Standards. http://www.arb.ca.gov/ planning/sip/2007sip/2007sip.htm

Table VII-2
Percent of Emissions Reductions Between 2008 and 2020
Wilmington Area[1]

	NO_x	$PM_{2.5}$	ROG
BASELINE Emission Reductions from Existing Controls and No Emission Reductions at Cap-and-Trade Industrial and Electricity Generation Facilities	**23%**	**24%**	**4%**
SCENARIO 1 Emission Reductions from Existing Controls and Emission Reductions at all Cap-and-Trade Industrial and Electricity Generation Facilities	**24%**	**25%**	**4%**
SCENARIO 2 Emission Reductions from Existing Controls and Emission Increases at all Cap-and-Trade Industrial and Electricity Generation Facilities	**22%**	**22%**	**3%**
SCENARIO 3 Emission Reductions from Existing Controls and Addition of New Facility	**23%**	**20%**	**4%**

Numbers are rounded to nearest percentage

[1] These tables include the combined emissions from mobile, area, and stationary sources. The industrial and electricity generation facilities covered by the proposed cap-and-trade regulation represent only a portion of these emissions. The emission impacts of the scenarios do not include the additional emissions reductions that will likely occur when transportation fuels and commercial and residential natural gas are included in the cap. The emissions reductions from transportation fuels and commercial and residential natural gas would affect each of these scenarios equally.

As described previously, while ARB staff did not find situations where emissions increases were clearly attributable to implementation of cap-and-trade, the second scenario evaluated the potential general impact of an emissions increase of 4 percent at every cap-and-trade industrial and electricity generation facility in the community region. This hypothetical upper-bound increase in emissions would slightly reduce the benefits of the ongoing control program, with a 2 percent reduction in $PM_{2.5}$ benefits, and a 1 percent reduction in NOx and ROG benefits. However, cumulative emissions in the Wilmington area would still be lower in 2020, as compared to 2008.

Scenario 3 explored the potential emissions impacts of construction of a new combined heat and power unit at an existing refinery. Based on typical emissions from similar units, the addition of a hypothetical new unit in the community would slightly reduce the benefits of the ongoing control program, with a 4 percent reduction in $PM_{2.5}$ benefits, and a very small reduction that is less than 1 percent in NOx and ROG benefits. Overall, cumulative emissions in the Wilmington area would still be lower in 2020, as compared to 2008.

Summary

In summary, air quality is improving throughout the Wilmington area. The assessment area meets both the federal annual $PM_{2.5}$ and 8-hour ozone standards, and the area is very close to meeting the daily $PM_{2.5}$ standard. California's ongoing co-pollutant emissions control programs will ensure that cumulative emissions will continue to decrease through 2020 in the Wilmington area, with associated health improvements from improved air quality.

While the cap-and-trade regulation allows for flexibility in how facilities comply, staff looked at several scenarios that bound the possibilities, including the construction of a new facility. If emissions reductions due to implementation of the cap-and-trade regulation occur locally at the fifteen facilities in Wilmington, there could be some small additional co-benefits from the reduction of combustion-related criteria pollutants. While emissions increases directly attributable to the cap-and-trade regulation are considered very unlikely, potential emissions increases that might occur in general are also expected to be small within the context of the larger cumulative emissions reductions that will be occurring as a result of California's extensive emissions control programs.

4. Oildale-Bakersfield Assessment

The Oildale/Bakersfield area (Bakersfield area) is located in the central portion of Kern County in the San Joaquin Valley Air Basin. It includes not only Oildale, but much of the Bakersfield urban area and the town of Shafter as well (See map in Appendix P: Co-Pollutant Emissions Assessment). Overall, about 425,000 people live in this area. In addition to significant mobile source emissions from trucks and passenger cars traveling along Highway 99 and Interstate 5, the Bakersfield area is adjacent to a number of oil fields, including two of the largest in California. The Kern River Oil Field to the east and northeast of Oildale has more than 9,000 active wells. It ranks second only to the Midway-Sunset Oil Field in southwestern Kern County. Other sizeable fields in the Bakersfield area include the Kern Front and Poso Creek oil fields north of Oildale and the smaller Fruitvale Oil Field to the southwest. In addition to the oil-related activities, the Bakersfield assessment area also contains a number of cogeneration facilities.

A total of 23 industrial and electricity generation facilities in the Bakersfield area would be subject to the cap-and-trade regulation. These facilities represent a mix of different types of operations. Appendix P: Co-Pollutant Emissions Assessment describes air quality and emissions in the assessment area and the traditional emissions control programs currently in place. This section provides a discussion of the emissions changes that could occur under the cap-and-trade regulation.

As described above, ARB developed three hypothetical bounding scenarios to assess potential cumulative emissions impacts in 2020 in the Bakersfield area. For the third scenario (placing a new facility in the community), ARB evaluated the hypothetical construction of a new biorefinery within the Bakersfield area.

The Low Carbon Fuel Standard and the federal renewable fuels standard have mandated that biofuels become a greater portion of transportation fuels, in order to reduce GHG emissions. Agricultural activities in the San Joaquin Valley generate materials that could be used to fuel a biorefinery. Table VII-3, below, provides an estimate of criteria pollutant emissions from a hypothetical biofuel refinery with an annual capacity of 50 million gallons. Under California's existing regulatory structure, the construction of a new facility would be subject to the strict NSR permitting requirements described in Appendix P. This would include requirements to implement BACT, as well as to offset the emissions regionally. There is also the potential for increased truck traffic to deliver biomass to the plant. However, due to ARB regulations, in 2020 most trucks will be required to be equipped with the cleanest 2010 engines, as well as diesel particulate traps.

Table VII-3
Estimated Criteria Pollutant Emissions
Hypothetical Biofuel Refining Facility
(50 million gallons/year capacity)

	Emissions (tons per day)		
	NO_X	ROG	PM_{10}
Cellulosic Ethanol Facility	0.26	0.69	0.27

Analysis of Potential Impacts

Under the existing baseline control program, including rules adopted in the 2007 SIP to meet national air quality standards, the Bakersfield area would realize NOx, $PM_{2.5}$, and ROG emissions reductions in 2020. The reductions will come primarily from on-road and off-road motor vehicles. As shown in Table VII-4, these ongoing emissions reductions result in a 44 percent reduction in NOx and an 11 percent reduction in both $PM_{2.5}$ and ROG emissions from 2008 levels.

The first scenario assumes that all the emissions reductions needed from the cap-and-trade regulation are implemented locally at the 23 industrial and electricity generation facilities in the Bakersfield area, realizing a further 4 percent reduction in co-pollutant emissions. Because emissions from the cap-and-trade industrial and electricity generation facilities comprise only a small portion of the overall inventory, these reductions translate into less than a 4 percent decrease in the total inventory for the Bakersfield area. In aggregate, full implementation of the cap-and-trade regulation by industrial and electricity generation sources locally would result in an additional 1 percent enhancement in localized NOx reductions, and a small, less than 1 percent enhancement in localized $PM_{2.5}$ and ROG reductions. While not quantified here, combustion-generated toxic air contaminants would also likely decrease.

Table VII-4
Percent Emissions Reductions Between 2008 and 2020
Bakersfield Area[1]

	NO_X	$PM_{2.5}$	ROG
BASELINE Emission Reductions from Existing Controls and No Emission Reductions from Cap-and-Trade Industrial and Electricity Generation Facilities	**44%**	**11%**	**11%**
SCENARIO 1 Emission Reductions from Existing Controls and Emission Reductions at all Cap-and-Trade Industrial and Electricity Generation Facilities	**45%**	**11%**	**11%**
SCENARIO 2 Emissions Reductions from Existing Controls and Emission Increases at all Cap-and-Trade Industrial and Electricity Generation Facilities	**44%**	**10%**	**11%**
SCENARIO 3 Emissions Reductions from Existing Controls and Addition of New Facility	**44%**	**7%**	**9%**

Numbers are rounded to nearest percentage

[1] These tables include the combined emissions from mobile, area, and stationary sources. The industrial and electricity generation facilities covered by the proposed cap-and-trade regulation represent only a portion of these emissions. The emissions impacts of the scenarios do not include the additional emissions reductions that will likely occur when transportation fuels and commercial and residential natural gas are included in the cap. The emissions reductions from transportation fuels and commercial and residential natural gas would affect each of these scenarios equally.

As described previously, while ARB staff did not find situations where emissions increases were clearly attributable to implementation of cap-and-trade, the second scenario evaluated the potential general impact of an emissions increase of 4 percent at every cap-and-trade facility in the assessment area. This hypothetical upper-bound increase in emissions would slightly reduce the overall benefits of the ongoing control program, with a 1 percent reduction in $PM_{2.5}$ benefits, and a very small reduction that is less than 1 percent in NOx and ROG benefits. However, cumulative emissions in the Bakersfield area would still be lower in 2020, as compared with 2008.

Scenario 3 explored the potential emissions impacts of constructing a new biofuel refining facility. Based on typical emissions from similar facilities, the addition of a hypothetical new facility in the Bakersfield area would slightly reduce the benefits of the ongoing control program, with a 4 percent reduction in $PM_{2.5}$ benefits, 2 percent reduction in ROG benefits, and a small reduction that is less than 1 percent in NOx benefits. However, overall, cumulative emissions in the Bakersfield area would still be lower in 2020, when compared with 2008.

Summary

In summary, air quality is improving throughout the Bakersfield area, and the assessment area is making progress toward meeting the federal $PM_{2.5}$ and 8-hour ozone standards. California's ongoing co-pollutant emissions control programs will ensure that cumulative emissions will continue to decrease through 2020 in the Bakersfield area, with associated health improvements from improved air quality.

While the cap-and-trade regulation allows for flexibility in how facilities comply, staff looked at several scenarios that bound the possibilities, including the construction of a new facility. If emissions reductions due to implementing the cap-and-trade regulation occur locally at the 23 facilities in the assessment area, there could be some small additional co-benefits from the reduction of combustion-related criteria pollutants. While emissions increases directly attributable to the cap-and-trade regulation are considered very unlikely, potential emissions increases that might occur in general are also expected to be small within the context of the larger cumulative emissions reductions that will be occurring as a result of California's extensive emissions control programs.

5. Richmond Assessment

The Richmond area, located on both the San Pablo and San Francisco Bays, encompasses portions of Contra Costa, Alameda, and Solano Counties, and includes portions of the cities of Richmond, El Cerrito, Berkeley, Emeryville, Benicia, and Alameda (See map in Appendix P: Co-Pollutant Emissions Assessment). The area is home to a racially and ethnically diverse population of over approximately 500,000 people and contains a wide range of stationary and mobile source emissions. These sources include the Port of Richmond and the Richmond Rail Yard, which produce diesel and fugitive emissions from bulk transport operations. In addition, the Richmond area is home to oil refineries, power plants, and major transportation corridors, as well as other industrial and commercial operations.

A total of seven industrial and electricity generation facilities in the Richmond area would be subject to a cap-and-trade program. Appendix P: Co-Pollutant Emissions Assessment describes air quality and emissions in the Richmond area and the traditional emissions control programs currently in place. This section provides a discussion of potential emissions changes that could occur under the cap-and-trade regulation.

As described above, ARB developed three hypothetical bounding scenarios to assess potential cumulative emissions impacts in 2020 in the Richmond area. For the third scenario (placing a new facility in the community), ARB evaluated the hypothetical construction of a new combined heat and power facility within the community. A combined heat and power generation facility was selected because petroleum refining is the largest cap-and-trade emissions sector in the Richmond area. This would have the dual benefit of providing a more efficient

heat source for refinery processes, while allowing excess power to be sold back to the grid. Table VII-5, below, provides an estimate of criteria pollutant emissions from a hypothetical 85 megawatt (MW) combined heat and power unit. It is important to remember that under California's existing regulatory structure, the construction of a new facility would be subject to the strict NSR permitting requirements described in Appendix P: Co-Pollutant Emissions Assessment. This would include requirements to implement BACT, as well as to offset the emissions regionally.

Table VII-5
Estimated Criteria Pollutant Emissions
Hypothetical Combined Heat and Power Facility
(85 MW Capacity)

	Emissions (tons per day)		
	NO_X	ROG	$PM_{2.5}$
Operating Emissions	0.11	0.05	0.12

Analysis of Impacts

Under the existing baseline control program, including rules adopted in the 2007 SIP to meet national air quality standards, the Richmond area will realize further NOx and ROG emissions reductions in 2020. The reductions will come primarily from on-road motor vehicle and off-road mobile sources, including light- and heavy-duty vehicles. These ongoing emissions reductions are summarized in Table VII-6, and reflect a 25 percent reduction in NOx and ROG emissions from 2008 levels. In contrast, the Richmond study area would see a slight increase of 1 percent in $PM_{2.5}$ (reflected as negative numbers in Table VII-6), resulting from projected increases in area source emissions such as commercial cooking and residential fuel use, which are linked to population growth.

The first scenario assumes that all the emissions reductions needed from the cap-and-trade regulation are implemented locally at the seven industrial and electricity generation facilities in the Richmond area, realizing a further 4 percent reduction in co-pollutant emissions. Because emissions from the cap-and-trade industrial and electricity generation facilities comprise only a small portion of the overall inventory, these reductions translate into less than a 4 percent decrease in the total inventory for the Richmond area. In aggregate, full implementation of the cap-and-trade regulation by industrial and electricity generation sources locally would result in an additional 2 percent enhancement in localized NOx reductions, a 1 percent reduction in $PM_{2.5}$, and a small enhancement, less than 1 percent, in localized ROG reductions. While not quantified here, combustion-generated toxic air contaminants would also likely decrease.

Table VII-6
Percent of Emissions Reductions Between 2008 and 2020
Richmond Area[1]

	NOx	$PM_{2.5}$	ROG
BASELINE Emission Reductions from Existing Controls and No Emission Reductions at Cap-and-Trade Industrial and Electricity Generation Facilities	**28%**	**-1%**	**16%**
SCENARIO 1 Emissions Reductions from Existing Controls and Emission Reductions at all Cap-and-Trade Industrial and Electricity Generation Facilities	**30%**	**0%**	**16%**
SCENARIO 2 Emission Reductions from Existing Controls and Emission Increases at all Cap-and-Trade Industrial and Electricity Generation Facilities	**27%**	**-2%**	**14%**
SCENARIO 3 Emission Reductions from Existing Controls and Addition of New Facility	**28%**	**-2%**	**16%**

Numbers are rounded to nearest percentage

[1] These tables include the combined emissions from mobile, area, and stationary sources. The industrial and electricity generation facilities covered by the proposed cap-and-trade regulation represent only a portion of these emissions. The emissions impacts of the scenarios do not include the additional emissions reductions that will likely occur when transportation fuels and commercial and residential natural gas are included in the cap. The emissions reductions from transportation fuels and commercial and residential natural gas would affect each of these scenarios equally.

As described previously, while ARB staff did not find situations where emissions increases were clearly attributable to implementation of cap-and-trade, the second scenario evaluated the potential general impact of an emissions increase of four percent at every cap-and-trade facility in the community region. This hypothetical upper-bound increase in emissions would slightly reduce the overall benefits of the ongoing control program, with a 2 percent reduction in ROG benefits, a 1 percent reduction in NOx benefits, and an additional 1 percent increase in $PM_{2.5}$. However, cumulative emissions of NOx and ROG in the Richmond area would still be lower in 2020, as compared to 2008.

Scenario 3 explored the potential emissions impacts of construction of a new combined heat and power unit at an existing refinery. Based on typical emissions from similar units, the addition of a hypothetical new unit in the community would slightly reduce the benefits of the ongoing control program, with a very small reduction that is less than 1 percent in NOx and ROG benefits,

and an additional 1 percent increase in $PM_{2.5}$ emissions. Overall, cumulative emissions for NOx and ROG in the Richmond area would still be lower in 2020, as compared to 2008.

Summary

In summary, air quality is improving throughout the Richmond area. The assessment area meets both federal $PM_{2.5}$ and 8-hour ozone standards. California's ongoing co-pollutant emissions control programs will ensure that cumulative emissions will continue to decrease through 2020 in the Richmond area, with associated health improvements from improved air quality.

While the cap-and-trade regulation allows for flexibility in how facilities comply, staff looked at several scenarios that bound the possibilities, including the construction of a new facility. If emissions reductions due to implementation of the cap-and-trade regulation occur locally at the seven facilities in Richmond, there could be some small additional co-benefits from the reduction of combustion-related criteria pollutants. While emissions increases directly attributable to the cap-and-trade regulation are considered very unlikely, potential emissions increases that might occur in general are also expected to be small within the context of the larger cumulative emissions reductions that will be occurring as a result of California's extensive emissions control programs.

6. Apple Valley/Oro Grande Assessment

The Apple Valley/Oro Grande area (hereafter called the Oro Grande area) is an economically and racially diverse area located in the Mojave Desert's Victor Valley. With the town of Oro Grande in the northwest, Apple Valley in the center, and Lucerne Valley in the southeast of the assessment area, this high desert region also includes the towns of Victorville, Hesperia, and Adelanto. About 230,000 people live in this portion of the Mojave Desert (See map in Appendix P: Co-Pollutant Emissions Assessment).

Although the Oro Grande area is more sparsely populated than the South Coast region to the south, the desert communities have grown over the last several decades as bedroom communities of the South Coast. Interstate 15 and Highway 395 act as thoroughfares, carrying significant amounts of commuter and truck traffic in and out of the Mojave Desert region.

Four industrial and electricity generation facilities in the Oro Grande area would be subject to the cap-and-trade regulation. Appendix P describes air quality and emissions in the Oro Grande area and the traditional emissions-control programs currently in place. This section provides a discussion of potential emissions changes that could occur under the cap-and-trade regulation.

As described above, ARB developed three hypothetical bounding scenarios to assess potential cumulative emissions impacts in 2020 in Oro Grande. For the third scenario (placing a new facility in the community), ARB evaluated the

hypothetical construction of a new natural gas power plant. Due to requirements of the Renewable Energy Standard and other initiatives, there may be an increase in natural gas-fueled power generation, as compared to more carbon-intensive coal, in order to reduce GHG emissions. Given that the Oro Grande area already contains one small power facility, ARB staff evaluated the potential emissions from an additional natural gas facility. Table VII-7, below, provides an estimate of criteria pollutant emissions from a hypothetical 500 megawatt (MW) combined-cycle natural gas power plant. It is important to remember that under California's existing regulatory structure, the construction of a new facility would be subject to the strict NSR permitting requirement described in Appendix P: Co-Pollutant Emissions Assessment. This would include requirements to implement BACT, as well as offset the emissions regionally.

Table VII-7
Estimated Criteria Pollutant Emissions
Hypothetical Combined-Cycle Natural Gas Baseload Power Plant
(500 MW Capacity)

	Emissions (tons per day)		
	NO_X	ROG	PM_{10}
Operating Emissions	0.31	0.11	0.27

Analysis of Potential Impacts

Under the existing baseline control program, including rules adopted in the 2007 SIP to meet national air quality standards, the Oro Grande area would still realize NOx, $PM_{2.5}$, and ROG emissions reductions in 2020. The reductions will come primarily from on-road and off-road motor vehicles. As shown in Table VII-8, these ongoing emissions reductions result in a 16 percent reduction in NOx, 2 percent reduction in $PM_{2.5}$, and 3 percent reduction in ROG emissions from 2008 levels.

The first scenario assumes that all the emissions reductions needed from the cap-and-trade regulation are implemented locally at the four industrial and electricity generation facilities in the Oro Grande area, realizing a further 4 percent reduction in co-pollutant emissions. Because emissions from the cap-and-trade industrial and electricity generation facilities comprise only a small portion of the overall inventory, these reductions translate into less than a 4 percent decrease in the total inventory for the Oro Grande area. In aggregate, full implementation of the cap-and-trade regulation by industrial and electricity generation sources locally would result in an additional 3 percent enhancement in localized NOx benefits, and an additional 1 percent enhancement in both the $PM_{2.5}$ and ROG benefits (Table VII-8). While not quantified here, combustion-generated toxic air contaminants would also likely decrease.

Table VII-8
Percent Emissions Reductions Between 2008 and 2020
Oro Grande Area[1]

	NOx	$PM_{2.5}$	ROG
BASELINE Emission Reductions from Existing Controls and No Emission Reductions at Cap-and-Trade Industrial and Electricity Generation Facilities	**16%**	**2%**	**3%**
SCENARIO 1 Emissions Reductions from Existing Controls and Emission Reduction at all Cap-and-Trade Industrial and Electricity Generation Facilities	**19%**	**3%**	**4%**
SCENARIO 2 Emission Reductions from Existing Controls and Emission Increases at all Cap-and-Trade Industrial and Electricity Generation Facilities	**14%**	**0%**	**3%**
SCENARIO 3 Emissions Reductions from Existing Controls and Addition of New Facility	**16%**	**-1%**	**3%**

Numbers are rounded to nearest percentage

[1] These tables include the combined emissions from mobile, area, and stationary sources. The industrial and electricity generation facilities covered by the proposed cap-and-trade regulation represent only a portion of these emissions. The emissions impacts of the scenarios do not include the additional emissions reductions that will likely occur when transportation fuels and commercial and residential natural gas are included in the cap. The emissions reductions from transportation fuels and commercial and residential natural gas would affect each of these scenarios equally.

As described previously, while ARB staff did not find situations where emissions increases were clearly attributable to implementation of cap-and-trade, the second scenario evaluated the potential general impact of an emissions increase of 4 percent at every cap-and-trade facility in the community region. This hypothetical upper-bound increase in emissions would slightly reduce the overall benefits of the ongoing control program, with a 2 percent reduction in both NOx and $PM_{2.5}$ benefits, and a small reduction, less than 1 percent, in ROG benefits. However, cumulative emissions in the Oro Grande area would still be lower in 2020, as compared to 2008, for both NOx and ROG, while $PM_{2.5}$ emissions would remain constant.

Scenario 3 explored the potential emissions impacts of constructing a new natural gas power plant in the local area. Based on typical emissions from similar facilities, the addition of a hypothetical new facility would slightly reduce the overall benefits of the ongoing control program, with a small reduction, less

than 1 percent, in NOx and ROG benefits and a 1 percent increase in $PM_{2.5}$. Overall, cumulative emissions in the Oro Grande area would still be lower in 2020, as compared to 2008, for both NOx and ROG, while $PM_{2.5}$ emissions would increase slightly.

Summary

In summary, air quality is improving throughout the Oro Grande area. The assessment area meets the federal $PM_{2.5}$ standards and shows continued progress toward meeting the federal ozone standard. California's ongoing co-pollutant emissions control programs will ensure that cumulative emissions will continue to decrease through 2020 in the Oro Grande area, with associated health improvements from improved air quality.

While the cap-and-trade regulation allows for flexibility in how facilities comply, staff looked at several scenarios that bound the possibilities, including the construction of a new facility. If emissions reductions due to implementing the cap-and-trade regulation occur locally at the four facilities in the assessment area, there could be some small additional co-benefits from the reduction of combustion-related criteria pollutants. While emissions increases directly attributable to the cap-and-trade regulation are considered very unlikely, potential emissions increases that might occur in general are also expected to be small within the context of the larger cumulative emissions reductions that will be occurring as a result of California's extensive emissions control programs.

E. Conclusion

Due to California's comprehensive control programs, air quality has improved significantly throughout the State, with commensurate reductions in adverse health impacts. These improvements will continue through 2020 as ARB continues to adopt and implement regulations to meet State and federal air quality standards, reduce toxic risk, and decrease California's GHG emissions.

ARB's analysis demonstrated that California's existing programs to meet federal air quality standards will provide the majority of emissions reductions in each community, with further NOx reductions ranging from approximately 15 to 45 percent by 2020. Staff's analysis further indicates that the cap-and-trade regulation is expected to have a beneficial impact on emissions. In the communities evaluated, the regulation has the potential to provide small additional NOx reductions in the range of 1 to 3 percent if all GHG reductions were implemented locally. The assessment does not include criteria pollutant and toxic emissions reductions that the cap-and-trade program is expected to provide from transportation fuels and commercial and residential gas use, in addition to those likely to occur at industrial and electricity generation facilities.

Due to the inherent flexibility of the cap-and-trade regulation, as well as the overlay of other complementary GHG reduction measures, it is difficult to predict the decisions that individual facilities may make in any given community.

However, based on the available data, current law and policies that control industrial and electricity generation sources of air pollution, and expected compliance responses, ARB believes that emissions increases at the statewide, regional, or local level due to the regulation are not likely. The cap-and-trade program will provide an incentive for covered facilities to decrease GHG emissions and any related emissions of criteria and toxic pollutants.

VIII ECONOMIC IMPACTS OF THE PROPOSED REGULATION

A. Summary of Economic Impacts

The cap-and-trade program will lead to increased investment in efficient buildings and technologies and in advanced fuels. At expected allowance prices, these investments reduce fuel use by 2 to 4 percent in 2020, while economic growth between 2007 and 2020 continues at a rate virtually on par with current projections. Impacts on long-term projected growth rates in personal income and employment are similarly small. Implementation of the program will, however, shift investment and growth within the overall economy toward those sectors driven by the production of cleaner and more efficient technologies.

Implementing the cap-and-trade program can also help mitigate the economic consequences of continued reliance on fossil fuels. Experience in recent decades, such as the spike in world oil prices in the summer of 2008, has illustrated the economic costs of volatile energy prices on California's economy. While this report does not attempt to quantify the benefits of reduced dependence on fossil fuels in the face of continued volatility of world energy prices, it does show that California can significantly reduce its dependence on these fuels and, therefore, its vulnerability to future price spikes.

The cap-and-trade program is designed to help drive investment into activities that result in lower GHG emissions. As businesses and consumers make investments in energy efficiency and clean fuels, some sectors will see significant new activity, including those that design or manufacture renewable technologies, and those that provide energy retrofits or efficiency improvements. Because the models used in this analysis are based on the structure of the economy in the base year, the analysis does not fully reflect the potential for increased growth in output and employment in sectors that could benefit from this new investment. This analysis should be viewed as a conservative estimate of the potential statewide impacts from the program.

This economic analysis focuses exclusively on the economic effects in California of implementing the cap-and-trade program, and does not consider the avoided costs of inaction. The potential effects of climate change on California could cause severe economic damage. While California has developed a climate adaptation strategy to help alleviate these potential costs, the risk of potentially high economic costs from climate change in California remains real.[86]

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[86] *2009 California Climate Adaptation Strategy.* 2009. California Natural Resources Agency. Found at: http://www.climatechange.ca.gov/adaptation/.

While California acting alone cannot reduce emissions sufficiently to change the course of climate change worldwide, California's leadership has played, and continues to play, a critical role in moving federal and international climate policy forward. Successful implementation of AB 32, including the cap-and-trade program, has the potential to help move climate policy in a positive direction at the state, regional, and federal levels in the coming years. The magnitude of the impacts that California could face from climate change provide a useful context for understanding the significance of the relatively modest economic costs associated with taking action to reduce California's GHG emissions. Overall, staff finds no significant adverse impacts on California business or consumers as a whole as a result of the proposed regulation.

B. Legal Requirements

Section 11346.3 of the Government Code requires State agencies to assess the potential for adverse economic impacts on California business enterprises and individuals when proposing to adopt or amend any administrative regulation. The assessment must include a consideration of the impact of the proposed regulation on California jobs, the expansion, elimination or creation of businesses, and the ability of California businesses to compete with businesses in other states.

Also, State agencies are required to estimate the cost or savings to any State or local agency and school district in accordance with instructions adopted by the Department of Finance (DOF). The estimate shall include any non-discretionary cost or savings to local agencies and the cost or savings in federal funding to the State.

Finally, Health and Safety Code section 57005 requires the ARB to perform an economic impact analysis of submitted alternatives to a proposed regulation before adopting any major regulation. A *major regulation* is defined as a regulation that will have a potential cost to California business enterprises in an amount exceeding $10 million in any single year.

This Chapter provides a description of the methodology used to estimate costs, as well as ARB staff's analysis of the economic impacts on California businesses and State and local agencies.

C. Cap-and-Trade Program Design

The main design elements of the cap-and-trade program are described in Table VIII-1. The analysis is performed with the assumption that no regional or federal

climate program is in place prior to 2020.[87] Furthermore, the analysis does not speculate about polices that may be adopted to reach targets beyond the 2020 goal established by AB 32.

The modeling uses allowance prices that rise by a fixed percentage each year. Banking of allowances for future use is allowed without limitation. In the early years, relatively low-cost abatement opportunities are available. Thus, banking motivates emitters to over-comply in early years if those low-cost reductions can be credited against compliance obligations in later years.

Table VIII-1: Cap-and-Trade Program Elements

1.	Region	California
2.	GHG Pollutants	CO_2, CH_4, N_2O, SF_6, PFC, NF_3 and HFC
3.	Covered Sectors 2012–2014 2015–2020	 Electricity and large industrial Electricity, large industrial, transportation fuels, commercial and residential fuels, and small industrial
4.	Cap Trajectory	Linear phase-in
5.	Allocation	100 percent auction for the electricity sector
6.	Offsets	Limited to 8 percent of emissions
7.	Banking	Allowed without limitation
8.	Allowance Reserve	Allowances from the Reserve made available at $40, $45, and $50/metric ton in 2012, rising to $60, $67, and $75/metric ton in 2020

D. Costs and Benefits

The cap-and-trade program does not specify how or where emissions reductions will be made. Reductions will be made by covered sources if the cost of making reductions is less than the cost of acquiring allowances and offsets. Reductions will also be made throughout the economy as a result of increased investment in energy efficiency and energy conservation.

[87] The regulation allows linking with other programs, including those being developed by other WCI jurisdictions. However, a decision to link will require a separate regulatory action subject to the formal rulemaking process, including requirements for an economic analysis.

Compliance options available to California producers and consumers are discussed in Appendix F: Compliance Pathway Analysis. In this economic analysis, energy and economic models are used to generate estimates of the potential compliance costs and the associated economic impacts.

The financial effects of the cap-and-trade program can be divided into four main categories:

- Transaction costs (for covered sectors only).
- Changes in device and/or process expenditures.[88]
- Changes in fuel expenditures.
- Changes in device operation and maintenance expenditures.

In addition to analyzing these financial effects, this analysis also examines the macro-economic effects on California's economy.

Reductions in fuel use brought on by cap-and-trade will also reduce criteria pollutant emissions, as discussed in Chapter VII: Co-Pollutant Emissions Assessment and in Appendix P: Co-Pollutant Emissions Assessment. This analysis does not attempt to measure the economic benefits from reductions in criteria pollutants.

1. Transactions Costs

Transaction costs apply only to facilities with a compliance obligation. These costs can be grouped into three categories: (1) early implementation costs; (2) monitoring, reporting, and verification costs; and (3) trading costs.

Early implementation costs are fixed costs that are incurred only once, before the program launch; for example, the familiarization with program rules and guidelines, calculating baseline emissions, and the purchase of any necessary capital equipment. Annualized across the life span of the program, these costs would be significantly lower than the other transaction cost components for most of the program's participants.

The costs for monitoring, reporting, and verification of emissions are considered a part of the ARB Mandatory Reporting Rule and are not considered as additional in this analysis. However, staff notes that over time, the costs for

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[88] *Devices* are mechanical end-uses of energy, such as lighting, space heating, or air conditioning, while *process* reflects building shell improvements, such as insulation, or industrial process improvements.

monitoring, reporting, and verification of emissions should decline as a result of learning-by-doing and increased competition among verifiers. For example, a survey of Irish firms in the EU ETS found that for one quarter of the respondents, monitoring, reporting, and verification costs had decreased over the first three years of the EU ETS.[89] Based on analysis of existing programs, trading costs are not expected to be significant. Therefore trading costs will not be considered further in this analysis.

2. Expenditure Changes

The cap-and-trade program will affect the cost of using fossil fuel-based energy, which in turn will affect the price of most goods and services throughout the California economy. Some covered entities will make efficiency improvements that will reduce their emissions and their fuel expenditures. Additionally, increases in energy costs will drive secondary emissions reductions by non-covered entities though increased energy efficiency, decreased purchases of energy-intensive goods and services, and conservation.

Since the cap-and-trade program does not specify how or where emissions reductions will occur, it is impossible to know what covered or non-covered entities will do in response to the cap-and-trade program. Possible compliance responses must therefore be estimated using models. The Energy 2020 model was used to estimate the change in emissions and energy prices, and in capital, process, operation and maintenance, and fuel expenditures associated with a price on CO_2.

Energy 2020 is a detailed energy supply and demand and emissions accounting system of the Western United States. The model simulates the demand for all fuels for three residential categories, over 40 commercial and industrial categories, and three transportation categories. Additional detail on the Energy 2020 model is presented in Appendix N: Supporting Documentation for the Economic Analysis and the Energy 2020 Inputs and Assumptions book.[90]

Methods available for emissions reductions in Energy 2020 include:

- Fuel switching.[91]
- Earlier replacement of devices.

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[89] Jaraite, J., F. Convery, and C. Di Maria. 2009. *Transaction Costs of Firms in the EU ETS.* University College Dublin, School of Geography, Planning and Environmental Policy, Richview, Clonskeagh, Dublin.

[90] The Energy 2020 Inputs and Assumptions book can be found at: http://www.arb.ca.gov/cc/scopingplan/economics-sp/models/book1002.pdf.

[91] Renewable electricity above the 33 percent Renewable Electricity Standard or transportation biofuel penetration above the Low Carbon Fuel Standard is not assumed to occur in the Energy 2020 modeling.

- Purchase of devices with greater efficiency.
- Building shell improvements.
- Reductions in high-GWP gases.

Methods not available for emissions reductions in Energy 2020 include:[92]

- Carbon capture and sequestration.
- New nuclear power plants.

3. Economic Impacts

The overall impacts on the State economy are estimated using the Environmental Dynamic Revenue Assessment Model (E-DRAM). E-DRAM is a computable general equilibrium (CGE) model of the California economy. Computable general equilibrium models are standard tools of empirical analysis designed to assess the regional costs of GHG emissions limits that take into account all secondary effects that these policies could have on prices, commodity and factor substitutions, and incomes.

The E-DRAM model was developed by Dr. Peter Berck of the University of California, Berkeley, in collaboration with the California Department of Finance and the Air Resources Board. The current model includes 188 distinct sectors: 120 industrial sectors, 2 factor sectors (labor and capital), 8 household sectors, 9 consumption sectors, 1 investment sector, 45 government sectors, and 1 sector that represents the rest of the world.

More detail on the E-DRAM model is presented in Appendix N: Supporting Documentation for the Economic Analysis.

E. Economic Analysis

This analysis presents estimated impacts for a range of possible allowance prices. A large number of factors influence the allowance price.[93] The technological and behavioral factors include the ease of substitution by firms to low-GHG methods of production, the extent to which consumers shift to low-GHG products in response to changes in prices, and the pace of technological progress. A number of policy factors also apply. These include the stringency of

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[92] These technologies are unlikely to be available for emissions reductions before 2020. They may play a role in a longer-run emissions-reduction strategy.

[93] For a fuller discussion of these factors, see *Allocating Emissions Allowances Under a California Cap-and-Trade Program,* a report from the Economic and Allocation Advisory Committee. March 2010. http://www.climatechange.ca.gov/eaac/documents/eaac_reports/2010-03-22_EAAC_Allocation_Report_Final.pdf.

the overall cap and the reductions from other AB 32 policies. Other important policy factors include the extent of output-based updated free allocation, linkages with other markets, the availability and price of offsets, provisions for allowance banking and borrowing, and leakage.

Given the uncertainties about the nature of these factors, the allowance price cannot be predicted precisely. Rather, to evaluate potential economic impacts, the allowance price is estimated based on a range of reasonable scenarios of technological opportunities and behavioral responses.

In 2010, ARB conducted a joint analysis of the AB 32 Scoping Plan with Charles River Associates and Professor David Roland-Holst of the University of California, Berkeley. The estimated 2020 allowance price in these three analyses ranged from about $20 to $100.[94, 95, 96] The range of prices in those analyses depended on assumptions about the success of other AB 32 policies and whether offsets were allowed for compliance.

Appendix E: Setting the Program Emissions Cap, presents detail on the number of allowances that will be made available and the reduction path for the proposed regulation. Cumulative projected emissions over 2012 through 2020 total 2,948 $MMTCO_2e$. The number of allowances that would be made available over those years is 2,674 million. The difference between these two numbers, 273 million, represents the required program reductions, some of which may be achieved through projects that generate offset credits. However, approximately 123 million allowances will be placed in the Reserve and only made available at the prescribed reserve prices. For allowance prices to remain below the reserve prices—that is, for none of the allowances from the Reserve to be used—approximately 397 million metric tons must be reduced by 2020.

Table VIII-2 presents the potential cumulative reductions for the years 2012 through 2020 estimated in Energy 2020 that could occur at the various price levels, along with an estimate of the number of offsets that could be available for compliance at those prices. The number of offsets available each year is calculated using the following offset supply curve:

$$Q \text{ (millions)} = (P - 8) / 0.75$$

Q is the quantity of offsets available at price P in a given year

Regulations implementing AB 32 complementary policies in capped sectors that are either adopted or are likely to be adopted, such as the 33 Percent Renewable

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[94] http://www.arb.ca.gov/cc/scopingplan/economics-sp/updated-analysis/updated_sp_analysis.pdf
[95] http://www.arb.ca.gov/board/books/2010/042110/10-3-6-david-roland-holst-panelist.pdf
[96] http://www.arb.ca.gov/cc/scopingplan/economics-sp/meetings/042110/bernstein.pdf

Energy Standard, the Low Carbon Fuel Standard, and the California Advanced Clean Cars Program, could account for more than 150 million cumulative tons of reductions.[97] Further reductions are anticipated from other complementary policies in capped sectors, such as aggressive energy efficiency or changes in land use and transportation planning. Finally, there would be additional reductions that come from price-induced conservation that are not captured in the Energy 2020 model.

Based on the assumptions about internal reductions available to capped sectors, the availability of offsets and the reductions from AB 32 complementary policies, staff believe that the 397 million cumulative metric ton reduction requirement is likely to be met at an allowance price that falls within the range of $15 to $30 per metric ton in 2020. For example, at an allowance price of $30 metric ton, estimated reductions by covered sources total 114 million, while an estimate of offsets available at a $30/metric ton price total 177 million. Therefore, to achieve the 397 metric ton reduction, the complementary policies would have to provide for slightly over 100 million metric tons in reductions. To the extent that they do more, a lower allowance price would occur.

The 2020 prices used in this analysis include those that could be considered likely given the previous analyses and more recent estimates about emissions: prices of $10 and $20/metric ton at the start of the program in 2012, which equate to $15 and $30/metric ton in the year 2020; and the reserve trigger prices where additional allowances would be made available as part of the proposed cost containment mechanism: $40, $45, and $50/metric ton in 2012, which equate to $60, $67, and $75/metric ton in the year 2020.[98]

Table VIII-2: Estimated Energy 2020 Cumulative Emissions Reductions, 2012–2020

2020 Allowance Prices per Metric Ton of CO_2e	Expected Price Range		Reserve Prices		
	$15	$30	$60	$67	$75
Internal Reductions (Energy 2020)	99	114	148	156	166
Offsets	42	177	225	228	231
Total Available Reductions	141	291	373	384	397

[97] *Updated Economic Analysis of California's Climate Change Scoping Plan: Staff Report to the Air Resources Board.* March 2010. http://www.arb.ca.gov/cc/scopingplan/economics-sp/updated-analysis/updated_sp_analysis.pdf.

[98] The estimated increase in prices from 2012 to 2020 is based on a growth rate of 5 percent per year rounded to the nearest dollar. The auction floor price and prices for the allowance reserve all increase under the proposed regulation by 5 percent per year, plus inflation.

The range of allowance prices used in this analysis is intended to illustrate the possible economic effects of several uncertainties. If the economy grows faster than currently forecast, or the other Scoping Plan measures achieve fewer cumulative reductions than expected, the cap-and-trade program would need to provide more reductions than previously estimated. On the other hand, if fewer offsets are available or the reductions estimated by Energy 2020 are more expensive than assumed, the cap-and-trade program would need to produce the same amount of reductions but would do so at higher allowance prices.

F. Energy 2020 Estimated Price and Expenditures Changes

The estimated impacts on the cost of using fossil-based energy in 2020 from the proposed cap-and-trade program are detailed in Table VIII-3. These estimates are based on full pass-through of allowance value to the consumers. While the analysis indicates that the cap-and-trade program will likely produce some increases in the cost of using energy, increased investments in efficiency and alternative fuels will also result in an overall decrease in fuel expenditures, as discussed below. The manner in which allowances are distributed is also likely to affect impacts. The potential effects of different allocation methods are discussed in Appendix J: Allowance Allocation and Appendix K: Leakage Analysis.

The change in energy costs induces consumers of energy to increase their energy efficiency. For example, a higher price on gasoline and diesel may induce some consumers to switch to smaller vehicles that are both more fuel-efficient but less expensive than the larger vehicles chosen without cap-and-trade. This analysis does not assume that economies of scale or learning effects cause the price of energy efficiency or delivering of alternative low-carbon fuels to decrease from those in the initial case, though such effects are likely.

Table VIII-3: Energy 2020 Estimated Cap-and-Trade Energy Price Changes in 2020

2020 Allowance Prices per Metric Ton of CO_2e:	Expected Price Range		Reserve Prices		
	$15	$30	$60	$67	$75
Residential					
Electric	1%	3%	6%	7%	9%
Natural Gas	7%	14%	28%	31%	35%
Oil	5%	10%	21%	23%	26%
LPG	2%	4%	9%	10%	11%
Commercial					
Electric	1%	3%	7%	8%	9%
Natural Gas	8%	16%	32%	36%	40%
Oil	6%	12%	24%	26%	29%
LPG	3%	5%	11%	12%	13%
Industrial					
Electric	1%	3%	8%	9%	11%
Natural Gas	6%	13%	26%	29%	32%
Coal	54%	107%	215%	240%	269%
Oil	4%	8%	17%	18%	21%
Transportation					
Gasoline	4%	8%	15%	17%	19%
Diesel	2%	4%	9%	10%	11%

Price changes reflect only the contribution of cap-and-trade and do not reflect changes from other AB 32 policies.

Table VIII-4: Energy 2020 Estimated 2020 Changes in Annualized Expenditures from Cap-and-Trade ($[2007]Millions)

details the estimated 2020 changes in investment and fuel expenditures induced by the cap-and-trade program. A more detailed breakdown of expenditures is provided in Appendix N: Supporting Documentation for the Economic Analysis. The investments in devices are annualized using a 5 percent real capital recovery factor over the life of the equipment. The fuel expenditures do not reflect the allowance value. At the prices modeled, the annual allowance value could be an additional $5 to $25 billion in 2020. The allowance value represents a transfer of income from among sectors of the economy. The allowance value is accounted for separately from the expenditures in the economy-wide analysis by increasing prices in the E-DRAM model.

The total cost estimates include both the change in fuel expenditures and the change in investment costs. These cost estimates become the inputs for the E-DRAM model to estimate the economy-wide impacts of the cap-and-trade program. As seen in Table VIII-4, rising energy costs drive purchases of devices of greater efficiency, which are generally more expensive at the outset. However

the increase in fuel savings offsets much of this expenditure. As a result, the net change in expenditures remains fairly constant over the range of prices.

Table VIII-4: Energy 2020 Estimated 2020 Changes in Annualized Expenditures from Cap-and-Trade ($[2007]Millions)

2020 Allowance Prices per Metric Ton of CO_2e:	Expected Price Range		Reserve Prices		
	$15	$30	$60	$67	$75
Device Investment	$3,359	$3,472	$3,709	$3,770	$3,847
Process Investment	$52	$93	$170	$187	$206
Operating and Maintenance	$1,007	$1,073	$1,203	$1,232	$1,266
Fuel Expenditures*	($2,874)	($3,245)	($3,944)	($4,102)	($4,286)
Total	$1,544	$1,393	$1,138	$1,086	$1,034
2020–2012 Total Change	$5,069	$4,530	$3,584	$3,390	$3,185
	Percent Change from No Policy Case				
Device Investment	1.8%	1.8%	1.9%	2.0%	2.0%
Process Investment	0.0%	0.0%	0.1%	0.1%	0.1%
Operating and Maintenance	11.9%	12.6%	14.2%	14.5%	14.9%
Fuel Expenditures	-1.9%	-2.1%	-2.6%	-2.7%	-2.8%
Total	0.2%	0.2%	0.2%	0.2%	0.2%
2020–2012 Total Change	0.1%	0.1%	0.1%	0.1%	0.1%

*Fuel expenditures do not include allowance value.

G. Economy-Wide Impacts from the Cap-and-Trade Program

To assess the economy-wide effects of the cap-and-trade program, the estimated allowance price and the expenditure changes and offset expenditures are used as inputs to the E-DRAM model. A model such as E-DRAM is not meant to predict which sectors may experience increased growth because of new opportunities brought on by limiting GHG emissions, such as those that design or manufacture renewable technologies, or to predict the creation and growth of jobs in sectors driven by the production of cleaner and more efficient technologies. Because E-DRAM is based on historical data, the economy and the way the economy uses inputs to production such as energy or labor looks very similar in the future as it does today, only larger.

The results shown in Table VII-5 use the costs presented in Table VIII-5 and assume that all allowance value is recycled as income to California consumers. Allowance value may be redirected to a number of different uses. In E-DRAM, the manner in which allowance value is redistributed has a greater effect on the impact to specific groups and less of an effect at the state level, as long as the value remains in-state. The 2020 state-level impacts are presented in Table VIII-5.

These results provide insight into the potential range of impacts that the cap-and-trade program could have on the California economy. The estimated impacts show relatively small changes in economic growth when compared to growth otherwise expected over 2007 to 2020. The Reference case forecast used in the E-DRAM model assumes that California gross state product will grow by about 35 percent between 2007 and 2020. With imposition of the cap-and-trade program, the annual average growth in gross state product is reduced by only about one-tenths of 1 percent, under the expected allowance price assumption. These results indicate that at the state level, the cap-and-trade program does not have a significant adverse impact on California business or consumers as a whole, and that the rate of job creation under the proposed regulation is very similar to currently projected rates.

Table VIII-5: E-DRAM Estimated 2020 Economic Impacts of the Cap-and-Trade Program $(2007)

2020 Allowance Prices per Metric Ton of CO_2e:	2007	2020 No Cap and Trade	Expected Price Range		Reserve Prices		
			$15	$30	$60	$67	$75
Gross State Product ($ Billions)	$1,845	$2,498	$2,495	$2,491	$2,484	$2,482	$2,481
Personal Income ($ Billions)	$1,492	$2,024	$2,021	$2,019	$2,015	$2,014	$2,013
Income Per Capita ($ Thousands)	$39.3	$46.0	$46.0	$46.0	$45.9	$45.9	$45.9
Labor Demand (Millions)	16.35	18.40	18.34	18.30	18.22	18.20	18.18
			Percent Change from No Policy Case				
Gross State Product	-	-	-0.1%	-0.3%	-0.6%	-0.6%	-0.7%
Personal Income	-	-	-0.1%	-0.2%	-0.5%	-0.5%	-0.6%
Income Per Capita	-	-	0.0%	-0.1%	-0.2%	-0.2%	-0.2%
Labor Demand	-	-	-0.3%	-0.6%	-1.0%	-1.1%	-1.2%
		Annual Average Growth 2007–2020					
Gross State Product	-	2.4%	2.3%	2.3%	2.3%	2.3%	2.3%
Personal Income	-	2.4%	2.4%	2.4%	2.3%	2.3%	2.3%
Income Per Capita	-	1.2%	1.2%	1.2%	1.2%	1.2%	1.2%
Labor Demand	-	0.9%	0.9%	0.9%	0.8%	0.8%	0.8%

It is not possible to verify all of the expenditure data used in Energy 2020, so staff conducted a sensitivity analysis to evaluate the potential for expenditures to be greater than estimated by the model. In this sensitivity case, the change in device investment, process investment, and operating and maintenance expenditures used in the previous example (Table VIII-4) were doubled. Since the change in investment and operating and maintenance expenditures for

passenger cars and trucks were negative in the initial analysis, reflecting the purchase of smaller less expensive vehicles, these values were set to zero.

The 2020 state-level impacts for the cost sensitivity are presented in Table VIII-6. The effect of doubling all expenditures except for fuel expenditures results in slightly greater economic impacts, primarily at the lower allowance prices. At higher allowance prices, the estimated impacts are driven more by the allowance value and less by the expenditures.

Table VIII-6: E-DRAM Estimated 2020 Economic Impacts of the Cap-and-Trade Program With Device, Process, and Operating and Maintenance Expenditures Doubled $(2007)

2020 Allowance Prices per Metric Ton of CO_2e:	2007	2020 No Cap-and-Trade	Expected Price Range		Reserve Prices		
			$15	$30	$60	$67	$75
Gross State Product ($ Billions)	$1,845	$2,498	$2,488	$2,484	$2,476	$2,474	$2,472
Personal Income ($ Billions)	$1,492	$2,024	$2,016	$2,013	$2,008	$2,007	$2,005
Income Per Capita ($ Thousands)	$39.3	$46.0	$45.9	$45.9	$45.8	$45.8	$45.8
Labor Demand (Millions)	16.35	18.40	18.31	18.27	18.18	18.16	18.13
			Percent Change from No Policy Case				
Gross State Product	-	-	-0.4%	-0.6%	-0.9%	-1.0%	-1.0%
Personal Income	-	-	-0.4%	-0.5%	-0.8%	-0.9%	-0.9%
Income Per Capita	-	-	-0.2%	-0.3%	-0.4%	-0.4%	-0.4%
Labor Demand	-	-	-0.5%	-0.7%	-1.2%	-1.3%	-1.5%
		Annual Average Growth 2007–2020					
Gross State Product	-	2.4%	2.3%	2.3%	2.3%	2.3%	2.3%
Personal Income	-	2.4%	2.3%	2.3%	2.3%	2.3%	2.3%
Income Per Capita	-	1.2%	1.2%	1.2%	1.2%	1.2%	1.2%
Labor Demand	-	0.9%	0.9%	0.9%	0.8%	0.8%	0.8%

H. Cost-Effectiveness

This section discusses the cost-effectiveness of the proposed regulation. AB 32 requires the Board to consider cost-effectiveness of each GHG control measure it adopts. The values must be expressed in dollars per metric ton of CO_2e emissions reduced. AB 32 does not specify what costs should be included in these calculations nor does it provide criteria to assess if a regulation is cost-effective, beyond directing ARB to adopt regulations "to achieve the maximum technologically feasible and cost-effective reductions...in furtherance of achieving the statewide greenhouse gas emissions limit" (HSC §38562[a]).

A cap-and-trade program is a market-based mechanism that helps establish a common marginal cost of reductions (i.e., a common cost of the next action to be taken to reduce emissions) across all covered entities by providing for the trading of allowances. This common cost will encourage those who can reduce emissions most cheaply to do so, achieving the pollution reduction at the lowest cost to society. The measure of cost-effectiveness is therefore the estimated allowance price.

As previously discussed, many factors influence the allowance price, making it impossible to predict with precision. Rather than attempting to predict a specific price, this analysis has used a series of time profiles based on reasonable estimates of technological opportunities and behavioral responses under various scenarios. The results show that the needed reductions could be achieved at allowance prices in 2020 in the range of $15 to $30 per metric ton. Should likely prices not prove accurate, the program has established price containment measures that would come into effect to mitigate excessively high prices. Table VIII-7 shows the cost-effectiveness of the proposed cap-and-trade regulation in 2020 for the expected range of prices.

Table VIII-7: Cost-Effectiveness of the Proposed Cap-and-Trade Regulation in 2020

($ per Metric Ton of CO_2e)	Expected Price Range
Allowance Price in 2020	$15–$30

I. Potential Impacts on Small Business

Very few small businesses have enough emissions to be regulated directly under the cap-and-trade program. Most foreseeable small business impacts will result from changes in energy expenditures. Therefore, this analysis focuses on how implementation of the program could affect expenditures that small businesses make on electricity and natural gas and how such shifts could affect their profitability. ARB will continue to seek ways to measure impacts and report to the Board as the program is implemented.

Under a contract with ARB, Dun and Bradstreet (D&B) provided ARB with data from a statistical data model that estimates the portion of revenue that businesses spend on energy. The model is based on D&B marketing files from approximately 17 million businesses nationwide including over 2.1 million in California. The annual spending on electricity and natural gas was calculated for affected businesses as follows:

- D&B collected data on monthly electricity and natural gas bills for approximately 628,000 businesses nationally from 18 utilities nationwide, including two California utilities, from April 2007 to March 2008.

- Annual spending on electricity and natural gas were calculated for these businesses by summing the monthly bills.
- Of these 628,000 businesses, D&B has revenue data for 210,000.
- Revenue data were available for a greater number of large businesses in the sample. Thus, the sample distribution was adjusted to represent the true universal distribution of the D&B database of 17 million businesses.

Staff analyzed the California industries with the greatest expenditures on retail electricity and natural gas as a percentage of their revenue. These industries are primarily service-related and serve local markets. The price changes displayed in Table VIII-3 were used to estimate the change in the share of revenue spent on energy. This estimate assumes that these industries make no changes in their energy use in response to the price changes. Table VIII-8 reports the results. Additional detail on this analysis is provided in Appendix N: Supporting Documentation for the Economic Analysis.

Under the likely range of allowance prices, most sectors experience less than a 2 percent change in the share of revenue spent on energy. Even at the highest reserve price, most sectors experience less than a 4 percent change. The majority of the listed business categories are those that serve local markets such as trailer parks and camps, hotels, barbershops, bakeries, etc. Out-of-state businesses cannot serve these local markets. As a result, most California small businesses are not likely to face competitiveness issues relative to out-of-state businesses.

The potential impact estimated here may be high because small businesses, like any other businesses, are likely to respond to the increase in energy prices by investing in energy-efficient technologies to achieve energy savings. In light of many public incentive programs available, most small businesses should not have difficulties in obtaining the required capital for investment in energy-efficient technologies. The savings from electricity efficiency improvements are likely to partially offset or mitigate the impact of any increase in electricity prices and could mean decreased energy bills even in the face of increased prices.

J. Potential Impacts on California Business Competitiveness

ARB has closely analyzed the potential impact of a cap-and-trade program on California business competitiveness, and the proposed regulation includes methods to reduce competitiveness loss though the allocation process, such as through output-based updated free allocation. The proposed allowance distribution system is designed to reduce the potential for competitive losses to California business such that there should be minimal impact. The allocation system is discussed in Appendix J: Allowance Allocation and Appendix K: Leakage Analysis.

Additionally, California is working closely with our partners in the Western Climate Initiative (WCI) and with the federal government to implement a larger climate change program to further reduce the potential for competitiveness loss that could arise from the implementation of a California-only cap-and-trade program. The proposed regulation has been designed to facilitate future linkage with other cap-and-trade programs.

Table VIII-8: Range of Impact on Average Percentage of Revenue Spent on Energy

SIC	Business Category	Energy Expenditures/ Revenue (without program)	Change in Energy Expenditures/ Revenue at Given Cap-and-Trade Program Allowance Prices (2020 Allowance Prices per Metric Ton of CO_2e)				
			Expected Price Range		Reserve Prices		
			$15	$30	$60	$67	$75
7215	Coin-Operated Laundries and Cleaning	22.1%	1.4%	2.7%	5.6%	6.2%	7.0%
7219	Laundry and Garment Services	15.3%	0.8%	1.5%	3.2%	3.6%	4.0%
8641	Civic and Social Associations	14.4%	0.6%	1.2%	2.5%	2.8%	3.1%
7021	Rooming and Boarding Houses	14.3%	0.6%	1.3%	2.7%	3.1%	3.5%
7041	Membership-Basis Organization Hotels	13.7%	0.6%	1.3%	2.7%	3.0%	3.4%
7033	Trailer Parks and Campsites	13.3%	0.5%	1.1%	2.2%	2.5%	2.8%
7241	Barber Shops	11.9%	0.5%	1.0%	2.1%	2.4%	2.7%
6719	Holding Companies	11.8%	0.5%	1.0%	2.1%	2.4%	2.7%
7011	Hotels and Motels	11.3%	0.5%	1.0%	2.0%	2.3%	2.6%
7032	Sporting and Recreational Camps	11.0%	0.3%	0.7%	1.5%	1.7%	1.9%
8351	Child Day-Care Services	10.3%	0.4%	0.9%	1.8%	2.1%	2.3%
8231	Libraries	10.2%	0.4%	0.7%	1.6%	1.7%	2.0%
5461	Retail Bakeries	10.1%	0.3%	0.7%	1.5%	1.7%	1.9%
5813	Drinking Places	10.0%	0.4%	0.8%	1.6%	1.8%	2.0%
7231	Beauty Shops	9.9%	0.4%	0.8%	1.6%	1.8%	2.1%
8361	Residential Care	8.9%	0.3%	0.7%	1.4%	1.6%	1.8%
4941	Water Supply	8.7%	0.3%	0.6%	1.3%	1.5%	1.6%
7217	Carpet and Upholstery Cleaning	8.0%	0.2%	0.5%	1.0%	1.2%	1.3%
5441	Candy, Nut, and Confectionery Stores	7.8%	0.2%	0.5%	1.0%	1.1%	1.3%

SIC = Standard Industrial Classification code

K. Potential Impacts on Individual Consumers

Individual consumers will not be directly affected by the cap-and-trade program, but will see indirect effects from changes in energy prices. Households that use less carbon (directly via energy consumption and indirectly via consumption of goods and services that are produced or distributed using energy) will be less affected than those that use more carbon. Assessing how these price changes affect consumer well-being depends on whether and how income from auction of allowances is returned to consumers. Further discussion on the uses of allowance value for compensation of households can be found in Appendix J: Allowance Allocation.

Table VIII-9: Energy 2020 Estimated 2020 Changes in Residential Annualized Expenditures

	Expected Price Range		Reserve Prices		
2020 Allowance Prices per Metric Ton of CO_2e:	**$15**	**$30**	**$60**	**$67**	**$75**
Residential	**$(2007)Millions**				
Investment* and O+M	1,484	1,643	1,960	2,034	2,122
Fuel**	(337)	(411)	(547)	(577)	(612)
Total	1,146	1,232	1,413	1,457	1,510
Passenger					
Investment* and O+M	(106)	(192)	(363)	(403)	(448)
Fuel**	(484)	(558)	(700)	(732)	(768)
Total	(591)	(751)	(1,063)	(1,135)	(1,216)
	Percent Change from No Policy Case				
Residential					
Investment* and O+M	0.8%	0.9%	1.0%	1.1%	1.1%
Fuel**	-1.4%	-1.7%	-2.3%	-2.4%	-2.6%
Total	0.5%	0.6%	0.7%	0.7%	0.7%
Passenger					
Investment* and O+M	-0.1%	-0.1%	-0.2%	-0.3%	-0.3%
Fuel**	-0.8%	-0.9%	-1.2%	-1.2%	-1.3%
Total	-0.3%	-0.3%	-0.5%	-0.5%	-0.6%

*Includes investment in devices (mechanical end-uses of energy, such as lighting, space heating or air conditioning) and process investment (e.g., building shell improvements).
**Fuel expenditures do not include allowance value.

Table VIII-9 details the estimated 2020 changes in investment, operating, and maintenance and fuel expenditures for the residential and passenger sectors

resulting from the cap-and-trade program.[99] As discussed earlier, devices are mechanical end-uses of energy, such as lighting, space heating, or air conditioning while process reflects building shell improvements. The fuel expenditures do not reflect the allowance value. The combined share of the allowance value from the Residential and Passenger sectors could be more than 40 percent. The allowance value is treated separately from the expenditures in the economy-wide analysis.

Under any of the prices analyzed, consumer residential net spending in 2020 increases by just over one-half of a percent. Passenger investment decreases, reflecting some price-induced shifts to smaller, less-expensive vehicles.

L. Potential Cost to Local, State, and Federal Agencies

The proposed regulation would impose direct requirements on local government agencies, specifically municipal utilities, that are directly responsible for emitting over 25,000 $MTCO_2e$ per year. However, municipal utilities should be able to use their existing administrative mechanisms to pass on the fee costs to their customers. In this case there would be no net fiscal impact. State and Local governments will face higher prices for products they purchase as businesses pass on costs.

The proposed regulation would impose direct compliance requirements on the State Department of Water Resources, which directly imports power from a coal-fired plant with which it has an ownership contract through 2013. However, there would be no net fiscal impact if DWR is able to use its existing administrative mechanisms to pass the fee costs on to customers. Based on 2006 electricity imports, DWR would incur direct costs of about $19.5 million during 2012. ARB understands that the DWR contract for Reid Gardner power plant expires in 2013, so DWR should owe no costs after the contract expires.

The proposed regulation will impose direct compliance requirements on several state universities. Purchase of allowances could be about $10 million.

Table VIII-10 presents an estimate of the potential allowance costs for government agencies in California.

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[99] The passenger sector includes passenger cars and trucks, and also contains expenditures from commercial passenger transit, such as buses or trains.

Table VIII-10: Government Annual Allowance Purchase Cost

$(2007)Millions	Initial	Ongoing
University of California	$7.8	$7.8
California State University	$2.3	$2.3
DWR (Reid Gardner)*	$19.5	$0.0
Total	$29.7	$10.2

*DWR contract expires in 2013.

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IX SUMMARY AND RATIONALE FOR PROPOSED REGULATION

The proposed cap-and-trade Regulation is designed to reduce emissions of greenhouse gases (GHG) by establishing a cap covering about 85 percent of the State's GHG emissions and allow trading to ensure cost-effective emissions reductions. This section discusses the requirements and rationale for each provision of the proposed regulation.

Subarticle 1. Table of Contents.

Section 95800. Table of Contents.

Summary of Section 95800.

This section provides the table of contents for the regulation.

Rationale for Section 95800.

This section is necessary to provide the structure of the regulation and help guide the public through the regulatory provisions.

Subarticle 2. Purpose and Definitions.

Section 95801. Purpose.

Summary of Section 95801.

This section states the purpose of the regulations. Specifically, the purpose of this regulation is to reduce greenhouse gas emissions by establishing an aggregate statewide limit on GHG emissions from sources specified in this regulation.

Rationale for Section 95801.

This section is needed to ensure that the regulated public and other market participants understand that this regulation will reduce emissions to help achieve the goals of AB 32.

Section 95802. Definitions.

Summary of Section 95802.

This section proposes definitions to the terms used in the regulation.

Rationale for Section 95802.

It is necessary that ARB defines its terms as they apply to the California cap-and-trade program. Most of these terms are used in other articles and titles in the California Code of Regulations, Government Code sections or statutes, and it is

necessary that ARB be consistent with existing definitions to the extent that they apply to this regulation.

Subarticle 3. Applicability.

Section 95810. Covered Gases.

Summary of Section 95810.

This section states the greenhouse gases (GHGs) that are required to be covered in AB 32.

Rationale for Section 95810.

This section is required to identify the GHGs to which this regulation would apply. These gases were included because they are identified in AB 32.

Section 95811. Covered Entities.

Summary of Section 95811(a).

Subsection (a) of the proposed regulation identifies the operator of a facility within California that has a compliance obligation as stated in subsections (a)(1) through (a)(12).

Rationale for Section 95811(a).

This provision is required to identify the industrial processes or operations to which this regulation would apply.

Summary of Section 95811(a)(1), Cement Production.

Subsection (a)(1) proposes to cover annual stationary combustion and process emissions from cement production.

Rationale for Section 95811(a)(1).

It is necessary to include these producers because cement production emissions represent a large share of California stationary source greenhouse gas emissions.

Summary of Section 95811(a)(2), Cogeneration.

Subsection (a)(2) proposes to cover emissions from electricity and thermal output generated at cogeneration units.

Rationale for Section 95811(a)(2).

It is necessary to include emissions from cogeneration units because these units are widely used by industries and represent a large share of California GHG emissions. The use is expected to grow and the efficiency is expected to improve.

Summary of Section 95811(a)(3), Glass Production.

Subsection (a)(3) proposes to cover annual stationary combustion and process emissions from glass production.

Rationale for Section 95811(a)(3).

It is necessary to include emissions from glass production because the process is highly emissions intensive and represents California GHG emissions.

Summary of Section 95811(a)(4), Hydrogen Production.

Subsection (a)(4) proposes to cover annual emissions associated with hydrogen production processes, flares, and destruction devices.

Rationale for Section 95811(a)(4).

It is necessary to include emissions from hydrogen production because the process is highly emissions intensive and represents California GHG emissions.

Summary of Section 95811(a)(5), Iron and Steel Production.

Subsection (a)(5) proposes to cover annual combustion and process emissions associated with iron and steel production.

Rationale for Section 95811(a)(5).

It is necessary to include emissions from iron and steel production because the process is emissions intensive and represents California GHG emissions.

Summary of Section 95811(a)(6), Lime Manufacturing.

Subsection (a)(6) proposes to cover annual combustion and process emissions associated with quick lime production.

Rationale for Section 95811(a)(6).

It is necessary to include emissions from lime production because the process is emissions intensive and represents California GHG emissions.

Summary of Section 95811(a)(7), Nitric Acid Production.

Subsection (a)(7) proposes to cover annual N_2O mass emissions from each nitric acid train.

Rationale for Section 95811(a)(7).

It is necessary to include emissions from nitric acid production because it is very emissions intensive and represents California GHG emissions.

Summary of Section 95811(a)(8), Oil and Natural Gas Systems.

Subsection (a)(8) proposes to cover stationary and process sources of the following: offshore petroleum and natural gas production facilities, onshore natural gas processing facilities, onshore natural gas transmission compression facilities, underground natural gas storage facilities, liquefied natural gas storage facilities, and liquefied natural gas import and export facilities.

Rationale for Section 95811(a)(8).

It is necessary to cover emissions from oil and natural gas systems as identified in this subsection because production activities are managed best at the state level, where regional and local conditions are understood and where regulations can be tailored to fit the needs of the local environment. Natural gas systems are proposed as additions to those process sources included in the current ARB MRR, including cement production, power plants, petroleum refineries, and hydrogen plants. The ARB staff proposal would affect all petroleum and natural production operations in California where an entity's emissions equal or exceed the cap-and-trade threshold.

Summary of Section 95811(a)(9), Petroleum Refining.

Subsection (a)(9) proposes to cover emissions from calciners, cat cracking, other cat regeneration, process vents, asphalt production, sulfur recovery, flares, and destruction devices.

Rationale for Section 95811(a)(9).

It is necessary to include emissions from petroleum refineries because refining processes emissions represent a large share of California stationary source greenhouse gas emissions and are emissions intensive.

Summary of Section 95811(a)(10), Pulp and Paper Manufacturing.

Subsection (a)(10) proposes to cover annual emissions from a process in the manufacture of paper and paperboard, which can be split into three steps: pulp making, pulp processing, and paper/paperboard production.

Rationale for Section 95811(a)(10).

It is necessary to include emissions from pulp and paper because during the manufacturing process, the individual fibers formed into paper sheets (called pulp) create GHG emissions.

Summary of Section 95811(a)(11), Self-Generation of Electricity.

Subsection (a)(11) proposes to cover emissions from electricity generated for consumption solely onsite.

Rationale for Section 95811(a)(11).

It is necessary to include emissions from electricity self-generation because it is a significant source of emissions that is not captured elsewhere.

Summary of Section 95811(a)(12), Stationary Combustion.

Subsection (a)(12) proposes to cover annual stationary combustion emissions that have not been captured under subsection (a)(1) through (a)(11).

Rationale for Section 95811(a)(12).

It is necessary to include emissions from stationary combustion because it captures steam-producing units that combust municipal solid waste or solid biomass fuels, and it generates GHGs.

Summary of Section 95811(b), First Deliverers of Electricity.

Subsection (b) proposes to cover first deliverers of electricity delivered to the California electricity transmission and distribution system.

Rationale for Section 95811(b).

It is necessary to include electricity deliverers because they represent a significant amount of emissions from relatively few sources and accurate emissions reporting and monitoring methods exist for these types of sources.

Summary of Section 95811(b)(1), Electricity Generating Facilities.

Subsection (b)(1) proposes to cover operators of electricity generating facilities in California that deliver electricity to the California electricity transmission and distribution system.

Rationale for Section 95811(b)(1).

It is necessary to include emissions from all electricity consumed in the State according to AB 32 (HSC 38530(b)(2)).

Summary of Section 95811(b)(2), Electricity Importers.

Subsection (b)(2) proposes to cover electric power entities that import electricity.

Rationale for Section 95811(b)(2).

It is necessary to include emissions from electric power entities, California retail providers, multijurisdictional retail providers, marketers, Western Area Power Administration (WAPA), and California Department of Water Resources (DWR) because emissions from this sector account for a large share of California GHG emissions.

Summary of Section 95811(c), Suppliers of Natural Gas.

Subsection (c) proposes to include emissions associated with the distribution or use of natural gas in California.

Rationale for Section 95811(c).

It is necessary to include emissions from distributers and users of natural gas because combustion of natural gas is responsible for 26 percent of GHG emissions in California.

Summary of Section 95811(c)(1), Public Utility Gas Corporation.

Subsection (c)(1) proposes to include combustion emissions associated with public utility gas corporations operating in California.

Rationale for Section 95811(c)(1).

It is necessary to include combustion emissions from public utility gas corporations because it is at the most upstream point possible for natural gas consumption. LPG consignees who import LPG into California and natural gas liquid fractionators are required to report emissions for LPG, to be consistent with the desire of cap-and-trade to include suppliers of LPG as covered entities. Local Distribution Companies (LDC), which are divided into two categories in California—public utility gas corporations and publicly owned natural gas utilities—are required to report

Summary of Section 95811(c)(2), Publicly Owned Natural Gas Utilities.

Subsection (c)(2) proposes to include combustion emissions associated with publicly owned natural gas utilities operating in California.

Rationale for Section 95811(c)(2).

It is necessary to include combustion emissions from publicly owned natural gas utilities because it captures emissions at the most upstream point possible for natural gas consumption.

Summary of Section 95811(c)(3), Operators of Intrastate Pipelines.

Subsection (c)(3) proposes to include combustion emissions associated with operators of an intrastate pipeline, not included in subsections (c)(1) or (c)(2), that distributes natural gas directly to end users.

Rationale for Section 95811(c)(3).

It is necessary to include combustion emissions from every natural gas producer or consumer at the most upstream point possible for intrastate pipeline owners and operators that distribute natural gas for use in California.

Summary of Section 95811(d), Suppliers of RBOB and Distillate Fuel Oil.

Subsection (d) proposes to include offsite combustion emissions that result from petroleum products produced in or imported into California. Suppliers of these fuels include a position holder of one or more of the following fuels, or an enterer that imports one or more of the following fuels into California: reformulated blendstock for oxygenate blending (RBOB), Distillate Fuel Oil No. 1, and Distillate Fuel Oil No. 2.

Rationale for Section 95811(d).

It is necessary to include emissions that result from combustion of petroleum products that are mainly used for transportation purposes because these fuels result in a large share of the State's GHG emissions.

Summary of Section 95811(d)(1), RBOB.

Subsection (d)(1) proposes to include tailpipe combustion emissions that result from blended fuels that contain RBOB produced in or imported into California. Suppliers of RBOB include a position holder or an enterer that imports RBOB into California.

Rationale for Section 95811(d)(1).

It is necessary to include tailpipe combustion emissions from RBOB because they account for a large share of GHG emissions in California.

Summary of Section 95811(d)(2), Distillate Fuel Oil No. 1.

Subsection (d)(2) proposes to include offsite combustion emissions that result from Distillate Fuel Oil No. 1 produced in or imported into California. Suppliers of this fuel include a position holder or an enterer that produces or imports Distillate Fuel Oil No. 1. The first point of receipt at the terminal is the actual point of regulation.

Rationale for Section 95811(d)(2).

It is necessary to include tailpipe combustion emissions from Distillate Fuel Oil No. 1 because they account for a large share of GHG emissions in California.

Summary of Section 95811(d)(3), Distillate Fuel Oil No. 2.

Subsection (d)(3) proposes to include offsite combustion emissions that result from Distillate Fuel Oil No. 2 produced in or imported into California. Suppliers of this fuel include a position holder or an enterer that produces or imports Distillate Fuel Oil No. 2. The first point of receipt at the terminal is the actual point of regulation.

Rationale for Section 95811(d)(3).

It is necessary to include tailpipe combustion emissions from Distillate Fuel Oil No. 2 because they account for a large share of GHG emissions in California.

Summary of Section 95811(e), Suppliers of Liquefied Petroleum Gas.

Subsection (e) proposes to include combustion emissions that result from liquefied petroleum gas produced in or imported into California. Suppliers include an operator of a refinery that produces liquid petroleum gas in California, an operator of a facility that fractionates natural gas liquids to produce liquid petroleum gas, and an importer of liquefied petroleum into California.

Rationale for Section 95811(e).

It is necessary to include emissions from suppliers of liquefied petroleum gas because these fuels result in a large share of the State's GHG emissions, when completely combusted.

Summary of Section 95811(e)(1) through (e)(3).

Subsections (e)(1) through (e)(3)propose to include combustion emissions resulting from liquid petroleum gas produced in or imported into California. Suppliers include an operator of a refinery that produces liquid petroleum gas in California, an operator of a facility that fractionates natural gas liquids to produce liquid petroleum gas, and an importer of liquefied petroleum into California.

Rationale for Section 95811(e)(1) through (e)(3).

It is necessary to include emissions from suppliers of liquefied petroleum gas because these fuels result in a large share of the State's GHG emissions, when completely combusted. The proposed revised regulation will affect all suppliers of natural gas, as well as consignees who import liquefied petroleum gas (LPG) into the State of California where annual amounts of supplied or imported fuel, when completely combusted or oxidized, equals or exceeds the threshold.

Summary of Section 95811 (f).

Section 95811(f) specifically includes CO_2 emissions from blended fuels.

Rationale for Section 95811 (f).

It is necessary to include emissions from suppliers of blended fuels because these fuels result in a large share of the state's GHG emissions.

Summary of Section 95811(g), Suppliers of Carbon Dioxide.

Subsection (f) proposes to include CO_2 emissions that result from the complete release of the product that they place into commerce. Suppliers of CO_2 must report the mass of CO_2 captured from production process units and extracted from production wells, and the mass of CO_2 that is imported and exported.

Rationale for Section 95811(g).

It is necessary to include emissions from suppliers of carbon dioxide because these products placed into commerce generate CO_2 which results in emissions of GHG.

Section 95812. Inclusion of Thresholds for Covered Entities.

Summary of Section 95812(a).

Subsection (a) establishes the inclusion thresholds for emissions associated with each covered entity based on its reported GHG emissions to U.S. EPA for the data year 2010. If an entity's 2010 reported emissions exceed the inclusion threshold, it will be classified as a covered entity when this regulation becomes effective. The inclusion threshold for each covered entity is based on the subset of GHG emissions that generate a compliance obligation for that entity.

Rationale for Section 95812(a).

This subsection is necessary to establish what the emissions threshold is based on and derived from.

Summary of Section 95812(b).

Subsection 95812(b) proposes that if an entity's aggregated, reported, or verified emissions in any data year from 2008 to 2010 equals or exceeds the thresholds in subsequent sections, the entity will be classified as a covered entity as of January 1, 2012.

Rationale for Section 95812(b).

This subsection is necessary to establish under what circumstances an entity can trigger the inclusion threshold for covered entities.

Summary of Section 95812(b)(1), Operators of Facilities.

Subsection (b)(1) establishes the inclusion threshold for emissions that result from facilities with operations and processes identified in section 95811(a). In their 2008–2009 program design recommendations, the WCI Partners expressed the desire to monitor what happens beneath the agreed-upon cap-and-trade threshold of 25,000 metric tons carbon dioxide equivalent ($MTCO_2e$) (WCI Design Recommendations 2009).[100] The Partners adopted a reporting threshold of 10,000 $MTCO_2e$, to enable monitoring for leakage of emissions from sources below the cap threshold and to assess whether the cap threshold was appropriately set. The Partners wanted to be able to recommend subsequent action if the cap threshold had unanticipated economic or emissions consequences, and the lower reporting threshold would inform their review of market impacts. Thus, the threshold is set at 25,000 $MTCO_2e$ for the data year 2010 and every year thereafter.

Rationale for Section 95812(b)(1).

This inclusion threshold captures emissions from facilities with the largest amount of emissions without including small facilities.

Summary of Section 95812(b)(2), First Deliverers of Electricity.

Subsection (b)(2) establishes the inclusion threshold for emissions that result from first deliverers of electricity.

Rationale for Section 95812(b)(2).

This subsection is necessary so first deliverers of electricity know the threshold they must exceed to be covered under the program.

Summary of Section 95812(b)(2)(A), Electricity Generating Facilities.

Subsection (a)(2)(A) proposes to include a threshold for emissions associated with in-state electricity generating facilities based on annual emissions from facilities at which the electricity originated. The threshold is set at 25,000 $MTCO_2e$ for the data year 2010 and every year thereafter.

Rationale for Section 95812(b)(2)(A).

This inclusion threshold captures emissions from facilities with the largest amount of emissions without including small facilities.

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[100] Western Climate Initiative (2008): Design Recommendations for the WCI Regional Cap-and-Trade Program. http://www.westernclimateinitiative.org/component/remository/general/design-recommendations/Design-Recommendations-for-the-WCI-Regional-Cap-and-Trade-Program/

Summary of Section 95812(b)(2)(B), Electricity Importers of Specified Electricity.

Subsection (b)(2)(B) proposes to include emissions that result from generating electricity imported from a specified facility out-of-state if that facility's annual GHG emissions are equal to or greater than 25,000 $MTCO_2e$ for the data year 2010 and every year thereafter.

Rationale for Section 95812(b)(2)(B).

This provision is necessary to set this emissions threshold to be comparable with in-state electricity generators, to comply with the interstate commerce clause.

Summary of Section 95812(b)(2)(C), Electricity Importers of Unspecified Electricity.

Subsection (b)(2)(C) proposes to include all emissions that result from generating electricity imported from unspecified sources out-of-state, meaning that a covered entity must account for all emissions from all unspecified electricity imports.

Rationale for Section 95812(b)(2)(C).

This provision is necessary to include all emissions that result from unspecified electricity imports because ARB cannot assign emissions to an unspecified facility.

Summary of Section 95812(c).

Subsection (c) proposes to establish a threshold for carbon dioxide suppliers. The threshold is 25,000 $MTCO_2e$ per year.

Rationale for Section 95812(c).

This provision is necessary because it proposes the threshold for carbon dioxide suppliers. The threshold is based on the sum of its imported and exported carbon dioxide into and out of California.

Summary of Section 95812(d).

Subsection (d) proposes to establish a threshold for emissions that result from the combustion of fuels produced or imported from in California.

Rationale for Section 95812(d).

This provision is necessary because it proposes the emissions threshold that will trigger an entity to be classified as a covered entity as of January 1, 2015.

Summary of Section 95812(d)(1), Fuel Suppliers.

Subsection (d)(1) proposes to establish under what circumstances fuel suppliers may trigger the inclusion threshold before coverage in 2015.

Rationale for Section 95812(d)(1).

This inclusion threshold captures emissions associated with suppliers with the largest amount of emissions without including small suppliers.

Summary of Section 95812(d)(2), Electricity Importers.

Subsection (d)(2) proposes to establish the threshold for an electricity importer of specified or unspecified source of electricity, which is zero.

Rationale for Section 95812(d)(2).

This inclusion threshold is necessary because it proposes the emissions threshold that will trigger an entity to be classified as a covered entity as of January 1, 2015.

Summary of Section 95812(e), Effect of Reduced Emissions on an Entity's Compliance Obligation.

Subsection (e) proposes the conditions for a covered entity to avoid a compliance obligation for a specified compliance period.

Rationale for Section 95812(e).

An entity that reduces its emissions, becomes more efficient, or produces less should not hold a compliance obligation for that compliance period, because it did not exceed the inclusion threshold for any year during that compliance period.

Summary of Section 95812(e)(1).

Subsection (e)(1) proposes to identify an entity whose reported GHG emissions drop below its annual threshold for an entire compliance period and will not hold a compliance obligation for that compliance period.

Rationale for Section 95812 (e)(1).

It is necessary to identify the period of time for which an entity's reported emissions drop below its respective threshold, to identify for which compliance period the entity does not hold a compliance obligation.

Summary of Section 95812 (e)(2).

Subsection (e)(2) proposes to identify an entity whose processes and operations shut down permanently. A covered entity must fulfill its compliance obligations for that compliance period during which it shuts down and will not be subject to a compliance obligation for the following compliance period and any thereafter. A

reporter is not required to verify its emissions for the first full year of non-operation following a permanent shutdown.

Rationale for Section 95812 (e)(2).

An entity that shuts down its operation and no longer emits GHGs should not hold a compliance obligation for compliance periods subsequent to the one in which it shuts down, because it will no longer exceed the inclusion threshold in subsequent compliance periods because, by default, its emissions will be zero. This provision is included to prevent unnecessary financial burden of verification to reporters that shut down their operations.

Section 95813. Opt-In Covered Entities.

Summary of Section 95813(a).

Subsection (a) proposes to include the entities in the categories identified in section 95811 that do not meet the inclusion threshold of section 95812 to voluntarily become a covered entity.

Rationale for Section 95813(a).

This provision is included to incentivize entities to implement more efficient processes and technologies to reduce their associated emissions, to receive a higher number of direct allocations of allowances based on the product output-based benchmarking methodology.

Summary of Section 95813(b).

Subsection (b) requires entities to apply for approval by the Executive Officer to be approved as an opt-in covered entity.

Rationale for Section 95813(b).

This provision is necessary so ARB can determine if an entity meets the requirements set forth in subsection (a).

Summary of Section 95813(c).

Subsection (c) proposes that all opt-in covered entities are subject to all regulatory requirements that apply to covered entities, including reporting, verification, and compliance obligations.

Rationale for Section 95813(c).

This provision is necessary so ARB can assign a compliance obligation to opt-in covered entities, and maintain program intensity.

Summary of Section 95813(d).

Subsection (d) proposes to allow eligible opt-in covered entities to receive direct allocations of allowances.

Rationale for Section 95813(d).

This provision is included to incentivize entities to implement more efficient processes and technologies to reduce their associated emissions, to receive a higher amount of direct allocations of allowances based on the product output-based benchmarking methodology.

Summary of Section 95813(e).

Subsection (e) proposes that the inclusion of opt-in covered entities will not affect the California GHG allowances budgets established in Table 6-1 of the Regulation.

Rationale for Section 95813(e).

This provision is included because staff is uncertain of how many opt-in covered entities will apply for approval by the Executive Officer. The allowance budgets cannot be adjusted each time an opt-in covered entity is approved because the cap is set in the regulation to provide certainty to market participants of how many compliance instruments are available in all years of the program.

Summary of Section 95813(f).

Subsection (f) proposes that an opt-in covered entity could opt out of the program at the end of each compliance period only if it has fulfilled its compliance obligations or has returned to ARB an equivalent number of allowances it received through direct allocations in that compliance period.

Rationale for Section 95813(f).

Staff proposes that an opt-in covered entity can opt out of the program because its emissions are below the inclusion threshold, and it is not required to participate in the program in the first place. Staff proposes that an opt-in covered entity must stay in the program until its triennial surrender obligation is completed after the compliance period ends.

Section 95814. Voluntarily Associated Entities and Other Registered Participants.

Summary of Section 95814(a)(1).

Subsection (a)(1) proposes that an entity not identified as a covered entity or an opt-in covered entity could voluntarily register with the accounts administrator to become a Voluntary Associated Entity. These entities may acquire and hold California Compliance Instruments and participate in auctions.

Rationale for Section 95814(a)(1).

This subsection is needed to allow entities that do not have a compliance obligation to participate in the cap-and-trade system. Qualifying entities may trade compliance instruments and voluntarily retire compliance instruments for the benefit of the environment. Allowing additional participants also increases market liquidity and creates a larger market.

Summary of Section 95814(a)(2)(A).

Subsection (a)(2)(A) proposes that an entity not identified as a covered entity or an opt-in covered entity could voluntarily register with the accounts administrator to become a Voluntary Associated Entity in order to acquire and hold California Compliance Instruments.

Rationale for Section 95814(a)(2)(A).

This provision is needed to allow additional participants interested in trading or voluntarily retiring compliance instruments to participate, increasing market liquidity and creating a larger market.

Summary of Section 95814(a)(2)(B).

Subsection (a)(2)(B) proposes that an entity operating an offset project could voluntarily register with the accounts administrator to become a Voluntary Associated Entity.

Rationale for Section 95814(a)(2)(B).

This provision is needed because before ARB can issue offset credits to the operator of an offset project registered with ARB, the operator must have a Holding Account into which ARB can transfer the offset credits.

Summary of Section 95814(b) through (b)(2), Other Registered Participants.

Subsections (b) through (b)(2) propose to allow entities that do not qualify to participate in the market or hold compliance instruments to register with the accounts administrator. These entities may include verifiers, verification bodies, Offset Project Registries, or other third parties approved pursuant to Subarticle 14.

Rationale for Section 95814(b) through (b)(2).

These provisions are necessary to ensure the integrity of the emissions verification and offset credit creation functions. The registration requirement gives ARB the opportunity to ensure that verifiers, verification bodies, and Offset Project Registries are qualified, free of conflicts of interest, and adhere to the provisions of this regulation. ARB can best ensure this by being able to use the

registration process to verify information on the entity, and to revoke registration (and prevent further participation) if the entity violates provisions of the regulation.

Summary of Section 95814(c).

Subsection (c) proposes that a registered entity that has had its Holding Account revoked pursuant to section 95831(b)(1) may not hold compliance instruments.

Rationale for Section 95814(c).

This provision is necessary because an entity may not participate in the cap-and-trade program if its Holding Account has been revoked due to a violation, to prevent further market disruption. ARB has an interest in protecting the integrity of the market.

Subarticle 4. Compliance Instruments.

Section 95820. Compliance Instruments Issued by Air Resources Board.

Summary of Section 95820(a), California Greenhouse Gas Emissions Allowances.

Subsection (a) identifies California Greenhouse Gas Emissions Allowances (CA GHG Allowances) as compliance instruments.

Rationale for Section 95820(a).

This provision is necessary so those participating in the program know which compliance instruments are valid.

Summary of Section 95820(a)(1).

Subsection (a)(1) proposes that CA GHG Allowances be issued by the Executive Officer. The amount of allowances issued by the Executive Officer will be equal to the schedule established in section 95841.

Rationale for Section 95820(a)(1).

This provision is necessary so those participating in the market know how many allowances will be in the market, which creates market stability.

Summary of Section 95820(a)(2).

Subsection (a)(2) proposes that each individual CA GHG Allowance issued by the Executive Officer be assigned a unique serial number that will also identify the year for which the allowance is issued.

Rationale for Section 95820(a)(2).

This provision is necessary so that each allowance is uniquely identifiable and cannot be used more than once. The serial numbers allow ARB to track the owner of the allowance at all times.

Summary of Section 95820(a)(3).

Subsection (a)(3) proposes that each CA GHG Allowance is placed into a Holding Account that is controlled by ARB.

Rationale for Section 95820(a)(3).

This provision is necessary because all allowances belong to ARB until they are put into the auction account or directly allocated to covered entities.

Summary of Section 95820(b), Offset Credits Issued by ARB.

Subsection (b) identifies offset credits issued by ARB as compliance instruments.

Rationale for Section 95820(b).

This provision is necessary so those participating in the program know which compliance instruments are valid.

Summary of Section 95820(b)(1).

Subsection (b)(1) proposes that the Executive Officer issue and register offset credits.

Rationale for Section 95820(b)(1).

This provision is necessary so that all offset credits used for compliance purposes meet the same requirements.

Summary of Section 95820(b)(2).

Subsection (b)(2) limits offset credits' use to the limit set forth in section 95855.

Rationale for Section 95820(b)(2).

This provision is necessary because users of offset credits need to know the use of offset credits is limited. For justification of section 95855, please see below.

Summary of Section 95820(c).

Subsection (c) proposes the properties associated with each compliance instrument, specifically that each compliance instrument represents permission to emit up to one metric ton of CO_2e. Additionally, the Executive Officer retains the right to revoke the authorization contained in the compliance instrument. Finally, compliance instruments do not constitute property or carry property rights.

Rationale for Section 95820(c).

This provision is necessary to inform holders of compliance instruments of the properties of compliance instruments. ARB has chosen to use a 1:1 ratio for compliance instruments to metric tons for administrative ease of calculation. Compliance instruments are created by ARB through AB 32, and are to be used solely for use as a compliance credit in California's market. It is necessary for the Executive Officer to retain authority to terminate or limit the "authorization to emit" so that in the case of fraud or market manipulation, ARB has a mechanism to protect the market. Additionally, property rights cannot attach to the compliance instruments because, in the event of federal preemption in the cap-and-trade market or other conditions, California must have the ability to revoke the compliance instruments without creating a loss to the people of California.

Section 95821. Compliance Instruments Issued by Approved Programs.

Summary of Section 95821(a) through (d).

Subsections (a) through (d) identify compliance instruments issued by other programs approved by ARB as compliance instruments that may be used to meet a compliance obligation.

Rationale for Section 95821(a) through (d).

These provisions are necessary so those participating in the program know which compliance instruments are valid. For justification of the specific requirements, please refer to those sections below.

Summary of Section 95821(e).

Subsection (e) identifies which compliance instruments issued by other approved programs are subject to the quantitative use limit.

Rationale for Section 95821(e).

This provision is necessary so those participating in the program know which compliance instruments issued by other approved programs are subject to the quantitative use limit. For justification of section 95855, please see above.

Subarticle 5. Registration and Accounts.

Section 95830. Registration with ARB.

Summary of Section 95830(a).

Subsection (a) proposes that the Executive Officer may serve as administrator of the accounts and tracking system or contract for the services.

Rationale for Section 95830(a).

This provision is necessary because ARB has not operated a tracking system of such complexity. ARB may find it is more efficient and less expensive to contract with a third party.

Summary of Section 95830(b).

Subsection (b) proposes that the Executive Officer must approve an entity's registration with ARB or that the entity is already registered with an external program approved by ARB before it can purchase or receive an allocation of allowances, buy offsets, or operate a project that will result in the creation of offsets.

Rationale for Section 95830(b).

This provision is necessary because ARB needs to maintain a complete record of all transactions involving California compliance instruments. To do this, ARB must know what entities are involved in any transaction. The registration requirement ensures anyone involved in transactions is subject to ARB requirements to report transactions.

Summary of Section 95830(c), Requirements for Registration.

Subsection (c) proposes that applicants for registration must submit information describing why they are participating in the system. They must also designate an authorized account representative, who will have the ability to make transactions and report them to ARB.

Rationale for Section 95830(c).

This provision is necessary because the applicant needs to identify how it qualifies for participation so ARB will know which rules to apply to the entity. Applicants also must identify any affiliated entities that are also participating in the system. This allows ARB to monitor transactions for potential collusion.

Summary of Section 95830(c)(1)(A).

Subsection (c)(1)(A) requires submission of an application for registration. The applicant must supply the name and a description of the organization registering.

Rationale for Section 95830(c)(1)(A).

The provision is necessary because ARB needs to collect basic information on registrants.

Summary of Section 95830(c)(1)(B).

Subsection (c)(1)(B) proposes that the applicant must identify how it qualifies to participate in the cap-and-trade system. The types of entities qualified to apply are identified in Subarticle 3.

Rationale for Section 95830(c)(1)(B).

The provision is necessary because Subarticle 3 identifies what types of entities may qualify to participate in the cap-and-trade system, as well as some that are prohibited from registering. Different rules apply to registrants depending on the category for which they are registering.

Summary of Section 95830(c)(1)(C).

Subsection (c)(1)(C) proposes that applicants must identify affiliated entities that are also registering.

Rationale for Section 95830(c)(1)(C).

The provision is necessary because identification of affiliates is needed for ARB to monitor the transactions in the market. An entity has a "direct corporate association" if it has a specified level of ownership or control over another entity. An entity has an "indirect corporate association" if it has a direct corporate association with a second entity, which in turn has a direct corporate association with a third entity.

Summary of Section 95830(c)(1)(D).

Subsection (c)(1)(D) proposes that applicants must disclose if they intend to hold compliance instruments which are actually owned by another entity.

Rationale for Section 95830(c)(1)(D).

The provision is necessary because ARB must be able to determine who is making the decisions on transactions in the market. ARB must also be able to evaluate a limit on how many compliance instruments an entity may control.

Summary of Section 95830(c)(1)(E).

Subsection (c)(1)(E) proposes that the Executive Officer may reject an application based on information contained in the application or withheld from the application.

Rationale for Section 95830(c)(1)(E).

The provision is necessary because ARB needs to ensure the integrity of the program and regulating participants contributes to that integrity. ARB may deny registration if it concludes the applicant does not qualify to participate. In addition, ARB may use information it collects from monitoring the market to determine if

the applicant has provided false or misleading information, or has withheld information. These are grounds for disqualifying an applicant.

Summary of Section 95830(c)(2).

Subsection (c)(2) proposes that an applicant must designate individuals who are authorized to act on the applicant's behalf to actually conduct transactions. Section 95832 contains the specific requirements for authorized account representatives.

Rationale for Section 95830(c)(2).

The provision is necessary because ARB needs a record of who may file transactions or information on behalf of the applicant for administrative purposes. ARB will reject transactions or information filed by anyone not designated as an authorized account representative.

Summary of Section 95830(d)(1).

Subsection (d)(1) proposes that entities qualifying as covered entities must register.

Rationale for Section 95830(d)(1).

The provision is necessary because ARB will need the registration information to administer the program.

Summary of Section 95830(d)(1)(A).

Subsection (d)(1)(A) proposes that an entity which becomes a covered entity after the cap-and-trade regulation is effective must register within 45 days of the deadline for reporting its emissions.

Rationale for Section 95830(d)(1)(A).

The provision is necessary to ensure the new covered entity registers promptly. ARB believes that 45 days will be sufficient for the entity to complete the registration process.

Summary of Section 95830(d)(1)(B).

Subsection (d)(1)(B) states that if an entity has crossed the 25,000 $MTCO_2e$ annual emissions threshold for any data year 2008 through 2010, it must register within 30 days of the effective date of this regulation.

Rationale for Section 95830(d)(1)(B).

The registration deadline provision is necessary for two reasons. First, based on the reporting deadlines in the Mandatory Reporting Regulation (MRR), it ensures

that an entity which becomes a covered entity will have enough time to complete registration by the proposed deadline. Second, the provision gives ARB enough time to process the registrations for the start of the program in 2012.

Summary of Section 95830(d)(2)(A).

Subsection (d)(2)(A) proposes that an entity must register by December 31, 2011, if it chooses to participate in the cap-and-trade system in 2012 as an opt-in participant, as allowed in section 95813.

Rationale for Section 95830(d)(2)(A).

The provision is necessary because Section 95813 allows an entity with reported emissions below the threshold to voluntarily subject itself to the compliance requirements of the cap-and-trade regulation. To be eligible to receive direct allocations of allowances, and to allow ARB to correctly calculate their compliance obligations in 2012, these entities must complete their registration before December 31, 2011. ARB believes this schedule gives the entity time to complete the registration process.

Summary of Section 95830(d)(2)(B).

Subsection (d)(2)(B) proposes that an entity choosing to participate as an opt-in participant, as allowed in section 95813, must register by November 30 of the year before which it chooses to participate in the cap-and-trade system.

Rationale for Section 95830(d)(2)(B).

The provision is necessary to allow ARB to correctly calculate an entity's compliance obligations and create the necessary accounts. ARB believes this schedule gives the entity time to complete the registration process.

Summary of Section 95830(d)(3).

Subsection (d)(3) proposes that an entity registering as a voluntarily associated entity or in the category of other market participant must complete registration prior to holding compliance instruments or fulfilling other functions such as verification. However, they do not face any other deadlines for registration.

Rationale for Section 95830(d)(3).

The provision is necessary because entities that do not have a compliance obligation must register before they perform any other functions within the cap-and-trade system, such as holding allowances or conducting transactions, operating offset projects, or performing verifications. ARB believes this schedule gives the entity time to complete the registration process.

Summary of Section 95830(e).

Subsection (e) proposes that the Executive Officer determines when the registration is complete, approves the registration, and informs both the applicant and the accounts administrator of the approval. The accounts administrator will then create the accounts relevant for the type of registration approved.

Rationale for Section 95830(e).

This provision is necessary because approval of registration is not automatic. ARB must review the applicant's information for accuracy, and then determine whether the applicant is eligible to participate. ARB may need to review reporting data and information contained in the application, as well as the applicant's history of participation in the system.

Section 95831. Account Types.

Summary of Section 95831(a)(1).

Subsection (a)(1) states that the Executive Officer will authorize only one set of accounts for an entity which has completed registration.

Rationale for Section 95831(a)(1).

This provision is needed to serve two purposes. First, it ensures that ARB can effectively monitor the holdings of registered entities. Second, it ensures that ARB can effectively discipline an entity that violates the regulations by suspending, restricting, or revoking the entity's account.

Summary of Section 95831(a)(2).

Subsection (a)(2) proposes that the Executive Officer will create a Holding Account for any entity that completes registration as a covered entity, opt-in covered entity, or a voluntarily associated entity.

Rationale for Section 95831(a)(2).

The provision is necessary because an entity will need a Holding Account to keep compliance instruments.

Summary of Section 95831(a)(3).

Subsection (a)(3) proposes that some covered entities that receive a direct allocation will be given a Limited Use Holding Account in addition to their Holding Account for holding their allowances.

Rationale for Section 95831(a)(3).

The provision is necessary because some covered entities in the electricity retail distribution sector will receive a direct allocation of allowances from ARB. However, the allocation comes with restrictions on what the covered entities can do with their allowances. The creation of these special accounts will allow ARB to enforce the restrictions efficiently.

Summary of Section 95831(a)(3)(A).

Subsection (a)(3)(A) proposes that an entity with a Limited Use Holding Account may not transfer instruments from a Holding Account into this account.

Rationale for Section 95831(a)(3)(A).

The provision is necessary because entities with a Limited Use Holding Account may sell the allowances at the consignment auction. The restriction on transfers into this account prevents the entity from selling other allowances at consignment.

Summary of Section 95831(a)(3)(B).

Subsection (a)(3)(B) proposes that allowances placed into the Limited Use Holding account may not be transferred to any account other than the Auction Holding Account under the control of the Executive Officer.

Rationale for Section 95831(a)(3)(B).

The provision is necessary because allowances allocated to Limited Use Holding account holders are intended to be used for the benefit of electricity ratepayers. ARB will ensure this by requiring the covered entities to auction the allowances through the consignment option and use the proceeds to reduce electricity costs for ratepayers.

Summary of Section 95831(a)(4).

Subsection (a)(4) proposes that the Executive Officer will create a Compliance Account for any entity that completes registration as a covered entity or opt-in covered entity.

Rationale for Section 95831(a)(4).

The provision is necessary because when an entity needs to surrender a compliance instrument, it will transfer the instrument from its Holding Account to its Compliance Account.

Summary of Section 95831(a)(4)(A).

Subsection (a)(4)(A) proposes that a covered entity may transfer compliance instruments to its Compliance Account at any time.

Rationale for Section 95831(a)(4)(A).

The provision is necessary because ARB sees no reason to restrict when a covered entity can transfer instruments to its Compliance Account. In addition, instruments placed in a Compliance Account do not count toward a covered entity's holding limit, which is described in section 95920.

Summary of Section 95831(a)(4)(B).

Subsection (a)(4)(B) proposes that when a covered entity transfers a compliance instrument into its Compliance Account it may not remove it later.

Rationale for Section 95831(a)(4)(B).

The provision is necessary because ARB is imposing this restriction as a method of giving a covered entity an exemption from the holding limit for compliance instruments it has accumulated to cover its surrender obligation. If ARB is going to give covered entities the exemption, the entities should not be able to transfer the instruments to another registered entity.

Summary of Section 95831(b)(1).

Subsection (b)(1) proposes that the Executive Officer may revoke or suspend the registration of a voluntarily associated entity for violations of the regulation.

Rationale for Section 95831(b)(1).

The provision is necessary because this option ensures that entities violating the regulation do not continue to disrupt the market.

Summary of Section 95831(b)(1)(A).

Subsection (b)(1)(A) proposes that if the Executive Officer revokes an entity's registration, the entity will be given thirty days to sell or voluntarily retire any compliance instruments in its Holding Account.

Rationale for Section 95831(b)(1)(A).

The provision is necessary because once an entity's registration is revoked or suspended, its Holding Account is revoked or suspended as well, and it can no longer hold compliance instruments. ARB believes thirty days should give an entity sufficient time to transfer its instruments before it can no longer access its account.

Summary of Section 95831(b)(1)(B).

Subsection (b)(1)(B) proposes that if an entity whose registration and Holding Account have been suspended does not sell or voluntarily retire the compliance instruments in its account, ARB will transfer the allowances to the consignment auction for sale and return the auction proceeds to the entity. Any remaining offsets will be retired by ARB.

Rationale for Section 95831(b)(1)(B).

The provision is necessary because ARB must have a method of dealing with an entity which refuses to remove compliance instruments from its holding account when its registration has been revoked or suspended. This approach ensures that the entity receives value for the allowances sold at auction. ARB has no comparable way to sell offsets, so the offsets will be retired and the account holder compensated through the consignment auction pursuant to section 95910(d)

Summary of Section 95831(b)(2)(A).

Subsection (b)(2)(A) proposes that the Holding Account of any entity may be restricted for violations of the regulation to hold a number of compliance instruments that is less than the holding limit.

Rationale for Section 95831(b)(2)(A).

The provision is necessary to allow ARB to restrict holdings below the usual holding limit, as a response to rule violations. Normally, an entity may hold as many compliance instruments as it wishes, up to a number set by the holding limit. Restricting the number of compliance instruments held may be the only remedy available to prevent violations. For example, ARB could not suspend or revoke the account of a covered entity, which needs the accounts for compliance purposes, but ARB could penalize the entity by removing some of the flexibility afforded to covered entities under the rules.

Summary of Section 95831(b)(2)(B).

Subsection (b)(2)(B) proposes that the Holding Account of any entity may be restricted for violations of the regulation to limit or prohibit transfers in or out of the account.

Rationale for Section 95831(b)(2)(B).

The provision is necessary to allow ARB to respond to rule violations by restricting an entity's ability to accumulate instruments or participate in market activity. These could be implemented by prohibiting further transfers into or out of the entity's account.

Summary of Section 95831(c), Accounts Under the Control of the Executive Officer.

Subsection (c) proposes that there will be several accounts under the control of the Executive Officer.

Rationale for Section 95831(c).

The provision is necessary to allow the Executive Officer to serve essential functions of the system, such as the creation or approval of compliance instruments, auction operation, direct allocations to entities, voluntary retirements, surrender compliance, and the maintenance of a list of compliance instruments that have been retired in the California system or a GHG emissions trading system (ETS) to which California has linked.

Summary of Section 95831(c)(1).

Subsection (c)(1) proposes that the Executive Officer will control the Allocation Holding Account, into which the serial numbers of allowances will be recorded when the allowances are created.

Rationale for Section 95831(c)(1).

The provision is necessary because the Executive Officer must be able to introduce new allowances into the system. Allowances and offset credits do not exist outside of the system of accounts. Allowances are created when they are assigned serial numbers and the numbers are placed in the Allocation Holding Account. This account will be the source account when the Executive Officer transfers them to some other account for direct allocation or for auction.

Summary of Section 95831(c)(2).

Subsection (c)(2) proposes that the Executive Officer will control the Auction Holding Account, into which the serial numbers of allowances will be transferred for sale at auction.

Rationale for Section 95831(c)(2).

The provision is necessary because the Executive Officer must be able to transfer allowances from several source accounts to a central account for auction.

Summary of Section 95831(c)(2)(A).

Subsection (c)(2)(A) proposes that the Allocation Holding Account will be the source of allowances allocated by ARB directly to auction.

Rationale for Section 95831(c)(2)(A).

The provision is necessary because in each budget year ARB will designate a number of newly created allowances to be auctioned. Before each quarterly auction, ARB will need to transfer allowances to the Auction Holding Account.

Summary of Section 95831(c)(2)(B).

Subsection (c)(2)(B) proposes that the Executive Officer may transfer allowances from accounts that are to be suspended or revoked.

Rationale for Section 95831(c)(2)(B).

The provision is necessary to allow allowances previously allocated or auctioned to registered entities to be transferred to the auction if the entities' registration and accounts are to be suspended or revoked. In those cases, if the entities do not transfer all compliance instruments out of the account, ARB will consign them for sale at the auction.

Summary of Section 95831(c)(2)(C).

Subsection (c)(2)(C) proposes that covered entities may transfer allowances from Limited Use Holding Accounts to the Auction Holding Account.

Rationale for Section 95831(c)(2)(C).

The provision is necessary to permit allowances previously allocated to covered entities to be transferred to the auction.

Summary of Section 95831(c)(3).

Subsection (c)(3) proposes that the Executive Officer will transfer instruments from individual Compliance Accounts to the Retirement Account when compliance deadlines occur. Individual account holders may also voluntarily retire allowances by transferring them from their Holding Accounts to the Retirement Account.

Rationale for Section 95831(c)(3).

The provision is necessary because the transfer of a compliance instrument to the Retirement Account is the way instruments will be removed permanently from the system.

Summary of Section 95831(c)(3)(A).

Subsection (c)(3)(A) proposes that an instrument transferred to the Retirement Account cannot be further transferred to any holding or Compliance Account.

Rationale for Section 95831(c)(3)(A).

The provision is necessary because any instrument transferred to the Retirement Account must be removed from the system, and no further transfers may be permitted.

Summary of Section 95831(c)(3)(B).

Subsection (c)(3)(B) proposes that If California retires an instrument, it would then inform any linked ETS that the retirement has occurred.

Rationale for Section 95831(c)(3)(B).

The provision is necessary to guarantee that any compliance instrument retired by California will not then be traded on any system to which California chooses to link.

Summary of Section 95831(c)(3)(C).

Subsection (c)(3)(C) proposes that once an instrument has been transferred to the Retirement Account, the Executive Officer will publish the retirement by recording the serial number of the retired instrument in a public registry.

Rationale for Section 95831(c)(3)(C).

The provision is necessary because placing the serial number in a public registry will ensure the public can observe that entities are complying with their surrender obligations and that retired instruments are no longer circulating.

Summary of Section 95831(c)(4)(A) through (c)(4)(D).

Subsections (c)(4)(A) through (c)(4)(D) propose that the Allowance Price Containment Reserve Account will be a Holding Account into which the Executive Officer will transfer allowances from several sources: allowances initially allocated for auction, but which remain unsold when an auction settles at the reserve price; allowances directly allocated to the Reserve; and allowances submitted in fulfillment of an excess emissions obligation.

Subsection (c)(4)(D) proposes that section 95913 contains the rules governing the operation of the Allowance Price Containment Reserve Account.

Rationale for Section 95831(c)(4)(A) through (c)(4)(D).

Subsections (c)(4)(A) through (c)(4)(D) are needed to define the three sources of allowances that fund the Allowance Price Containment Reserve Account.

The first source is allowances remaining unsold at auction. Allowances would be unsold when an auction is settled at the auction reserve price. This could occur if

allowances are temporarily oversupplied to the market. Placing the unsold allowances in the Reserve helps eliminate the temporary oversupply and makes the allowances available if prices are much higher in the future.

The second source is direct allocation of a large number of allowances from future vintages. ARB chose this method to create a reserve of sufficient size to provide credible cost containment.

The third source is allowances surrendered to meet an excess emissions obligation when entities fail to comply in a timely manner with surrender obligations. However, the excess emissions obligation could reduce supplies of allowances to the market. This could result in higher prices for all entities. Placing the allowances used to meet the excess emissions obligation into the Allowance Price Containment Reserve keeps the allowances available for purchase in times of high market prices.

Subsection (c)(4)(D) is necessary to define the process by which allowances are removed from the Allowance Price Containment Reserve Account. Allowances may be withdrawn from the Allowance Price Containment Reserve Account as a source of an additional supply of allowances, which covered entities may purchase during times of high prices. The rules governing these sales from the Reserve are contained in section 95913.

Summary of Section 95831(c)(5)(A).

Subsection (c)(5)(A) proposes that the Executive Officer will ensure that a percentage of the offsets issued by ARB for projects approved under the Compliance Offset Protocol for Forest Projects are placed in a Holding Account known as the *Forest Buffer Account.*

Rationale for Section 95831(c)(5)(A).

The provision is necessary because the Forest Buffer Account will be used to replace offset credits that are invalidated due to an unintentional reversal of a forest project. The Compliance Offset Protocol for Forest Projects contains a procedure to determine the proportion of the offset credits issued for a project that must be placed into the Reserve. The Executive Officer must ensure this transfer takes place so that the Reserve may contain enough offset credits to replace invalidated offset credits.

Summary of Section 95831(c)(5)(B).

Subsection (c)(5)(B) proposes that the Executive Officer will remove offset credits from the Forest Buffer Account when an unintentional reversal occurs. These offset credits will be transferred to the Retirement Account.

Rationale for Section 95831(c)(5)(B).

The provision is necessary because the Executive Officer will use offset credits in the Forest Buffer Account to ensure the integrity of the retirement process.

Summary of Section 95831(c)(6), Voluntary Renewable Energy Allowance Set-Aside Account.

Subsection (c)(6) is reserved for a possible future account for a voluntary renewable energy allowance set-aside.

Rationale for Section 95831(c)(6).

The cap-and-trade program could have negative effects on the voluntary renewable energy (VRE) market that could be addressed through a voluntary renewable energy allowance set-aside. The proposed regulation does not currently provide for allocation of voluntary renewable energy allowance set-aside, but leaves this subsection as a placeholder for establishing an account to use as part of such a provision in the future.

Section 95832. Designation of Authorized Account Representative.

Summary of Section 95832(a)(1) through (a)(5).

Subsections (a)(1) through (a)(5) require that every application for registration pursuant to 95830 must designate a single authorized account representative and a single alternate authorized account representative who may act on behalf of the authorized account representative.

Subsections (a)(1) through (a)(5) list the required elements for the application. These include names and addresses of individuals named as representatives; name of the organization applying; statements of beneficial ownership and relationships between beneficial owners; and a certification statement signed by the authorized representatives.

Rationale for Section 95832(a)(1) through (a)(5).

These provisions are necessary to identify the individuals authorized to transact on behalf of the account holder.

Summary of Section 95832(b).

Subsection (b) proposes that the Executive Officer, not the accounts administrator, has the responsibility to evaluate the documentation supporting authorizations.

Rationale for Section 95832(b).

The provision is necessary because the accounts administrator simply processes transactions under the direction of the Executive Officer. The Executive Officer has the sole responsibility to recognize authorized account representatives.

Summary of Section 95832(c)(1) through (c)(3).

Subsections (c)(1) through (c)(3) contain requirements for the accounts administrator to perform when a registration application is received. Subsection (c)(1) requires creation of the account for the registrant. Subsection (c)(2) requires the registering entity owning any instruments in the account be bound by any action of the authorized account representative or alternate authorized account representative. Subsection (c)(3) requires the registering entity owning any instruments in the account be bound by orders issued by a court or the Executive Officer to the authorized account representative or alternate authorized account representative.

Rationale for Section 95832(c)(1) through (c)(3).

These subsections are necessary so that the account holder owning any instruments in an account is bound by the actions of courts, the Executive Officer, or the authorized account representative or alternate authorized account representative.

Summary of Section 95832(d) and (e).

Subsection (d) and (e) propose the requirements for certifications that must accompany any submission concerning the account by the account holder. Section (e) requires the accounts administrator to accept submissions only if accompanied by the proper certification.

Rationale for Section 95832(d) and (e).

These provisions are essential to ensuring that transaction submissions are only made by the persons authorized to do so.

Summary of Section 95832(f)(1) through (f)(4).

Subsections (f)(1) through (f)(4) contain the rules for changing an authorized account representative or alternate authorized account representative or a change to the entities that own compliance instruments in an account.

Rationale for Section 95832(f)(1) through (f)(4).

These provisions are necessary so that the accounts administrator can properly process changes of the authorized account representative or alternate authorized account representative or a change to the entities that own compliance instruments in an account.

Summary of Section 95832(g)(1) through (g)(3).

Subsections (g)(1) through (g)(3) contain requirements for the processing of objections concerning the authorized account representative or alternate authorized account representative. The accounts administrator will recognize the representatives named in completed registration applications until new applications are completed.

Rationale for Section 95832(g)(1) through (g)(3).

These provisions are necessary to maintain the ability of the accounts administrator to recognize an authorized account representative or alternate authorized account representative and process transactions submitted until representatives are changed through the registration process. The accounts administrator will not be involved with objections or disputes, and will only deal with submissions from the representatives designated through the registration process.

Summary of Section 95832(h)(1) through (h)(5).

Subsections (h)(1) through (h)(5) contain a process that must be followed for the authorized account representative or alternate authorized account representative to delegate the authority to another person. These requirements include notice that must be provided to the accounts administrator; a certification statement; processing of the delegation and superseding delegations by the accounts administrator, and handling of electronic submissions.

Rationale for Section 95832(h)(1) through (h)(5).

These provisions are necessary in case the authorized account representative or alternate authorized account representative need to delegate their authority. The provisions ensure that the accounts administrator will always only recognize a single authorized account representative or alternate authorized account representative as being able to submit transactions concerning accounts.

Subarticle 6. California Greenhouse Gas Allowance Budgets.

Section 95840. Compliance Periods.

Summary of Section 95840.

This section proposes the three compliance periods. A compliance period represents a three-year window for which covered entities' greenhouse gas emissions will be summed to calculate a triennial compliance obligation. Covered entities must surrender an equivalent number of compliance instruments to match their compliance obligation for each three-year period.

Rationale for Section 95840.

This section is necessary to establish multiyear compliance periods, which enhance flexibility for covered entities and help smooth allowance price volatility related to variations in emissions levels due to changes in weather, market conditions, or other variables. However, very long compliance periods cannot provide regular assurance that emissions targets are being met and that covered entities are acquiring sufficient compliance instruments to match their obligations. Staff concluded that three-year compliance periods—with interim partial surrenders annually—will appropriately balance the goals of flexibility and environmental integrity. In reaching this conclusion, staff relied on the advice of the Market Advisory Committee, deliberations with Western Climate Initiative partners, and the example set by the Regional Greenhouse Gas Initiative.

Section 95841. Annual Allowance Budgets for Calendar Years 2012–2020.

Summary of Section 95841.

This section proposes the total amount of allowances that will be created for each year. These annual allowance budgets, when coupled with permissible offset credit usage, represent a set of annual emissions targets for the covered entities.

Rationale for Section 95841.

The allowance budgets begin with the expected level of emissions from the narrow scope covered sources in 2012 and expand in 2015 to account for coverage of additional sources. This framework was adopted to allow one year of program coverage prior to any required emissions reductions, to ensure a smooth transition as a category of covered entities enters the program.

The allowance budget levels were based on an analysis of historical, current, and projected future emissions levels relative to the 2020 economy-wide target set forth by AB 32. In developing these budgets, staff synthesized the results of multiple analyses of GHG abatement opportunities and costs for the covered entities. In addition, staff considered California Executive Order S-3-05 that requires an 80 percent reduction of GHGs from 1990 levels by 2050, input from WCI partner deliberations, targets in existing GHG cap-and-trade systems, proposed federal climate legislation, the work of the United Nations' Intergovernmental Panel on Climate Change, and stakeholder comment.

Subarticle 7. Compliance Requirements for Covered Entities.

Section 95850. General Requirements.

Summary of Section 95850(a), Reporting Requirements.

Subsection (a) proposes that covered entities be subject to ARB's Mandatory Reporting Regulation.

Rationale for Section 95850(a).

This provision is necessary because covered entities must first report so that ARB can determine if they should be classified as covered entities and if they exceed the emissions threshold. Also, a covered entity's compliance obligation is calculated based on its reported emissions.

Summary of Section 95850(b), Record Retention Requirements.

Subsection (b) proposes that emissions data reports should be kept for 10 consecutive years by each covered entity and they must provide them to ARB within 20 days of a request.

Rationale for Section 95850(b).

This provision is necessary to cover all three compliance periods and the following year of the last compliance period. Covered entities must give records within 20 days to give them sufficient time to collect the information without delaying ARB's review.

Summary of Section 95850(b)(1).

Subsection (b)(1) specifies that covered entities must retain data and provide it to ARB upon request.

Rationale for Section 95850(b)(1).

This provision is necessary to allow covered entities to know what documentation they need to retain and provide to ARB upon request.

Summary of Section 95850(b)(2).

Subsection (b)(2) specifies that covered entities must keep, and provide to ARB if requested, records that are used to calculate their compliance obligations.

Rationale for Section 95850(b)(2).

This provision is necessary for ARB to ensure that the compliance obligation is correctly calculated over time.

Summary of Section 95850(b)(3).

Subsection (b)(3) requires covered entities to keep, and provide to ARB if requested, their verification statements.

Rationale for Section 95850(b)(3).

This provision is necessary for ARB to ensure that the emissions data used for purposes of (b)(2) was verified by an ARB accredited verification body.

Section 95851. Phase-in of Compliance Obligation for Covered Entities.

Summary of Section 95851(a).

Subsection (a) provides which covered entities have a compliance obligation in the first compliance period beginning in 2012. These include: operators of facilities, first jurisdictional deliverers of electricity, and suppliers of CO_2 that exceed the emissions threshold.

Rationale for Section 95851(a).

This provision is included because not all covered entities have a compliance obligation beginning in the first compliance period, and other sectors are phased in later in the program. These emissions sources are regulated in the context of clean air regulations; therefore, it is practical to cover these sectors from the start of the program in 2012.

Summary of Section 95851(b).

Subsection (b) provides which covered entities have a compliance obligation in the second compliance period beginning in 2015. These emissions sources include: suppliers of natural gas, transportation fuels, and natural gas liquids that exceed the emissions threshold.

Rationale for Section 95851(b).

These emission sources are included beginning in 2015 because there are currently no reporting requirements in place for these sources. This additional time will give these sources enough time to collect and verify their emissions data and provide it to ARB.

Section 95852. Emissions Categories Used to Calculate Compliance Obligations.

Summary of Section 95852.

This section identifies how ARB will calculate and assign compliance obligations to entities in the case of positive or qualified positive verification statements and in the case that an entity does not submit an emissions data report or complete verification.

Rationale for Section 95852.

This section is included because entities must know in advance how their emissions data reports will ultimately be assigned a compliance obligation under these different scenarios.

Summary of Section 95852(a), Operators of Facilities.

Subsection (a) proposes which GHG emissions operators of facilities will hold a compliance obligation for. Operators of facilities have a compliance obligation for every metric ton of CO_2e of positive or qualified positive GHG emissions, either as a process emission or a stationary combustion emission.

Rationale for Section 95852 (a).

This provision is included because operators of facilities may combust both process and stationary emissions, each of which will be covered under this program. It is important to identify the emissions categories used to calculate compliance obligations for operators of facilities.

Summary of Section 95852(b), First Deliverers of Electricity.

Subsection (b) proposes that a first deliverer of electricity has a compliance obligation for every metric ton of CO_2e of positive or qualified positive GHG emissions, stationary combustion emissions, or emissions associated with electricity imported into California.

Rationale for Section 95852(b).

This provision is included because first deliverers of electricity may combust stationary emissions, or emissions associated with electricity, each of which will be covered under this program. It is important to identify the emissions categories used to calculate compliance obligations for first jurisdictional deliverers of electricity.

Summary of Section 95852(c), Suppliers of Natural Gas.

Subsection (c) proposes that a supplier of natural gas has a compliance obligation for every metric ton of CO_2e of GHG emissions that would result from full combustion or oxidation of all fuel delivered to end users in California, less the fuel that is delivered to other covered entities.

Rationale for Section 95852(c).

This provision is included because it is necessary to identify the emissions categories used to calculate compliance obligations for suppliers of natural gas.

Summary of Section 95852(d), Suppliers of RBOB and Distillate Fuel Oils.

Subsection (d) identifies that a supplier of petroleum products has a compliance obligation for every metric ton of CO_2e of GHG emissions that would result from full combustion or oxidation of the quantities of RBOB, Distillate Fuel Oil No. 1, and Distillate Fuel Oil No. 2.

Rationale for Section 95852 (d).

This provision is included because it is necessary to identify the emissions categories used to calculate compliance obligations for suppliers of petroleum products. It is necessary to identify the specific fuels in (d)(1), (d)(2) and (d)(3) to ensure there is no confusion about which fuels generate a compliance obligation.

Summary of Section 95852(e)(1), Producers of Natural Gas Liquids; Producers of Liquefied Petroleum Gas.

Subsection (e)(1) identifies that a producer of liquefied petroleum gas has a compliance obligation for every metric ton of CO_2e of GHG emissions that would result from full combustion or oxidation of all fuel sold, distributed, or otherwise transferred for consumption in California.

Rationale for Section 95852(e)(1).

This provision is included because it is necessary to identify the emissions categories used to calculate compliance obligations for producers of natural gas liquids.

Summary of Section 95852(e)(2), Producers of Natural Gas Liquids: Importer consignees of Liquefied Petroleum Gas.

Subsection (e)(2) identifies that an importer of liquefied petroleum gas has a compliance obligation for every MT of CO2e of GHG emissions that would result from full combustion or oxidation of all fuel imported into California.

Rationale for Section 95852(e)(2).

This provision is included because it is necessary to identify the emissions categories used to calculate compliance obligations for importers of natural gas liquids.

Summary of Section 95852(f), Suppliers of Blended Fuels.

Subsection (f) identifies suppliers of blended fuels as entities with compliance obligations under this regulation based on the constitution of the blended fuel.

Rationale for Section 95852(f).

This section is necessary to ensure that suppliers of blended fuels are aware that, even though the blended fuel itself may not have a compliance obligation under the regulation, the different parts of the blend are subject to the regulation and incur a compliance obligation if the parts of the blended fuel meet the requirements of the regulation.

Summary of Section 95852(g), Suppliers of Carbon Dioxide.

Subsection (g) identifies that a supplier of carbon dioxide has a compliance obligation for GHG emissions that would result from imported and exported quantities of carbon dioxide.

Rationale for Section 95852(g).

This provision is included because it is necessary to identify the emissions categories used to calculate compliance obligations for suppliers of carbon dioxide.

Summary of Section 95852(h).

Subsection (h) identifies that the compliance obligation is calculated from the CO_2, CH_4, and N_2O emissions from fossil fuel combustion, the CH_4 and N_2O emissions from all biomass-based fuel combustion, the CO_2 emissions from the combustion of unverifiable biomass-derived fuels listed in 95852.2, the CO_2 emissions from the combustion of biomass-derived fuels not listed in 95852.2, and the CO_2, CH_4, and N_2O from all process and fugitive emissions specified in the Mandatory Reporting Regulation, except those listed in 95852.2(a)(6)

Rationale for Section 95852(h).

This provision is included because CO_2e may or may not include biomass-derived fuel. The current U.S. EPA requirement for facilities reporting annual emissions of CO_2, CH_4, N_2O, and each fluorinated GHG includes annual biogenic CO_2 emissions as aggregated for all GHGs from all applicable source categories.

Section 95852.1. Compliance Obligations for Biomass-Derived Fuels.

Summary of Section 95852.1, Compliance Obligations for Biomass-Derived Fuels.

This section states that entities that have emissions from the combustion of biomass-derived fuels incur a compliance obligation for every metric ton of CO_2e emissions emitted from biomass-derived fuels.

Rationale for Section 95852.1.

This section is necessary to ensure that all possible emissions of CO_2e from fuel combustion incurs a compliance obligation.

Summary of Section 95852.1 (a).

Subsection (a) specifies that combustion emissions from source categories not listed under section 95852(g) do not hold a compliance obligation.

Rationale for Section 95852.1 (a).

This provision is included because entities whose aggregate emissions include biomass-derived fuels will not count those emissions toward their total compliance obligation when reporting.

Summary of Section 95852.1 (b).

Subsection (b) specifies emissions from source categories that are listed under 95852(g), but are not verifiable under MRR section 95131(i).

Rationale for Section 95852.1 (b).

This provision is included because some biomass-derived fuels may be verifiable, and others may be reported, but unverifiable.

Section 95852.2. Emissions Without a Compliance Obligation.

Summary of Section 95852.2, Emissions Without a Compliance Obligation.

This section identifies emissions from specific sources that count toward the reporting threshold for the Mandatory Reporting Regulation, but do not count toward a cap-and-trade compliance obligation threshold.

Rationale for Section 95852.2.

This section is included because emissions from specified sources are not required to hold a compliance obligation under AB 32; however, ARB maintains the need to collect the emissions data from these sources in the event that they are covered in the future. Emissions from specified source categories may be required to report, but will not hold a compliance obligation.

Summary of Section 95852.2 (a) through (e).

Subsections (a) through (e) propose facilities using biomass, municipal solid waste, geothermal, hydropower, or biodiesel are subject to the additional resource or fuel-specific requirements described here.

Rationale for Section 95852.2(a) through (e).

These provisions summarize the requirements for a facility, which qualify for the Renewables Portfolio Standard (RPS). These categories are excluded from holding a compliance obligation because these facilities are subject to a separate regulation regarding RPS.

Summary of Section 95852(f) Fugitive and Process Emissions.

Subsection (f) identifies fugitive emissions that do not hold a compliance obligation. These emissions include CO_2 emissions from geothermal generating units, CO_2 and CH_4 emissions from geothermal facilities, and CO_2 emissions

from hydrogen fuel cells. This includes emissions at petroleum refineries such as asphalt-blowing operations, equipment leaks, storage tanks, and loading operations and leak detection and leaker emission factors, and stationary fugitive and stationary vented sources on offshore oil platforms at petroleum and natural gas system facilities.

Rationale for Section 95852(f).

This provision is included because entities whose aggregate emissions include fugitive emissions from the activities described will not count those emissions toward their total compliance obligation when reporting.

Section 95852.3. Effect of Status Verification Statement on Calculation of Compliance Obligations.

Summary of Section 95852.3 (a).

Subsection (a) specifies that in the case of a positive or qualified positive verification statement, the compliance obligation will be calculated by using the reported and verified emissions, as outlined in section 95131 of the Mandatory Reporting Requirements.

Rationale for Section 95852.3 (a).

This provision is necessary to specify how different types of verification statements will be used to calculate a compliance obligation.

Summary of Section 95852.3 (b).

Subsection (b) specifies that in the case of an adverse verification statement, for every metric ton of CO_2e of GHG emissions, as determined by ARB, the compliance obligation will equal the ARB-assigned emissions, as outlined in section 95131 of the Mandatory Reporting Regulation.

Rationale for Section 95852.3 (b).

This provision is necessary to specify how different types of verification statements will be used to calculate a compliance obligation.

Summary of Section 95852.3 (c).

Subsection (c) specifies that in the case than an entity does not submit an emissions data report or complete verification, the EO will determine its compliance obligation, as set forth in section 95103 of the Mandatory Reporting Regulation.

Rationale for Section 95852.3 (c).

This provision is necessary to specify how different types of verification statements will be used to calculate a compliance obligation.

Section 95853. Calculation of Covered Entity's Triennial Compliance Obligation.

Summary of Section 95853(a)

This section states that any entity that exceeds the compliance threshold in any of the three years before the start of a compliance period is an entity covered by the regulation for the entire next compliance period. It further specifies that the entity's compliance obligation will be calculated based on the total verified emissions from the entire compliance period.

Rationale for Section 95853(a)

This section is necessary to ensure that all entities that may be covered entities pursuant to this regulation are aware of the conditions that would make an entity a covered entity. This section is also necessary to inform all covered entities of their ongoing compliance obligations even though the entity may not exceed the threshold in subsequent years.

Summary of Section 95853(b)

This section states that if a covered entity initially exceeds the threshold stated in the regulation during the first year of a compliance period, that entity is a covered entity for all three years of the compliance period. It further specifies that the entity's compliance obligation will be calculated based on the total verified emissions from the entire compliance period.

Rationale for Section 95853(b)

This section is necessary to inform an entity that had not previously been subject to the regulation and whose emissions exceed the threshold in the first year of a compliance period, that the entity remains a covered entity for the entire compliance period.

This section is also necessary to inform all covered entities of their ongoing compliance obligations even though the entity may not exceed the threshold in subsequent years.

Summary of Section 95853(c)

This section states that if a covered entity initially exceeds the emissions threshold during the second year of a compliance period, the entity is a covered entity for the second and third years of the compliance period only.

It further specifies that, for an entity that first exceeds the regulation threshold in the second year of a compliance period, the entity's compliance obligation will be calculated based on the total verified emissions from the second and third year of the compliance period.

Rationale for Section 95853(c)

This section is necessary to clarify when an entity that had not previously been subject to the regulation and whose emissions exceed the threshold in the second year of a compliance period becomes a covered entity under the regulation, and when the newly covered entity's compliance obligation begins.

Summary of Section 95853(d)

This section states that if a covered entity initially exceeds the emissions threshold during the third year of a compliance period, the entity has a compliance obligation for the third year of the compliance period only. The section also states that the compliance obligation for its emissions from the third year of the compliance period is not due until the subsequent compliance period. The covered entity's compliance obligation for the third year will be added to the subsequent compliance period obligations.

Rationale for Section 95853(d)

This section is necessary to clarify that the compliance obligation for an entity that becomes a covered entity during the third year of the compliance period is not due immediately. The section further clarifies that the compliance obligation is not forgiven, but, for purposes of ease of administration, the obligation is added to the subsequent compliance period's compliance obligations.

Summary of Section 95853(e)

Subsection (e) states that if a new covered entity is eligible to receive a direct allocation of allowances, it will not receive an allocation until the year following the first year the covered entity exceeds the threshold of this regulation. In that year, it will receive twice the number of allowances which it is eligible to receive for a single year.

Rationale for Section 95853(e)

This provision is necessary because the verified information needed to allocate allowances will not be available until the year following the first time the entity exceeds the threshold of this regulation.

Section 95854. Quantitative Usage Limit on Designated Compliance Instruments – Offset Credits.

Summary of Section 95854.

Section 95854 proposes that a covered entity may use compliance instruments identified in sections 95821(b), (c), and (d) to meet up to 8 percent of its annual or triennial compliance obligation. Compliance instruments identified in section 95821(d) may only be used to meet up to 25 percent of this 8 percent limit (i.e., a maximum of 2 percent) during the first and second compliance periods, and up to 50 percent of this 8 percent limit (i.e., a maximum of 4 percent) during the third compliance period.

Rationale for Section 95854.

This section is needed to identify which compliance instruments may be used to meet up to 8 percent of a covered entity's compliance obligation. The purpose of this is to create a limit on offsets to balance emissions reductions from covered entities and offset projects.

Section 95855. Annual Compliance Obligation.

Summary of Section 95855(a).

Subsection (a).states that a covered entity will incur an annual compliance obligation each year that it is a covered entity, except when the entity becomes a covered entity during a reporting data year. In that case the entity will not owe an annual obligation for that year.

Rationale for Section 95855(a).

This provision is needed to define when an entity will incur an annual compliance obligation. The entity will owe an annual compliance obligation for any year when it is a covered entity for the entire year.

ARB staff is proposing an annual compliance obligation primarily as a safeguard against defaults by emitters. With a three-year compliance period, an entity could run up a large amount of emissions before defaulting. This would leave ARB in the position of having to either make up for the defaulted emissions from another source of reduction or risk having emissions exceed the cap. ARB chose the three-year compliance period to give entities the flexibility to emit early and purchase allowances later in the period. Nonetheless, staff believes a prudent entity would accumulate at least some allowances, even if it chose such a strategy. A partial annual surrender obligation would thus not be a hardship.

This provision is needed because the annual compliance obligation is due in the middle of the year following the actual emissions. ARB was concerned that new covered entities may not have sufficient time to acquire allowances for the annual obligation. Waiving the first annual compliance obligation does not result in any "forgiveness" of emissions. Rather, the entity will simply have to cover the emissions at the end of the three-year compliance period.

Summary of Section 95855(b).

Subsection (b) defines the annual compliance obligation for a covered entity as 30 percent of the entity's reported and verified emissions from the previous year.

Rationale for Section 95855(b).

This provision is necessary because staff believes that setting the annual compliance obligation to 30 percent of an entity's emissions for the previous year will not pose a hardship for a prudent entity, even one that intends to purchase allowances late in the compliance period to cover its emissions. However, it may allow ARB to identify entities failing to meet the 30 percent requirement as risks for eventual default. Staff believes this approach balances the flexibility given to emitters through the three-year compliance period against the need to identify and prevent defaults.

Section 95856. Timely Surrender of Compliance Instruments by a Covered Entity.

Summary of Section 95856(a).

Subsection (a) requires that a covered entity must surrender one compliance instrument for each metric ton of GHG emissions (in CO_2 equivalent) contained in the entity's surrender obligation. Some of the instruments must be surrendered each year, while others are surrendered at the end of the three-year compliance period.

Rationale for Section 95856(a).

This provision is needed to clarify the basic compliance requirement for covered entities. They must turn in allowances or offset credits in amounts equal to their emissions during the compliance period. Covered entities will make a partial surrender each year and cover the remaining emissions at the end of the three-year compliance period.

Summary of Section 95856(b)(1).

Subsection (b)(1) identifies the California compliance instruments; instruments issued by GHG ETS to which California links, and offset credits that are valid for compliance.

Rationale for Section 95856(b)(1).

This provision is needed to clarify which instruments will be accepted by ARB for surrender compliance.

Summary of Section 95856(b)(2).

Subsection (b)(2) states that compliance instruments are issued for a specific allowance budget year, also known as a *vintage year.* With limited exceptions, a

compliance instrument must be issued for a vintage year within or before the year or years for which the obligation is calculated to be valid to meet a surrender obligation.

Rationale for Section 95856(b)(2).

This provision is needed because ARB will issue allowances for vintage years through 2020 at the beginning of the program. In some cases, such as allowances sold at the advance auction, allowances from future vintage years can be purchased and held, but not used for surrender.

The use of compliance instruments from future vintage years for current compliance is known as "borrowing." Staff is proposing to prohibit borrowing to avoid a scenario known as "cascading borrowing." If borrowing were allowed, the added supply would reduce current market prices for instruments. This would lead to a reduction in the level of direct emissions reductions, as well as a greater surrender of instruments compared with a scenario of no borrowing. In turn, this would lead to a smaller supply of instruments in future compliance periods, leading to an even greater reliance on borrowing. Ultimately, either the borrowing would lead to the cap being violated or covered entities having to make drastic reductions in a short period of time.

Summary of Section 95856(b)(2)(A).

Subsection (b)(2)(A) states that covered entities will be able to use future vintage allowances years if the allowances are purchased from the Allowance Price Containment Reserve.

Rationale for Section 95856(b)(2)(A).

This provision is necessary because ARB needed a source of allowances in order to fund a credible cost containment reserve. The only source was future vintage allowances, which would be useless as a cost-containment mechanism if they could not be used for compliance when purchased.

Summary of Section 95856(b)(2)(B).

Subsection (b)(2)(B) proposes that covered entities be able to use allowances from future vintages if the allowances are used to fulfill excess emissions obligations.

Rationale for Section 95856(b)(2)(B).

This provision is needed because excess emissions obligations would only be incurred in the year after the year for which a compliance obligation is calculated. There would not be time to accumulate a supply of instruments from the appropriate vintages. In addition, ARB staff wants to avoid having the excess

emissions obligations excessively tighten the market for instruments at the time of compliance deadlines.

Summary of Section 95856(c).

Subsection (c) states that in order to comply with a surrender obligation, a covered entity simply transfers the serial number of valid compliance instruments from its Holding Account to its Compliance Account by the compliance deadline.

Rationale for Section 95856(c).

This provision is needed to simplify the surrender process. The covered entity does not have to submit any documentation on its surrender other than filing a transactions report with the accounts administrator. These transactions are time-stamped and can only be made by the account holder's authorized account representative, so it will not be difficult to verify timely compliance.

Summary of Section 95856(d)(1).

Subsection (d)(1) requires that covered entities that report by April 1 under section 95103 of the MRR must complete their annual compliance obligation by May 15 of the following year.

Rationale for Section 95856(d)(1).

This provision is needed to inform a covered entity of the specific date by which all transfers of compliance instrument to its Compliance Account must be completed.

Summary of Section 95856(d)(2).

Subsection (d)(2) requires that covered entities that report by June 1 under section 95103 of the MRR must complete their annual compliance obligation by July 15 of the following year.

Rationale for Section 95856(d)(2).

This provision is needed to inform a covered entity of the specific date by which all transfers of compliance instrument to its Compliance Account must be completed.

Summary of Section 95856(e)(1).

Subsection (e)(1) states that the Executive Officer will determine the covered entity's triennial obligation compliance based on a review of the positive or qualified verifications statement for the third year of the compliance period.

Rationale for Section 95856(e)(1).

This provision is needed to allow the Executive Officer to review verifications reports and resolve any issues involving verification reports, so that the covered entity can complete timely transfers of compliance instrument to its Compliance Account.

Summary of Section 95856(e)(2).

Subsection (e)(2) states that in the absence of a positive or qualified verifications statement for the third year of the compliance period, the Executive Officer will determine the covered entity's triennial obligation assigning emissions, according to the requirements set forth in section 95130 of the MRR.

Rationale for Section 95856(e)(2).

This provision is needed to allow the Executive Officer to resolve any issues involving missing data or negative verification reports, so that the covered entity can complete timely transfers of compliance instrument to its Compliance Account.

Summary of Section 95856(e)(3).

Subsection (e)(3) states that the Executive Officer will issue a final determination of the covered entity's triennial compliance obligation following a data review and reconciliation process pursuant to section 95104 of the MRR.

Rationale for Section 95856(e)(3).

This provision is needed to allow the Executive Officer to resolve any issues involving missing or problematic data, so that the covered entity can complete timely transfers of compliance instruments to its Compliance Account.

Summary of Section 95856(f)(1).

Subsection (f)(1) requires that a covered entity must complete the transfer of compliance instruments to fulfill its triennial compliance obligation by November 1 of the calendar year following the third year of the compliance period.

Rationale for Section 95856(f)(1).

This provision is needed to inform a covered entity of the specific date by which all transfers of compliance instrument to its Compliance Account must be completed.

Summary of Section 95856(f)(2).

Subsection (f)(2) requires that the number of offset credits used to fulfill the combined annual and triennial surrender obligations is subject to the quantitative use limit on offset credits.

Rationale for Section 95856(f)(2).

This provision is needed to inform a covered entity of the maximum number of offset credits it is allowed to transfer to its Compliance Account to complete the triennial compliance obligation.

Summary of Section 95856(f)(3)

Subsection (f)(3) states that the triennial surrender obligation will account for compliance instruments already surrendered pursuant to the annual compliance obligation.

Rationale for Section 95856(f)(3)

This provision is necessary to clarify that the triennial surrender obligation will account for previously surrendered compliance documents so the covered entity will not be required to resubmit compliance instruments.

Summary of Section 95856(g)(1).

Subsection (g)(1) states that when the Executive Officer has determined that the covered entity has met a surrender obligation, the Executive Officer shall retire the compliance instruments surrendered.

Rationale for Section 95856(g)(1).

This provision is needed to ensure that surrendered instruments can never be used again in California.

Summary of Section 95856(g)(2).

Subsection (g)(2) states that when the Executive Officer has determined that the covered entity has met a surrender obligation, the Executive Officer shall inform programs to which California has linked or that California recognizes that the surrendered compliance instruments have been retired.

Rationale for Section 95856(g)(2).

This provision is needed to ensure that surrendered instruments can never be used again in programs California recognizes or to which California is linked.

Section 95857. Untimely Surrender of Compliance Instruments by a Covered Entity.

Summary of Section 95857(a)(1).

Subsection (a)(1) states that when a covered entity or opt-in covered entity that does not meet the compliance deadline for annual or triennial compliance is subject to the compliance obligation for excess emissions.

Rationale for Section 95857(a)(1).

This provision is needed to clarify when the excess emissions obligation applies.

Summary of Section 95857(a)(2).

Subsection (a)(2) states that when an entity that fails to meet its triennial or annual compliance obligation only because it submitted offset credits that were invalidated upon review by the Executive Officer will not incur an excess emissions obligation.

Rationale for Section 95857(a)(2).

This provision is needed because the Executive Officer may invalidate offset credits after they are issued. ARB staff believes it is possible that the entity submitting the offset credit for compliance may be unaware of the defect, and therefore should only have to replace the invalidated offset credit with a valid compliance instrument, and not face an excess emissions obligation.

Summary of Section 95857(b)(1).

Subsection (b)(1) defines the quantity of excess emissions as the difference between the compliance obligation and any compliance instruments surrendered by the compliance deadline by the covered entity.

Rationale for Section 95857(b)(1).

This provision is needed to define the calculation for excess emissions using two quantities known immediately after the compliance deadline.

Summary of Section 95857(b)(2).

Subsection (b)(2) defines the covered entity's compliance obligation for untimely surrender as four times the entity's excess emissions

Rationale for Section 95857(b)(2).

This provision is needed to provide the calculation for the excess emissions obligation using two quantities known immediately after the compliance deadline. ARB staff is proposing the excess emissions obligation to ensure that no covered entity would knowingly fail to meet its compliance obligations. ARB staff is proposing an in-kind obligation instead of a financial obligation, so that the obligation results in further environmental improvement.

Summary of Section 95857(b)(3).

Subsection (b)(3) states that a covered entity's compliance obligation for untimely surrender may only be fulfilled with allowances issued by California or by a GHG ETS to which California has linked.

Rationale for Section 95857(b)(3).

This provision is needed because ARB staff proposes to not allow the use of offset credits to satisfy the excess emissions obligation so that the obligation results in further environmental improvement.

Summary of Section 95857(c)(1).

Subsection (c)(1) states that an excess emissions obligation is immediately due.

Rationale for Section 95857(c)(1).

This provision is needed because having the obligation due immediately allows the Executive Officer to implement a procedure to obtain the required allowances if the covered entity continues to fail to meet its obligations.

Summary of Section 95857(c)(2).

Subsection (c)(2) states that immediately upon determining that a covered entity has excess emissions, the Executive Officer shall prevent any transfers of compliance instruments from the Holding Account controlled by the covered entity.

Rationale for Section 95857(c)(2).

This provision is needed to prevent entities intending to default on their obligations from transferring instruments from their accounts.

Summary of Section 95857(c)(3).

Subsection (c)(3) states that the Executive Officer shall transfer any remaining allowances from the Holding Account controlled by the covered entity with excess emissions to its Compliance Account until the retirement obligations of this section are met.

Rationale for Section 95857(c)(3).

This provision is needed to give the Executive Officer authority to withdraw compliance instruments from a Holding Account of an entity that has not met its compliance obligations.

Summary of Section 95857(c)(4).

Subsection (c)(4) states that a if the Executive Officer is unable to withdraw sufficient allowances from an entity's Holding Account, the Executive Officer shall

provide the deficient covered entity 30 days to secure the allowances needed to cover its untimely surrender obligation.

Rationale for Section 95857(c)(4).

This provision is needed because ARB staff believes a covered entity would need time to acquire compliance instruments to meet its excess emissions obligations.

Summary of Section 95857(c)(5).

Subsection (c)(5) details a procedure to recover compliance instruments from a covered entity which defaults on its obligations.

Rationale for Section 95857(c)(5).

This provision is needed because ARB must anticipate cases, however unlikely, in which a defaulting entity takes steps to shield compliance instruments from retirement.

Summary of Section 95857(c)(5)(A).

Subsection (c)(5)(A) allows the Executive Officer to identify Holding Accounts controlled by affiliates of the deficient covered entity, to which the covered entity has transferred compliance instruments during the compliance period for which a compliance obligation remains unfilled.

Rationale for Section 95857(c)(5)(A).

This provision is needed to allow the Executive Officer to attempt to recover compliance instruments that should have been surrendered.

Summary of Section 95857(c)(5)(B).

Subsection (c)(5)(B) allows the Executive Officer to prevent transfers from the Holding Accounts belonging to entities with a corporate association to the deficient entity to which a deficient covered entity has transferred allowances, and retrieve allowances from those accounts to meet the untimely surrender obligation.

Rationale for Section 95857(c)(5)(B).

This provision is included to allow the Executive Officer to attempt to recover compliance instruments which should have been surrendered.

Summary of Section 95857(c)(6).

Subsection (c)(6) states that if the covered entity does not surrender sufficient allowances equal to its untimely surrender obligation by the end of the 30-day

period, the Executive Officer may undertake enforcement activities pursuant to Subarticle 15.

Rationale for Section 95857(c)(6).

This provision is needed so that ARB may use additional enforcement measures in case a covered entity does not comply with its untimely surrender obligation following the 30-day period.

Summary of Section 95857(d).

Subsection (d) details the activities the Executive Officer will undertake when the covered entity has complied with its untimely surrender obligations.

Rationale for Section 95857(d).

This provision is needed because there are standard activities that the Executive Officer must undertake after the covered entity has complied with its untimely surrender obligations.

Summary of Section 95857(d)(1).

Subsection (d)(1) requires the Executive Officer to remove the restrictions on transfers from the Holding Accounts controlled by the covered entity and affiliated entities.

Rationale for Section 95857(d)(1).

This provision is needed because once the untimely compliance obligation has been satisfied, there is no further need for the account restrictions.

Summary of Section 95857(d)(2).

Subsection (d)(2) states that the Executive Officer must perform the usual post-surrender activities of retiring the surrendered compliance instruments and informing the programs and GHG ETS to which California is linked of the retirements.

Rationale for Section 95857(d)(2).

This provision is needed because once the untimely compliance obligation has been rectified, the retirement process is the same as for timely compliance.

Summary of Section 95857(d)(3).

Subsection (d)(3) states that the Executive Officer must transfer the allowances used to fulfill the untimely surrender obligation to the Price Containment Reserve.

Rationale for Section 95857(d)(3).

This provision is needed because ARB staff is proposing this feature so that the fulfillment of the untimely surrender obligation does not overly reduce the supply of compliance instruments, and consequently raise their price. Placing these instruments in the Reserve will make them available at the Reserve release prices.

Subarticle 8. Disposition of Allowances.

Section 95870. Disposition of Allowances.

Summary of Section 95870, Disposition of Allowances

Section 95870 specifies how the total number of allowances available from each allowance budget will be divided. Each allowance is dedicated to one of the following categories: Allowance Price Containment Reserve, Advance Auction, Allocation to Electrical Distribution Utilities, Allocation to Industrial Covered Entities, or Auction Proceeds for AB 32 Statutory Objectives.

Summary of Section 95870.

This section is necessary to divide the value embodied by the tradable allowances among various AB 32 purposes. The first two categories—Allowance Price Containment Reserve and Advance Auction—enhance the operation of the allowance market by containing allowance price and providing a long-term signal about expected future prices. Dedicating allowances to electrical distribution utilities protects ratepayers from the costs of AB 32 programs. Distributing allowances to industrial covered entities helps to maintain the competitiveness of California industry and minimizes the risk of emissions leakage. Allocating allowances for the purpose of auction allows the Legislature to use auction proceeds for AB 32 purposes and protects fuel customers from the costs of AB 32 programs.

Summary of Section 95870(a). Allowance Price Containment Reserve.

Subsection (a) proposes to allocate allowances to the Allowance Price Containment Reserve. One percent of the allowances from the first compliance period will be allocated to the price containment reserve. Four percent of the allowances from the second compliance period will be allocated to the price containment reserve. Seven percent of the allowances from the third compliance period will be allocated to the price containment reserve.

Rationale for Section 95870(a).

The price containment reserve is expected to assist in maintaining allowance prices within a specific price range. The desired range was determined through the economic analysis of the cap-and-trade program, consideration of similar proposals in federal climate policy, and feedback from stakeholders.

The amount of allowances dedicated to the Reserve was selected based on an understanding of what size of reserve was necessary to provide the desired price containment. The level of allowances placed in the Reserve was matched with an introduction of additional offsets due to an expansion of the quantitative offset limit (relative to the level proposed in the Preliminary Draft Regulation). Placing a greater percentage of allowances to the Reserve from later periods enhances surety of price containment goals in the early years of the program.

Summary of Section 95870(b). Advance Auction.

Subsection (b) proposes to designate 2 percent of allowances from budget years 2015 through 2020 for auction in prior compliance periods. Selling allowances from future compliance periods in the current period is known as *advance auctioning.* Subsection (b)(2) proposes that proceeds from the sale of allowances from future budget years be used in the same way as proceeds from other allowances auctioned pursuant to subsection 95870(e).

Rationale for Section 95870(b).

Auctioning allowances from future budget years in a current compliance period provides a price signal to the market about expectation of future prices. This is valuable for covered entities planning long-term investments in GHG abatement. Staff determined that advance auctioning 2 percent of the budgets from the second and third compliance periods ensured that enough allowances will be available for other purposes in these later years, while still allowing for a future price signal to be established.

AB 32 requires that all proceeds raised through programs enacted under the authority of AB 32 be placed into the Air Pollution Control Fund for appropriation by the Legislature (HSC 38597). Therefore, proceeds raised through advance auction will be placed into this fund.

Summary of Section 95870(c). Allocation to Public Utilities.

Subsection (c) describes how allowances will be given to public utilities. It includes allowances allocated to electrical distribution utilities and natural gas distribution utilities.

Rationale for Section 95870(c).

Free allocation of allowances to public utilities on behalf of their customers is designed to help offset the cost impacts of AB 32 policies. This is described in more detail for each type of utility below.

Summary of Section 95870(c)(1). Electrical Distribution Utilities.

Subsection (c)(1) describes how allowances will be given to electrical distribution utilities on behalf of the ratepayers in their distribution service territory. The

utilities will receive a total of 89 million allowances from budget year 2012, and this amount will decline at the rate established for the cap decline factor in subsequent years through 2020. These allowances will be placed into the accounts of distribution utilities annually.

Rationale for Section 95870(c)(1).

Free allocation of allowances to electrical distribution utilities on behalf of their customers (ratepayers) is designed to help offset the cost impacts of AB 32 policies. The initial allocation to distribution utilities was selected by comparing the historical proportionate share of emissions produced from electricity (generated and placed on California's transmission and distribution network) relative to total emissions covered in the cap-and-trade program. In making this calculation, staff used 2008 emissions shares to determine the percentage for the 2012–2014 budget years. This value was then adjusted downward consistent with the cap decline factor, which is set consistent with the rate of decline of the overall cap during the first compliance period.

Summary of Section 95870(c)(2). Natural Gas Distribution Utilities.

Subsection (c)(2) is reserved for any possible future allocation to natural gas distribution utilities on behalf of their customers.

Rationale of Section 95870(c)(2).

The natural gas utilities have requested allowances on behalf of their customers. The proposed regulation does not currently provide for allocation to natural gas distribution utilities but leaves this subsection as a placeholder for such a provision in the future.

Summary of Section 95870(d). Allocation to Industrial Covered Entities.

Subsection (d) proposes to allocate allowances to industrial sectors for the purposes of industry assistance. The allowances will be transferred annually to each eligible covered entity's Holding Account. The amount of allowances that each eligible industrial sector receives will be based on the assistance factors, as provided in Table 8-1 of Regulation. Subsection (d)(3) ensures that the total amount allocated to the Allowance Price Containment Reserve, advance auction, electrical distribution utilities, and to industrial covered entities does not exceed the total allowance budget levels.

Rationale for Section 95870(d).

Industry assistance is necessary to provide a smooth transition into the cap-and-trade program for industrial covered sources that face a competitiveness risk. The level of assistance allocated will decline over time to a minimum level necessary to prevent emissions leakage as industrial sources adapt to carbon constraints. To align with federal mandatory reporting requirements for product

output reporting, allocation to industrial covered entities is based on an annual cycle. The table included in this section reflects ARB's assessment of industry needs to ensure that covered entities can plan for future compliance obligations.

Summary of Section 95870(e), Allocation to Voluntary Renewable Energy Allowance Set-Aside.

Subsection (e) is reserved for any possible future allocation to a voluntary renewable energy allowance set-aside.

Rationale for Section 95870(e).

The cap-and-trade program could have negative effects on the voluntary renewable energy (VRE) market that could be addressed through a voluntary renewable energy allowance set-aside. The proposed regulation does not currently provide for allocation of voluntary renewable energy allowance set-aside, but leaves this subsection as a placeholder for such a provision in the future.

Summary of Section 95870(f). Auction Proceeds for AB 32 Statutory Objectives.

Subsection (e) describes how the remaining allowances will be sold at auction, and how the proceeds will be placed in the Air Pollution Control Fund and made available for appropriation by the California Legislature. The Legislature will then direct how these proceeds will be used to protect fuel consumers and accomplish the statutory objectives of AB 32.

Rationale for Section 95870(f).

AB 32 requires that all proceeds raised through programs enacted under the authority of AB 32 be placed into the Air Pollution Control Fund for appropriation by the Legislature (HSC 38597).

Subarticle 9. Direct Allocations of California GHG Allowances.

Section 95890. General Provisions for Direct Allocations.

Summary of Section 95890. General Provisions for Direct Allocations.

Section 95890 specifies the requirements that entities must meet to be eligible for free allowances. This requirement includes complying with the MRR and obtaining a positive or qualified positive verification statement.

Rationale for Section 95890.

This section is necessary because the amount of allowances that a covered entity receives annually must be based on verified output data reported through the MRR process. Verified data ensures the level of free allowances that a

covered entity receives is accurate and has been checked by an ARB accredited verifier.

Section 95891. Allocation for Industry Assistance.

Summary of Section 95891(a).

Subsection (a) explains how ARB will determine which benchmarking methodology will be used to calculate the number of free allowances that each leakage-exposed industrial covered entity will receive. For entities that are listed in both tables 8-1 and 9-1 of the Regulation, the benchmarking methodology will be based on product output. For entities that are listed in Table 8-1 but not in Table 9-1 the benchmarking methodology will be based on energy consumption. Entities that are not listed in Table 8-1 will not receive free allocation under this provision.

Rationale for Section 95891(a).

Product-based benchmarks set an allocation level based on a unit of output. Staff proposes to apply product-based allocation as the preferred methodology to provide transition assistance and prevent leakage. This section is necessary because product-based allocation creates all of the correct incentives to produce a given product in the most GHG-efficient way possible and to minimize leakage.

For industrial activities with a competitiveness or leakage risk for which a product-based allocation cannot be developed, staff proposes a "fallback" allocation methodology based on benchmarking energy consumption choices.

Summary of Section 95891(b), Product Output-Based Allocation Calculation Methodology.

Subsection (b) proposes a formula to calculate the number of allowances given to each eligible covered entity based on the product output-based benchmarking methodology. The number of allowances for each eligible, covered entity will be determined by multiplying a facility's output by the sector-wide emissions efficiency benchmark specified in Table 9-1. A facility's output is based on the three most recently reported data years. The allocation is then adjusted by the sector-wide assistance factor specified in Table 8-1, and the sector-specific cap adjustment factor specified in Table 9-2 of the Regulation.

Rationale for Section 95891(b).

This provision is necessary to calculate how many allowances each eligible covered entity will be given for industry transition assistance and leakage prevention and to provide certainty to covered entities.

Summary of Section 95891(c), Thermal Energy-Based Allocation Calculation Methodology.

Subsection (c) proposes a formula to calculate the number of allowances given to each eligible covered entity based on benchmarking of energy consumption practices. The number of allowances for each eligible covered entity will be determined by multiplying the sector-specific assistance factor specified in Table 8-1 of the Regulation by the program-wide cap adjustment factor specified in Table 9-2, and an energy consumption term. The energy consumption term is dependent on the uses of fuel and steam at a given facility during the 2000–2010 historical baseline period.

Rationale for Section 95891(c).

This provision is necessary to calculate how many allowances each eligible, covered entity will be given for industry assistance using the energy-based allocation. The energy-based allocation is used because the only alternative is to calculate the allocation based on specifics of each facility or develop a product-based allocation for all industry, which is not feasible at this time.

Staff proposes that entities should receive either direct or indirect allocations to reduce GHG costs for energy consumed in a leakage-exposed manufacturing process. Energy embodied in steam consumed in the process and energy from direct fire applications receives a direct allocation through the thermal energy formula. Energy for electricity produced and consumed on-site also receives a direct allocation to offset direct GHG costs in the manufacturing process.

Thermal energy used to produce steam and electricity exported off-site receives no compensation because staff assumes that GHG costs can be passed on to the consumer of this energy.

Electricity purchased from off-site is not part of the thermal energy-based allocation equation but receives indirect compensation through distribution utility to offset the expected indirect GHG costs, as described in Section 95892.

The thermal energy consumed from the fuel combustion benchmark is based on GHG emissions levels from natural gas combustion, the dominant fuel used in California manufacturing facilities.

For energy embodied in the steam consumed by each facility, the benchmark is based on comparison to a theoretical boiler combusting natural gas with an assumed efficiency of 85 percent. This is intended to represent a highly efficient industrial boiler.

Summary of Section 95891(c)(1), Data Sources.

Subsection (c)(1) indicates the data sources that staff proposes ARB employ when calculating baseline levels of allocation to covered entities under the thermal energy-based methodology.

Rationale for Section 95891(c)(1).

Staff proposes that establishing the facility baselines under the thermal energy-based allocation method would employ data reported to ARB under the MRR. Any data that can be third-party verified and reported to ARB for the 2000–2010 base period will be evaluated by the Executive Officer. Staff proposes supplementing these data with an analysis of third-party verified data reported to the California Climate Action Registry (CCAR) for years 2000–2007 as available. These data sources have been chosen because staff believes that the third-party verified data reports submitted to ARB and CCAR represent the most accurate data for California facilities currently available.

Summary of Section 95891(c)(2), Maximum Free Allocation.

Subsection (c)(2) establishes an absolute limit on the level of free allocation under the thermal energy-based allocation relative to historical GHG emissions levels from a given facility. This limit is set at 110 percent of the maximum annual emissions during the baseline period.

Rationale for Section 95891(c)(2).

The thermal energy-based allocation is intended to reward facilities that have taken early action and chosen low-GHG fuels and/or employed efficient steam-generation systems. This reward occurs through allocating free allowances greater than expected compliance obligation to these facilities. This section is necessary to prevent the level of this reward from becoming excessive, and is constrained by other desired uses of allowance value. Staff proposes that the 110 percent of maximum historical emissions levels is sufficient reward to recognize early action and to ensure that early actors who have already taken on reductions equal to that required by the decline in allowance budgets over the 2012–2020 period are buffered from the impact of the declining (cap adjustment factor) term.

Summary of Section 95891(c)(3), New Entrants.

Subsection (c)(3) describes how covered entities for eligible industrial facilities new to the cap-and-trade program will receive allowances under the thermal energy-based allocation.

Rationale for Section 95891(c)(3).

The thermal energy-based allocation relies on information from a historical base period. To the extent that facilities did not operate or exist during this base period, the Executive Officer will need to assign a baseline level of allocation based on anticipated energy use to allocate allowances to these facilities.

Summary of Section 95891(c)(4), Facility Closures.

Subsection (c)(4) clarifies that covered entities will not continue to receive free allocation for any facilities that close or are no longer covered by the cap-and-trade program.

Rationale for Section 95891(c)(4).

Staff believes that continuing free allocation to covered entities that cease activities in California would create an incentive for leakage. Therefore, firms that close operations in California will no longer receive free allocations.

Firms that fall below the emissions inclusion thresholds due to GHG abatement can voluntary choose to remain in the cap-and-trade program as opt-in covered entities and continued to receive free allocation.

Section 95892. Allocation to Electrical Distribution Utilities for Protection of Electricity Ratepayers.

Summary of Section 95892(a).

Subsection (a) is reserved for the formula by which electrical distribution utilities will receive allowances on behalf of their ratepayers.

Rationale for Section 95892(a).

The allocation formula for distribution of allowances to electrical distribution utilities must further the cap-and-trade emissions-reduction objectives, including providing incentives to reduce emissions cost-effectively. Additionally, the allocation must enable all the utilities to serve their customers reliably and affordably. Details of the formula will be developed based on comments received during the 45-day comment period on the proposed regulation, and will be circulated for review in a subsequent 15-day comment period.

Summary of Section 95892(b). Transfer to Utility Accounts.

Subsection (b) explains that investor-owned utilities (electrical corporations) will receive free allocation into a special type of account called a Limited Use Holding Account. Publicly owned utilities will have the option to have allocations distributed to their limited use Holding Accounts or to their Compliance Accounts.

Rationale for Section 95892(b).

Distribution utilities that plan to monetize allowances on behalf of their ratepayers will receive a free allocation into limited use Holding Accounts. All allowances given to investor-owned utilities are required to be monetized. The publicly owned utilities have more flexibility. The transactions of allowances to and from limited use Holding Accounts will have special restrictions in the market tracking system.

Summary of Section 95892(c), Monetization Requirement.

Subsection (c) requires that distribution utilities offer each freely allocated allowance placed into a limited-use Holding Account at auction at least once in the calendar year corresponding to the budget year from which that allowance was issued.

If an allowance is not sold in the calendar year corresponding to the allowance's budget year (i.e., if the auction reserve price is not met for that allowance) the retail provider must offer this allowance at auction at least once in each of the following calendar years until it is sold.

Rationale for Section 95892(c).

Monetization of allowances through auction is intended to ensure that the amount of value given to distribution utilities is transparent to the public, and that this value is used on behalf of electricity ratepayers. This practice will also ensure that freely allocated allowances to a distribution utility will not impact competition in the electricity generation market (where utilities compete with merchant power producers).

This condition on allocating allowance value to distribution utilities was recommended to ARB by the California Public Utilities Commission and the California Energy Commission.

Summary of Section 95892(d), Limitations on the Use of Auction Proceeds.

Subsection (d) establishes limitations on how a distribution utility can use proceeds raised from the sale of allowances at auction.

Rationale for Section 95892(d).

These limitations ensure that allowance value given to a distribution utility will be used on behalf of ratepayers and in ways that are consistent with AB 32 statutory objectives.

Summary of Section 95892(d)(1) and 95892(d)(2).

Subsections (d)(1) and (d)(2) clarify that distribution utility proceeds from the sale of allowances at auction will be subject to limitations imposed by either the California Public Utilities Commission or by the governing bodies of publicly owned utilities.

Rationale for Section 95892(d)(1) and 95892(d)(2).

Proceeds from sale at allowances at auction will generate a new revenue stream for a distribution utility. This revenue stream will need to be accounted for along

with all other revenues and costs in the ratemaking actions of the CPUC and the governing bodies of the POUs.

Summary of Section 95892(d)(3).

Subsection (d)(3) clarifies that the statutory goals of AB 32 apply to all utility proceeds raised through auctioned allowances and that all proceeds must be used to the benefit of ratepayers rather than for the benefit of shareholders (or any other entities). Further limitations are placed on how rebates directly to customers must function.

Rationale for Section 95892(d)(3).

Limiting the use of proceeds on behalf of ratepayers and for the purposes of AB 32 ensures that distribution utility adopt programs that support GHG reductions and minimize cost of these programs to their customers.

Limiting customer rebates such that they appear on the fixed portion of customer bills and cannot be based solely on the amount of electricity consumed in any period after 2012 is intended to create an incentive to use less electricity and create a GHG price signal in retail electric rates.

Summary of Section 95892(e), Reporting on the Use of Auction Proceeds.

Subsection (e) requires that distribution utilities report to ARB on how they use proceeds generated from the sale of allowances at auction.

Rationale for Section 95892(e).

This provision will ensure transparency on how distribution utilities use allowance value and demonstrate that this value is used for the purposes of AB 32 implementation.

Section 95893. Reserved for Allocation to Natural Gas Distribution Utilities for Protection of Natural Gas Ratepayers.

Summary of Section 95893.

Section 95893 is reserved for the details of any possible future allocation method to individual natural gas distribution utilities on behalf of their customers.

Rationale for Section 95893.

The natural gas utilities have requested allowances on behalf of their customers. The proposed regulation does not currently allow for allocation to natural gas distribution utilities but leaves this section as a placeholder for such a provision in the future.

Subarticle 10. Auction and Sale of California Greenhouse Gas Allowances.

Section 95910. Timing of Auction of California GHG Allowances.

Summary of Section 95910(a), Timing of Allowance Auctions.

Subsection (a) sets a quarterly schedule for auctions.

Rationale for Section 95910(a).

The provision is needed because ARB must inform potential auction participants of the schedule for the quarterly auctions. ARB chose a quarterly auction to balance the costs of running auctions against the need to have a frequent price signal to the market.

Summary of Section 95910(a)(1).

Subsection (a)(1) states that the first auction will take place on February 14, 2012.

Rationale for Section 95910(a)(1).

The provision is needed because ARB must inform potential auction participants of the schedule for the quarterly auctions. This schedule places an auction close to the beginning of the program. Some stakeholders indicated they intend to purchase allowances as they emit, so ARB must get a supply into the market at the beginning of the program.

Summary of Section 95910(a)(2).

Subsection (a)(2) states that after the first auction, quarterly auctions will take place on the twelfth business day of the first month of each calendar quarter.

Rationale for Section 95910(a)(2).

The provision is needed because ARB must inform potential auction participants of the schedule for the quarterly auctions.

Summary of Section 95910(b).

Subsection (b) states that ARB may auction allowances created for future allowance budget years during each auction.

Rationale for Section 95910(b).

The provision is needed because ARB will allow entities to purchase allowances from future budget years to allow them to plan their purchases over a longer time horizon. However, they will not be able to use these allowances for compliance prior to their vintage year.

Summary of Section 95910(c)(1).

Subsection (c)(1) states that ARB will auction one-fourth of the allowances designated for auction each year at each quarterly auction.

Rationale for Section 95910(c)(1).

The provision is needed because ARB believes spreading the auction of allowances evenly through the year will provide for a more predictable entry of new supply to the market. This should allow for easier planning of allowances purchases by auction participants.

Summary of Section 95910(c)(2).

Subsection (c)(2) states that ARB will auction one-fourth of the allowances from future budget years, which are designated for auction each calendar year, at each quarterly auction.

Rationale for Section 95910(c)(2).

The provision is needed because ARB believes spreading the auction of allowances evenly through the year will provide for a more predictable entry of new supply to the market. This should allow for easier planning of allowances purchases by auction participants.

Summary of Section 95910(c)(3).

Subsection (c)(3) states that ARB will conduct separate auctions for current and future vintage allowances during each quarter.

Rationale for Section 95910(c)(3).

The provision is needed because auctions must be conducted separately, as future vintage allowances cannot be used for current compliance. ARB expects that separate auctions would result in different prices for current and future vintage allowances because the auction price of future vintage allowances will reflect bidders' evaluation of future prices and the added interest costs of buying and holding allowances that cannot be used for compliance right away.

Summary of Section 95910(d)(1).

Subsection (d)(1) states that ARB will not just auction allowances from its annual allowance budget. ARB will allow electrical distribution utilities to have ARB auction some allowances held by the entities, in what is known as a *consignment* auction. Only an entity with Limited Use Holding Account may use the consignment feature.

Rationale for Section 95910(d)(1).

The provision is needed because ARB has identified instances in which electrical distribution utilities should be allowed to sell allowances through ARB's auction. ARB intends to directly allocate allowances to the electrical distribution utilities for the benefit of their ratepayers. ARB chose the consignment auction feature to ensure that proceeds from the sale of the allowances benefit the ratepayers. ARB will assign the electrical distribution utilities Limited Use Holding Accounts to receive direct allocations of allowances from ARB. Once allowances are in the Limited Use Holding Account, the electrical distribution utilities may only consign them to the auction and cannot use them for any other purpose.

Summary of Section 95910(d)(2).

Subsection (d)(2) states that pursuant to 95831, ARB may close or revoke a Holding Account due to rule violations or a lack of activity by an entity. In these cases ARB will give the entity time to sell or retire the allowances in the account. If the entity does not do this, ARB will consign the allowances to the auction and then close the account. If the account contains offset credits, then the Executive Officer will review the validity of the offset credits. If they are valid, the Executive Officer will retire them, withdraw the same number of allowances from the Auction Holding Account, and consign them to the next auction in place of the offset credits.

Rationale for Section 95910(d)(2).

The provision is needed because if an entity is no longer participating in the system, its account must be closed. ARB must be able to transfer any remaining allowances to another account. The only method available is to consign them to the auction. This is straightforward for allowances, but ARB will not be auctioning offset credits. If offset credits are withdrawn from a closed account, the Executive Officer will determine if they are valid. If they are not, they will immediately be invalidated and their serial numbers removed from the tracking system. The account holder will receive no payment for them. If the review shows the offset credits are valid, they will be retired and the Executive Officer will withdraw the same number of allowances from the Auction Holding Account and consign them to the auction in place of the offset credits.

Summary of Section 95910(d)(3).

Subsection (d)(3) states that anyone using the consignment option agrees to accept the auction settlement price.

Rationale for Section 95910(d)(3).

The provision is needed because auction results are uncertain. Those entities using the consignment auction must commit to the auction before they know the auction settlement price.

Summary of Section 95910(d)(4).

Subsection (d)(4) states that entities must have consigned allowances at least 60 days before the auction date for them to be sold at the next auction. Otherwise, ARB will hold the consigned allowances for the next auction.

Rationale for Section 95910(d)(4).

The provision is needed because ARB must have time to complete the administrative procedures for the consignment auction before the auction takes place, including publishing the number of allowances that will be sold at the next auction.

Section 95911. Format for Auction of California GHG Allowances.

Summary of Section 95911(a)(1).

Subsection (a)(1) requires a single-round auction.

Rationale for Section 95911(a)(1).

The provision is needed because ARB staff determined that a single-round format would reduce costs to auction participants and to ARB, compared with a multiple-round auction format.

Summary of Section 95911(a)(2).

Subsection (a)(2) requires auction participants to submit sealed bids.

Rationale for Section 95911(a)(2).

The provision is needed to reduce the chances for collusion among auction participants. Other sections in this subarticle contain rules designed to prevent participants from sharing information that could result in collusion.

Summary of Section 95911(a)(3).

Subsection (a)(3) requires auction participants to submit bids for allowances in multiples of 1,000 metric tons.

Rationale for Section 95911(a)(3).

The provision is needed to simplify the auction process. Covered entities face a minimum threshold of 25,000 tons. Even with a minimum quantity of 1,000 tons per bid the smallest covered entity could spread out its purchases over a large number of auctions or bid prices.

Summary of Section 95911(a)(4).

Subsection (a)(4) requires auction participants to submit bids in whole dollars and whole cents.

Rationale for Section 95911(a)(4).

The provision is needed to simplify bidding and auction operations.

Summary of Section 95911(b)(1) and (b)(2).

Subsections (b)(1) and (b)(2) set a reserve price for each auction. The auction operator will not accept bids below the reserve price. No allowances can be awarded to bids below the reserve price.

Rationale for Section 95911(b)(1) and (b)(2).

These provisions are needed because staff determined that a reserve price, which is a minimum price for an auction, should be used for the auction. The reserve price will be announced prior to the deadline for submitting bids.

Most auctions use a reserve price. There are many reasons for using a reserve price. First, someone auctioning a good may have another way to sell or use the item. They would not accept an auction price for less than the value they could get from an alternative use or method of sale. Second, auction operators may use a reserve price to deter collusion. Collusion can occur if bidders are capable of communicating with other bidders and agreeing to submit low bids. The reserve price limits how far collusion could drive down prices. Third, in the case of GHG allowances, ARB may choose to use a reserve price to incent direct reductions by compliance entities or to support investment in offset projects. If allowances are abundant and there is no reserve price, it may be cheaper for covered entities to purchase allowances and not make any direct reductions. A reserve price would create an incentive for covered entities to find direct reductions that cost less than the reserve price. Similarly, if allowances are overabundant then they may cost less than what it would cost to operate a project to create offset credits. ARB could determine a price at which investment in some offset projects would be cost-effective.

ARB proposes an auction reserve price to provide a price floor to support investment in direct reductions and offset credit projects. ARB's cost containment approach requires the steady production of offset credits. If these do not materialize the Allowance Price Containment Reserve will not provide price stability because market participants will realize that the diversion of future vintage allowances to the Allowance Price Containment Reserve will result in a shortage of allowances in later compliance periods. ARB has also observed that a prolonged period of low allowance prices in the Northeast Regional Greenhouse Gas Initiative (RGGI) market has not supported incentives for the creation of offset credits.

Summary of Section 95911(b)(3).

Subsection (b)(3) describes how the auction operator will award allowances when an auction settlement price equals the minimum reserve price.

Rationale for Section 95911(b)(3).

The provision is needed because when the settlement price equals the reserve price there will be allowances left over. Since the allowances at any given auction may come from several sources, ARB needs to determine in what order allowances will be sold from each source.

Summary of Section 95911(b)(3)(A).

Subsection (b)(3)(A) lists the sources of allowances that are auctioned. When the auction results in some allowances left over, the auction operator will sell allowances from one source until all the allowances from that source are sold. The operator will then move on to the next source. The sales will be conducted from sources in the following order: allowances consigned from closed, revoked, or suspended accounts; allowances consigned from Limited Use Holding Accounts; and finally, allowances allocated directly to auction by ARB.

Rationale for Section 95911(b)(3)(A).

The provision is needed because ARB may need to return unsold allowances to their source accounts. Since this is not possible for allowances from closed, suspended, or revoked accounts, this source is given the first sales priority. The next sources are those entities consigning allowances. ARB intends to give these sources the next sales priority to simplify the consignment process. The lowest priority source is the ARB Auction Holding Account. ARB assigns this the lowest priority because it is easy for ARB to redirect the unsold allowances from this source to the Allowance Price Containment Reserve.

Summary of Section 95911(b)(3)(B).

Subsection (b)(3)(B) states that if the auction operator fills all winning bids before exhausting all allowances from one of the consigned sources, the auction operator will sell an equal number of allowances from each consigning entity in that source category.

Rationale for Section 95911(b)(3)(B).

The provision is needed because as the auction operator sells from one of the consignment source categories described above, it may fill all winning bids before every allowance from that source is sold. In this case, the auction operator will sell an equal number of allowances from each entity in that consignment category.

Summary of Section 95911(b)(4).

Subsection (b)(4) states that allowances designated by ARB for a quarterly auction which remain unsold will be transferred to the highest price tier of the Allowance Price Containment Reserve Holding Account.

Rationale for Section 95911(b)(4).

The provision is needed because allowances transferred from the Allocation Holding Account to the Auction Holding Account will not go back to the Allocation Holding Account if they remain unsold. Instead, ARB will transfer them to the Allowance Price Containment Reserve Holding Account. Once in that account, they may be purchased by covered entities pursuant to 95913. Allowances will remain unsold during times of oversupply and lower prices. ARB considered holding them over until the next auction, but that simply continues the oversupply. Placing them in the Reserve will make them available during periods of shortage and higher prices. ARB proposes to place them in the highest price tier because it is possible that all of the allowances in the lower tiers may be sold, at which point ARB will close those tiers to further sales. .

Summary of Section 95911(b)(5)(A).

Subsection (b)(5)(A) states that allowances consigned to auction from Limited Use Holding Accounts that remain unsold at auction will be returned to their source accounts.

Rationale for Section 95911(b)(5)(A).

The provision is needed if the auction settlement price equals the Reserve Price, then some allowances remain unsold. ARB must return them to the accounts from which they were consigned. This allows the account holders to determine when is the best time to consign the allowances.

Summary of Section 95911(b)(5)(B).

Subsection (b)(5)(B) states that allowances removed from closed Holding Accounts that remain unsold at auction will be held in the Auction Holding Account until the next auction.

Rationale for Section 95911(b)(5)(B).

The provision is needed because once a Holding Account is closed, allowances cannot be transferred back to it. The only option for allowances transferred from a closed account to the auction is to retain the allowances in the Auction Holding Account until they are sold, and the proceeds sent on to the entity with the closed account.

Summary of Section 95911(b)(6)(A).

Subsection (b)(6)(A) states that for auctions conducted during 2012, the auction Reserve Price shall be $10 for the auction of allowances from the 2012 allowance budget year, and $11.58 for the auction of allowances from the 2015 allowance budget year.

Rationale for Section 95911(b)(6)(A).

Staff proposes a $10 initial reserve price for auctions beginning in 2012 to provide incentives for direct emissions reductions and the investment in offset credit projects. The reserve price for the advance auction will start at $11.58 to reflect the rate at which the reserve price will increase each year. (Subsection 95911(b)(6)(B) explains how staff determined the inflator mechanism.)

Staff chose the $10 reserve price for two reasons. First, staff are concerned that through recessionary economic conditions or forecasting error the cap-setting procedure may accidently lead to the creation of excess allowances. Throughout the regulatory process, staff heard concerns from environmental groups that the cap would be unintentionally set too lax—a condition sometimes referred to as *oversupply* or *over-allocation.* The over-allocation condition occurs if too many allowances are supplied to covered entities relative to expected business-as-usual emissions levels. If the cap is set too loose, prices will be lower than expected, and a weakened incentive to reduce emissions will be created. The reserve price mechanism would correct this condition by transferring excess allowances to the Allowance Price Containment Reserve, where they will be available in times of high prices.

Second, staff is adapting the approach used in the federal Waxman-Markey proposal (HR 2454), which proposed a reserve price of $10 with an inflator mechanism of 5 percent per year plus inflation.

Summary of Section 95911(b)(6)(B).

Subsection (b)(6)(B) states that for auctions conducted after 2012, the auction reserve prices for the current and advance auctions from the previous year will each be increased by 5 percent plus the Consumer Price Index for All Urban Consumers.

Rationale for Section 95911(b)(6)(B).

Staff proposes an inflator mechanism based on the expectation that marginal abatement costs and offset project costs will increase over time as lower cost-abatement measures are undertaken first, and due to inflation. Auction reserve prices would need to increase to reflect the increased marginal abatement cost and the inflation rate; otherwise, the reserve price would no longer support direct reductions and offset projects as intended.

ARB's staff economic analysis assumed a rate of increase in marginal abatement costs of 7 percent, without factoring in inflation. Staff proposes to increase the reserve price by 5 percent, plus inflation each year, so that the reserve price continues to support direct reductions and offset investment as those become more expensive. At the same time, the reserve price will rise more slowly than the expected marginal abatement cost so that the reserve price does not make the program unnecessarily more expensive.

Summary of Section 95911(c).

Subsection (c) states that ARB will limit the share of the allowances at an auction that can be purchased by an entity or group of entities that has a corporate association under section 95914 to a fixed percentage. The limit will apply from 2012 through 2014.

Rationale for Section 95911(c).

The provision is needed because ARB has determined that a purchase limit should apply at each auction, to ensure that a few entities do not obtain market power through purchases at the auctions. Purchase limits are common features at existing auctions. For example, RGGI applies a 25 percent purchase limit to its auctions of GHG allowances.

ARB is proposing the limit for the first compliance period and will set the limit for subsequent periods in a later rulemaking. ARB is proposing this approach for three reasons. First, ARB will have a better understanding of the compliance needs of larger entities when new reporting data become available for the expanded scope of the program during the second compliance period. Second, ARB recognizes that the market will take time to develop, and it may be necessary to revise the limit based on actual market experience. Third, ARB intends to link with WCI jurisdictions at some point, but WCI has not arrived at a decision on purchase limits. ARB may have to revise the limit to account for the size distribution of covered entities in the WCI.

Summary of Section 95911(c)(1).

Subsection (c)(1) states that the purchase limit will be 10 percent for covered entities and opt-in covered entities.

Rationale for Section 95911(c)(1).

The provision is needed to base the purchase limit on an assessment of the holding limit and limited exemption for the larger covered entities in California. The holding limit with the limited exemption, contained in 95920, would constrain the largest covered entities in California to about 10 percent of the allowances issued annually. The purchase limit constrains them to purchase no more than the same share at auction. Staff believes this level will allow them to purchase sufficient allowances at auction given the direct allocations planned for the first compliance period. Smaller entities will have more flexibility.

Summary of Section 95911(c)(2).

Subsection (c)(2) states that the purchase limit will not apply to electrical corporations receiving a direct allocation of allowances which they may only consign to auction. The section may not be interpreted to exempt the entities

from any other requirements, especially the holding limit contained in Subarticle 11.

Rationale for Section 95911(c)(2).

This provision is needed due to the complexity of evaluating the compliance obligations of electrical corporations which import large amounts of electricity. ARB proposes to exempt these entities for three reasons. First, the only way to accommodate their compliance needs would be to raise the purchase limit to a point at which the limit has no effect on any entity. Second, these entities do not receive an allocation of allowances that they can use for their own compliance needs. They must purchase their entire obligation at auction or in the secondary market. Other covered entities participating in the auction do not face this constraint. Third, these entities are also regulated by the California Public Utilities Commission. The exemption from the purchase limit does not exempt them from other requirements of this regulation.

Summary of Section 95911(c)(3).

Subsection (c)(3) states that the purchase limit will be 4 percent for voluntarily associated entities.

Rationale for Section 95911(c)(3).

The provision is needed to base the purchase limit on an assessment of the holding limit without the limited exemption. Voluntarily associated entities do not qualify for the exemption. Based on current estimates of the 2012 allowance budget, the holding limit will allow voluntarily associated entities to hold about 4 percent of the annual allowance budget. The purchase limit allows them to purchase at auction in the same proportion

Summary of Section 95911(d).

Subsection (d) states that the auction process will generate a single, or "uniform," auction settlement price. All entities winning allowances will pay the same price for them.

Rationale for Section 95911(d).

The provision is needed to use a single price auction format instead of a "pay-as-bid" format. Staff concluded that the uniform price format would make it easier for bidders to bid their true valuation of the allowances with less risk of overpaying for allowances.

Summary of Section 95911(d)(1).

Subsection (d)(1) states that each bid will consist of a price and the number of allowances to be purchased at that price. The quantity must be in multiples of 1,000 metric tons.

Rationale for Section 95911(d)(1).

The provision is needed to conduct a single-round, uniform price auction. The requirement that bid quantities be in units of 1,000 allowances was chosen to simplify the auction process. Since covered entities would have obligations greater than 25,000 metric tons per year, staff concluded that the requirement would not prevent them from being able to spread out their purchases over a large number of separate bids.

Summary of Section 95911(d)(2).

Subsection (d)(2) states that each bidder may submit multiple bids.

Rationale for Section 95911(d)(2).

The provision is needed because bidders may use multiple bids to attempt to get most of their allowances when prices are low. Allowing multiple bids means that bidders can speculate on what the settlement price may be, while still ensuring they can purchase at least some allowances. For example, an entity may place one high bid because it has decided it needs at least that number of allowances at no more than a particular price. It may then place one or more bids at much lower prices, perhaps even below the price the entity expects, just in case the auction settles at an unusually low price. The only constraints on the bids are the purchase limit and the value of the bids compared to the value of the bid guarantee the bidder is willing to supply.

Summary of Section 95911(d)(3).

Subsection (d)(3) states that the auction operator will place the bids in declining order, from highest to lowest bid price.

Rationale for Section 95911(d)(3).

The provision is needed because placing the bids in declining price order allows the auction operator to determine whether the bids meet various auction rules. The auction operator will apply the rules to an entity's highest bid first, then proceeds to lower bids. This procedure will preserve an entity's more competitive bids if the auction administrator does not accept all the entity's bids.

Summary of Section 95911(d)(3)(A).

Subsection (d)(3)(A) states that the auction operator will not accept a bid if acceptance of the bid would violate the purchase limit.

Rationale for Section 95911(d)(3)(A).

The provision is needed because the action operator will evaluate the cumulative bids submitted by an entity against the purchase limits for individual or associated entities as appropriate. If a bid would result in an entity exceeding a limit, the auction operator will not accept it. If a bid is not accepted, the bid is disqualified. It will not be used to determine winning bids or the auction settlement price.

Summary of Section 95911(d)(3)(B).

Subsection (d)(3)(B) states that the auction operator will not accept a bid if acceptance of the bid would violate the holding limit.

Rationale for Section 95911(d)(3)(B).

The provision is needed because the action operator will evaluate the cumulative bids submitted by an entity against the holding limits for individual or associated entities as appropriate. If a bid would result in an entity exceeding a limit, the auction operator will not accept it. If a bid is not accepted, the bid is disqualified. It will not be used to determine winning bids or the auction settlement price.

Summary of Section 95911(d)(3)(C).

Subsection (d)(3)(C) states that the auction operator will not accept a bid if acceptance of the bid would result in the total value of the accepted bids exceeding the value of the bid guarantee submitted by the entity.

Rationale for Section 95911(d)(3)(C).

The provision is needed because the auction operator will calculate the value of a bid as the bid price times the quantity. The auction operator will add the value of each bid submitted by the entity in declining price order until all of the entity's bids have been counted or the cumulative value of the bids becomes greater than the value of the bid guarantee submitted by the entity. The auction operator will disqualify a bid that causes the cumulative value of bids to exceed the bid guarantee.

Summary of Section 95911(d)(4).

Subsection (d)(4) states that the auction operator will award allowances beginning with the highest bid and proceeding in declining bid price order.

Rationale for Section 95911(d)(4).

The provision is needed to implement the uniform price auction. While most bidders do not generally pay their bid price in a uniform price auction, bidding

high helps ensure that the bidder wins allowances. Allowances are awarded to the bids in declining price order until the auction operator meets a stopping point.

Summary of Section 95911(d)(4)(A).

Subsection (d)(4)(A) states that the auction operator will stop awarding allowances when the next lower bid price is less than the auction reserve price. At that point the auction operator declares the last winning bid as the auction settlement price.

Rationale for Section 95911(d)(4)(A).

The provision is needed because the auction operator cannot sell allowances below the reserve price. The auction operator must then set the auction settlement price equal to the reserve price. All winning bidders will pay the auction settlement price.

Summary of Section 95911(d)(4)(B).

Subsection (d)(4)(B) states what will happen if the quantity of allowance bids at the next lower bid price is greater than the number of allowances left to award. In this case the auction operator declares that price to be the auction settlement price, and will apply the tie-breaking procedure in 95911(d)(5).

Rationale for Section 95911(d)(4)(B).

The provision is needed because the auction operator sets the settlement price at the level that will exhaust all bids. In this case, there remain more bids than unawarded allowances. The auction operator must begin the tie-breaking procedure to award the last remaining allowances.

Summary of Section 95911(d)(5)(A).

Subsection (d)(5)(A) states that the auction operator may have to deal with instances in which there are more bids than allowances left. The auction operator will use a random number generator to assign a number to each bundle of 1,000 allowances contained in each bid submitted at the auction settlement price.

Rationale for Section 95911(d)(5)(A).

The provision is needed because when the auction settles at a price higher than the reserve price, the auction operator may not have enough allowances to fill all the bids submitted at the settlement price. ARB staff proposes a modification of the tie bid resolution process used by RGGI to break ties. In the RGGI procedure, a random number is assigned to each bid submitted at the settlement price, regardless of the quantity bid. Beginning with the lowest random number and proceeding to the highest, the auction operator awards allowances until all

are awarded. The last bidder winning allowances may get only part of the allowances for which it bid. The RGGI process treats each bidder equally, but could result in a situation in which one entity could win a disproportionate share of the remaining allowances.

Staff decided to modify the RGGI procedure by assigning a random number to each 1,000 metric ton bundle in each participant's bid. The auction operator would use random numbers to award allowances as in the existing RGGI procedure. However, in the staff proposal, one random number would be assigned to each of the 1,000 metric ton bundles for which an entity bids, instead of assigning one random number for the entire quantity bid. For example, in the RGGI approach someone bidding for 10,000 metric tons would receive one random number. In the staff proposal, the entity would receive ten random numbers.

ARB also considered prorating the allowances among the tied bidders. However, this might result in awards of allowances in bundles of less than 1,000 metric tons, which would add to the auction's complexity.

Summary of Section 95911(d)(5)(B).

Subsection (d)(5)(B) states that having assigned a random number to each bundle of 1,000 allowances contained in each tied bid, the auction operator will begin awarding allowances to the bidder with the lowest number. The auction operator will award allowances to the holder of the next lowest random number until all allowances are awarded.

Rationale for Section 95911(d)(5)(B).

The provision is needed because this approach will treat each tied bidder equally while reducing the chance that a bidder could win a disproportionate share of the remaining allowances.

Section 95912. Auction Administration and Registration

Summary of Section 95912(a).

Subsection (a) states that the Executive Officer may serve as auction administrator or designate an entity to serve as auction administrator.

Rationale for Section 95912(a).

This provision is needed to give ARB the flexibility to contract with an outside auction operator.

Summary of Section 95912(b).

Subsection (b) states that if California links with other jurisdictions' cap-and-trade systems, then California may participate in a joint allowance auction with those jurisdictions, provided the joint auction rules conform to the proposed regulation.

Rationale for Section 95912(b).

The provision is needed because California may link with cap-and-trade systems in other U.S. or Canadian jurisdictions in order to form a regional market. A regional market would operate more efficiently if the member jurisdictions jointly auctioned their allowances. However, California could only participate in a joint auction if the rules of that auctioned conformed with rules in this regulation.

Summary of Section 95912(c).

Subsection (c) states that an entity that intends to participate in an auction must complete an auction registration at least 30 days prior to the auction.

Rationale for Section 95912(c).

The provision is needed because ARB is requiring a separate auction registration, even though all participants are already registered account holders, for several reasons. First, it ensures the participants provide updated information. Second, the applications will inform the auction operator of the number of participants to expect. Third, the application will include agreement by the entity with the rules of the auction and any procedures set out by the auction operator.

Summary of Section 95912(c)(1).

Subsection (c)(1) states that the auction operator will publish a notice describing the auction and auction registration process at least 60 days before each auction.

Rationale for Section 95912(c)(1).

The provision is needed because auction participants must have sufficient time to prepare the auction application.

Summary of Section 95912(c)(2).

Subsection (c)(2) explains the information auction participants must submit with their auction applications.

Rationale for Section 95912(c)(2).

The provision is needed because the auction operator must collect information on auction participants in order to correctly evaluate purchase and holding limits, assess the financial capability of participants to execute bids, and conduct oversight of the auction.

Summary of Section 95912(c)(2)(A).

Subsection (c)(2)(A) states that the auction applicant must supply information and documentation on corporate identity, ownership, and capital structure.

Rationale for Section 95912(c)(2)(A).

The provision is needed because the auction operator must have correct information on the identity of bidders.

Summary of Section 95912(c)(2)(B).

Subsection (c)(2)(B) states that the auction applicant must supply information and documentation on corporate associations, as described in section 95914.

Rationale for Section 95912(c)(2)(B).

The provision is needed because the auction operator must have correct information on corporate associations in order to correctly apply the holding limit to purchases by bidders that are affiliated through a corporate association.

Summary of Section 95912(c)(2)(C).

Subsection (c)(2)(C) states that the auction applicant must supply information on beneficial holdings that may result from auction purchases or may already exist. The information must disclose the existence of associations with any other auction bidders.

Rationale for Section 95912(c)(2)(C).

The provision is needed because the auction operator must have correct information in order to understand relationships between auction participants. One type of association is between bidders. The auction operator must know of these arrangements in order to correctly apply purchase and holding limits. The calculation of both of these limits takes into account when one entity is holding or purchasing allowances on behalf of another. This is known as a *beneficial* holding. Ultimately, ARB must be aware of these relationships to perform effective market monitoring.

Summary of Section 95912(c)(2)(D).

Subsection (c)(2)(D) states that the auction applicant must supply information on any criminal history of officials of the bidding entity.

Rationale for Section 95912(c)(2)(D).

The provision is needed because the Executive Officer must be able to determine whether the applicant should be allowed to participate in the auction.

Summary of Section 95912(c)(2)(E).

Subsection (c)(2)(E) states that the auction applicant must supply information on previous or pending investigations of allegations that the bidding entity or its officials were involved in violations of rules, regulations, or law associated with any commodity market or exchange.

Rationale for Section 95912(c)(2)(E).

The provision is needed because the Executive Officer must be able to determine whether the applicant should be allowed to participate in the auction.

Summary of Section 95912(c)(2)(F).

Subsection (c)(2)(F) states that all auction participants must supply their Holding Account number.

Rationale for Section 95912(c)(2)(F).

The provision is needed because once the auction operator has the applicant's Holding Account number, it can verify the applicant's registration status, identify the authorized account representative, and access other information on the applicant. The applicant must also already have a Holding Account in order to be able to purchase any allowances awarded to it at auction. If it does not have a Holding Account, or if it has been suspended, the applicant cannot participate in the auction.

Summary of Section 95912(d)(1).

Subsection (d)(1) states that auction participants may not release confidential information. Staff is proposing a sealed-bid auction format in part to prevent collusion. If the contents of an entity's bids or other information are circulated among participants, those with access to the information could collude to reduce the auction settlement price.

Rationale for Section 95912(d)(1).

The provision is needed to prevent participants from colluding during the auction.

Summary of Section 95912(d)(1)(A) through (d)(1)(E).

Subsections (d)(1)(A) through (d)(1)(E) state the types of information that auction applicants shall not release, including their qualification status, bidding strategy, bid prices or quantity, the financial security they provide to the auction administrator, or other information contained in the application that the auction administrator considers sensitive and will designate as confidential.

Rationale for Section 95912(d)(1)(A) through (d)(1)(E).

These provisions are needed to clarify to auction participants the information that must not be released. The provision is needed to prevent participants from colluding during the auction.

Summary of Section 95912(d)(2).

Subsection (d)(2) states that if an entity participating in the auction retains the services of an advisor, the entity must ensure the advisor does not transfer information to other participants.

Rationale for Section 95912(d)(2).

The provision is needed because auction participants must ensure that persons with access to their confidential bidding strategy do not disclose the information to other participants. This requirement is necessary to prevent collusion or market manipulation.

Summary of Section 95912(d)(3).

Subsection (d)(3) states that the Executive Officer will treat the information contained in the auction application as confidential to the extent permitted by State law.

Rationale for Section 95912(d)(3).

The provision is needed because ARB staff will not voluntarily make the information contained in the applications public, to avoid aiding collusion or market manipulation. However, the Executive Officer must comply with State law concerning what information ARB must make public.

Summary of Section 95912(d)(4)(A) and (d)(4)(B).

Subsections (d)(4)(A) and (d)(4)(B) describe the information the Executive Officer may release after an auction has concluded. The information includes the names of participating bidders and the auction settlement price

Rationale for Section 95912(d)(4)(A) and (d)(4)(B).

These provisions are needed because making some information on auction results available to the public balances the risk of disclosing information on participants' business strategies with the benefits for market transparency.

Summary of Section 95912(d)(4)(C).

Subsection (d)(4)(C) states that the Executive Officer may disclose aggregated or distributional information purchases with the names of the entities withheld. Aggregated data would refer to data summarized for different classifications of entities; for example, covered entities versus voluntarily associated entities.

Distributional information could include the number of allowances purchased by each winner, without identifying the entities themselves.

Rationale for Section 95912(d)(4)(C).

The provision is needed because releasing the data without identifying the winning entities by name would not reveal any confidential business information.

Summary of Section 95912(e).

Subsection (e) states that the Executive Officer may bar any auction participant from participating in future auctions if that participant has provided false or misleading information, or violated any other rules governing the auction. This prohibition would be in addition to any other enforcement action taken concerning the violations themselves.

Rationale for Section 95912(e).

The provision is needed because the prohibition is the surest method of maintaining the integrity of the auction, and should be an option available in addition to other enforcement actions.

Summary of Section 95912(f).

Subsection (f) states that auction participants must already be registered as participants in the California cap-and-trade system.

Rationale for Section 95912(f).

This provision is needed for two reasons. First, registration is required before an entity is provided with a Holding Account. Without a Holding Account, the entity could not purchase allowances at auction. Second, registration provides the Executive Officer with information of the entity which is necessary for market monitoring.

Summary of Section 95912(g).

Subsection (g) states that an entity whose Holding Account has been revoked or is currently suspended cannot participate in an auction.

Rationale for Section 95912(g).

The provision is needed because suspension or revocation of registration and accounts is needed as an enforcement mechanism of the cap-and-trade system. The action is applicable only to voluntarily associated entities which have no surrender compliance obligation. Without an active Holding Account, an entity cannot purchase and hold allowances.

Summary of Section 95912(h).

Subsection (h) states that the Executive Officer will specify the form and manner for submission of bids, and the bids will be considered binding offers to purchase allowances.

Rationale for Section 95912(h).

The provision is needed because the Executive Officer needs flexibility in using different methods of operating the auction, including the use of online bid mechanisms. Submitted bids must be considered binding so that the auction operator can process bid payments and access the bid guarantee mechanism, if needed.

Summary of Section 95912(i).

Subsection (i) states that registrants must provide a bid guarantee to the auction administrator at least one week before the auction.

Rationale for Section 95912(i).

The bid guarantee is needed in case a winning bidder fails to pay in a timely manner for allowances it is awarded. It must be submitted at least one week before auction to give the auction operator an opportunity to determine if it meets requirements.

Summary of Section 95912(i)(1)(A).

Subsection (i)(1)(A) states that the bid guarantee may be in the form of a bond issued by a financial institution with a United States banking license.

Rationale for Section 95912(i)(1)(A).

The U.S. banking license is required to ensure that the auction operator will not have difficulty accessing the bond.

Summary of Section 95912(i)(1)(B).

Subsection (i)(1)(B) states that the bid guarantee may be in cash in the form of a wire transfer or certified funds, such as a bank check or cashier's check.

Rationale for Section 95912(i)(1)(B).

The provision is needed because these instruments can be evaluated by the auction operator and processed quickly in the event of untimely payment by a bidder.

Summary of Section 95912(i)(1)(C).

Subsection (i)(1)(C) states that an irrevocable letter of credit issued with a United States banking license.

Rationale for Section 95912(i)(1)(C).

The provision is needed because the auction operator would obtain payment from a financial institution with which the bidder has established credit.

Summary of Section 95912(i)(1)(D).

Subsection (i)(1)(D) states that the auction operator will accept qualifying financial instruments from financial institutions with a Canadian banking license if California links to programs in one or more Canadian provinces.

Rationale for Section 95912(i)(1)(D).

The provision is needed because if California links its system with GHG ETS in one or more Canadian provinces, it is possible that some California allowances will be purchased at auction by entities located in Canada. These entities may need to use Canadian financial institutions, so the auction operator needs to accept instruments from institutions with Canadian banking licenses.

Summary of Section 95912(i)(2).

Subsection (i)(2) states that the value of the bid guarantee must be greater than or equal to the sum of the value of the bids submitted by the auction participant.

Rationale for Section 95912(i)(2).

The provision is needed because bid guarantees are common features of auctions to deter manipulative bidding. Without such a mechanism, bidders could submit multiple bids, then default on paying if the auction settlement price was higher than they desired. This practice would jeopardize the integrity of the auction.

Summary of Section 95912(j)(1) through (j)(6).

Subsections (j)(1) through (j)(6) describe the information the Executive Officer must make public at least 60 days before an auction. The notice shall include the date and time of the auction; instructions for applying for auction participation; instruction on how to submit bids; the procedures the auction operator will follow to conduct the auction; the administrative requirements for participation; and the number of GHG allowances to be auctioned.

Rationale for Section 95912(j) through (j)(6).

These provisions are needed because public notice is necessary so that potential participants can complete the registration process, develop a bidding strategy, and arrange financing in time for the auction.

Summary of Section 95912(k)(1).

Subsection (k)(1) states that the auction operator will process the bid guarantees.

Rationale for Section 95912(k)(1).

The provision is needed because the auction operator will need to determine the value of bids for which a participant has submitted a valid guarantee.

Summary of Section 95912(k)(2).

Subsection (k)(2) states that the auction operator will determine that the bids submitted by a participant conform to the holding and purchase limits and value of the bid guarantee submitted.

Rationale for Section 95912(k)(2).

The provision is needed because the auction operator will disqualify individual bids that exceed any of the limits.

Summary of Section 95912(k)(3).

Subsection (k)(3) states that the auction operator will determine the winning bids and auction settlement price.

Rationale for Section 95912(k)(3).

The provision is needed because the auction operator has responsibility for these functions.

Summary of Section 95912(k)(4).

Subsection (k)(4) states that the auction operator will inform the Executive Officer of the results.

Rationale for Section 95912(k)(4).

The provision is needed because the Executive Officer is responsible for ensuring the integrity of the auction. The results must be reported to the Executive Officer for approval before actual awarding of and payment for allowances occurs.

Summary of Section 95912(l).

Subsection (l) describes the actions the Executive Officer must take after an auction concludes.

Rationale for Section 95912(l).

The provision is needed because the auction operator only conducts the auction and determines winners. All transactions involving distribution of allowances require action by the Executive Officer. No payments can be processed until this occurs.

Summary of Section 95912(l)(1).

Subsection (l)(1) states that after the auction, the Executive Officer will certify that the auction was conducted pursuant to the regulation.

Rationale for Section 95912(l)(1).

This provision is needed to ensure no allowances are awarded or payments processed until the Executive Officer is certain that the auction rules have been followed.

Summary of Section 95912(l)(2)(A).

Subsection (l)(2)(A) states that after certifying the auction was conducted properly, the Executive Officer will instruct the auction operator to collect payment from winning bidders.

Rationale for Section 95912(l)(2)(A).

The provision is needed because the auction operator must collect payments before the Executive Officer will transfer allowances to the winners' Holding Accounts.

Summary of Section 95912(l)(2)(B).

Subsection (l)(2)(B) states that after certifying the auction was conducted properly, the Executive Officer will instruct the auction operator to declare the bid guarantee mechanism forfeit by any entity that fails to make full payment for awarded allowances when payment is due. The auction operator will access the bid guarantee to make up any shortfall in payment.

Rationale for Section 95912(l)(2)(B).

The provision is needed because the auction operator must collect payments before the Executive Officer will transfer allowances to the winners' Holding Accounts.

Summary of Section 95912(l)(2)(C).

Subsection (l)(2)(C) states that after certifying the auction was conducted properly, the Executive Officer will instruct the auction operator to deposit the proceeds for allowances allocated by ARB into the Air Pollution Control Fund.

Rationale for Section 95912(l)(2)(C).

The provision is needed because proceeds for allowances allocated for auction by ARB must go to a State account where they are available for appropriation by the Legislature.

Summary of Section 95912(l)(2)(D).

Subsection (l)(2)(D) states that after certifying the auction was conducted properly, the Executive Officer will instruct the auction operator to distribute auction proceeds to entities that consigned allowances to the auction under the provisions of section 95910.

Rationale for Section 95912(l)(2)(D).

The provision is needed to provide authority for the Executive Officer to ensure that those entities that consigned allowances are paid for them.

Summary of Section 95912(l)(3).

Subsection (l)(3) states that after determining that allowances have been paid for, the Executive Officer will instruct the accounts administrator to transfer the serial numbers of allowances to the Holding Accounts of the winning bidders.

Rationale for Section 95912(l)(3).

The provision is needed because allowances belong to purchasers after payment has been received. Until payment has been received, the allowances either belong to ARB or have been consigned to the Executive Officer for auction. Therefore, the Executive Officer must determine when payment has been completed and instruct the accounts administrator to transfer the allowances.

Summary of Section 95912(l)(4).

Subsection (l)(4) states that after certifying the auction was conducted properly, the Executive Officer will inform any GHG ETS to which California is linked of the allowances distributed.

Rationale for Section 95912(l)(4).

The provision is needed because California must inform linked systems of the allowances that it has distributed, so that the other systems can recognize them as valid.

Summary of Section 95912(l)(5).

Subsection (l)(5) states that the Executive Officer will publish the results at www.arb.ca.gov.

Rationale for Section 95912(l)(5).

This provision is necessary to ensure transparency of the auction proceedings.

Section 95913. Sale of Allowances from the Allowance Price Containment Reserve Account.

Summary of Section 95913(a).

Subsection (a) states that the Executive Officer may administer sales from the Allowance Price Containment Reserve Account (also referred to as the *Reserve*) or designate an entity to serve as auction administrator.

Rationale for Section 95913(a).

This provision gives the Executive Officer the flexibility to contract with an outside entity to administer transactions.

Summary of Section 95913(b).

Subsection (b) states that if California links with other GHG ETS, the linkage agreement will specify whether entities registered into the linked systems will be eligible to purchase from the Reserve.

Rationale for Section 95913(b).

This provision is needed because staff cannot make a determination on eligibility before linking agreements have been created. Under the current staff proposal, entities must be registered into the California cap-and-trade system under section 95830 before they can participate in the Reserve sales.

Summary of Section 95913(c)(1)(A).

Subsection (c)(1)(A) states that only covered entities, including opt-in covered entities, are eligible to participate in sales from the Reserve.

Rationale for Section 95913(c)(1)(A).

This provision is needed because staff is proposing a Reserve to mitigate price increases during periods of short supplies, especially when these occur near to compliance deadlines. Since voluntarily associated entities do not have a compliance obligation, they can simply avoid purchasing allowances when prices are high.

Summary of Section 95913(c)(1)(B).

Subsection (c)(1)(B) states that covered entities may only purchase from the Reserve if they do not hold any compliance instruments in their Holding Accounts.

Rationale for Section 95913(c)(1)(B).

This provision is needed because staff is proposing the Reserve to help ensure that compliance may be achieved at a reasonable cost. Staff intends the benefit to go to entities that have had difficulty finding compliance instruments at a reasonable cost, not those that can meet their compliance needs and still maintain a balance in their Holding Accounts for speculative purposes.

Summary of Section 95913(c)(2).

Subsection (c)(2) states that all of the allowances in the Reserve will be available for purchase at each sale.

Rationale for Section 95913(c)(2).

This provision is needed because staff concluded that if shortages occur close to a compliance deadline, then the Reserve needs to be available in its entirety.

Summary of Section 95913(c)(3)(A) and (c)(3)(B).

Subsections (c)(3)(A) and (c)(3)(B) state that the first Reserve sale will be conducted on March 4, 2012. After the first Reserve Sale, further Reserve sales will take place three weeks after each quarterly allowance auction.

Rationale for Section 95913(c)(3)(A) and (c)(3)(B).

Staff propose this date to allow entities to complete the registration process and for the first auction to conclude. Staff proposes this schedule so that entities may use the Reserve sales to supplement their auction purchases.

Summary of Section 95913(c)(3)(C).

Subsection (c)(3)(C) states that the sale administrator will publish a notice for each sale four weeks prior to the sale.

Rationale for Section 95913(c)(3)(C).

This provision is needed because covered entities will need time to prepare their purchase strategies following each auction, to submit their bids, and to arrange financing.

Summary of Section 95913(c)(4).

Subsection (c)(4) states that purchases of allowances from the Reserve will be subject to the holding limit.

Rationale for Section 95913(c)(4).

This provision is necessary because the Reserve is intended to aid entities that need allowances for compliance rather than speculative purposes. Covered entities have a limited exemption for allowances held in their Compliance Accounts. The exemption is intended to allow them to meet compliance obligations. If they exceed that limit they should have no need to access the Reserve.

Summary of Section 95913(d)(1).

Subsection (d)(1) states that the allowances in the Reserve will be evenly divided into three pools, referred to as *tiers*.

Rationale for Section 95913(d)(1).

This provision is needed because staff proposes the division to allow the allowances to be available at different prices.

Summary of Section 95913(d)(2)(A) through (d)(2)(C).

Subsections (d)(2)(A) through (d)(2)(C) list the prices for each tier to be used in 2012. The price for allowances will be $40/metric ton for the first tier, $45/metric ton for the second tier, and $50/metric ton for the third tier.

Rationale for Section 95913(d)(2)(A) through (d)(2)(C).

These provisions are needed because ARB will specify prices for 2012, then use an inflator to raise prices in later years.

ARB proposes the use of fixed prices for sales from the Reserve so that program administrators do not need to make a determination that market conditions require an intervention. This certainty of the Reserve being available at established prices is an important aspect of the design.

ARB proposes setting the prices for the three tiers at $40, $45, and $50 because if allowance prices remain within the anticipated range (as described in

Appendix N: Supporting Documentation for the Economic Analysis), no allowances will be purchased from the Reserve because the established sales prices would be higher than the estimated market price of allowances. Consequently, when no allowances are purchased from the Reserve, the total number of instruments that can be used for compliance (allowances plus the offset limit) is unchanged by the creation of the allowance reserve. Under these conditions, the environmental integrity of the program is maintained, and the emissions reductions required by covered sources remains unchanged.

Appendix N examines scenarios that could result in allowance prices that are substantially above the price estimated under the main policy case for 2020. An allowance reserve could potentially prevent the higher allowance prices in these circumstances if it is large enough to accommodate the estimated shortfalls in emissions reductions from the complementary measures. ARB estimated that the allowance reserve needed to accommodate potential shortfalls in direct reductions would be in the order of 2 percent to 5 percent of the total allowance budget.

This protection against high prices is limited, however, because the number of allowances in the Reserve is limited. Once the allowances in the Reserve are all purchased, there is no additional buffer against higher-than-expected prices.

The limited nature of the proposed reserve distinguishes it from a hard allowance price cap. Under a hard price cap, a maximum allowance price is established, and additional allowances are made available at the cap price, typically in unlimited quantity. Under such conditions, the environmental integrity of the program is not maintained if additional allowances are sold at the price cap. The allowance reserve discussed here does not share these features with a hard price cap.

Summary of Section 95913(d)(3).

Subsection (d)(3) proposes that after 2012, the tier prices for a given calendar year will equal the prices for the previous calendar year, plus five percent and a measure of inflation, the Consumer Price Index for All Urban Consumers.

Rationale for Section 95913(d)(3).

Staff proposes an inflator mechanism based on the expectation that marginal abatement costs and allowance prices will increase over time as lower cost abatement measures are undertaken first. Reserve sale prices would need to increase to reflect the increased marginal abatement cost and the inflation rate, otherwise the Reserve would no longer be the seller of last resort as intended.

Summary of Section 95913(e).

Subsection (e) describes how covered entities must submit their bids to purchase allowances from the Reserve. The bids are due to the sales administrator two weeks before each sale is conducted.

Rationale for Section 95913(e).

The provision is necessary so that the sales administrator has time to process the bids. Staff is proposing minimal requirements on the bids themselves. The requirements are necessary to ensure that the sales proceed efficiently.

Summary of Section 95913(e)(1).

Subsection (e)(1) states that the bids will include the number of allowances the covered entity wishes to purchase from each of the three tiers, in multiples of 1,000 metric tons.

Rationale for Section 95913(e)(1).

The provision is necessary to simplify the bidding and award process. The bid must specify the number of allowances from each tier. The total number of allowances, combined with the entity's existing holdings, must be less than the holding limit.

Summary of Section 95913(e)(2).

Subsection (e)(2) states that bidders must provide a bid guarantee equal to the value of the bids they submit.

Rationale for Section 95913(e)(2).

The provision is necessary because without this requirement, bidders could default on their bids. This might force the sales administrator to rerun the sale.

Summary of Section 95913(e)(2)(A).

Subsection (e)(2)(A) states that the bid guarantee may be in the form of a bond issued by a financial institution with a U.S. banking license.

Rationale for Section 95913(e)(2)(A).

The provision is necessary because the sales administrator could easily recover payment for the allowances from a bond.

Summary of Section 95913(e)(2)(B).

Subsection (e)(2)(B) states that the bid guarantee may be in the form of cash, in the form of a wire transfer, or certified funds, such as a bank check or cashier's check.

Rationale for Section 95913(e)(2)(B).

The provision is necessary because the sales administrator could easily recover payment for the allowances from these instruments.

Summary of Section 95913(e)(2)(C).

Subsection (e)(2)(C) states that the bid guarantee may be in the form of an irrevocable letter of credit issued by a financial institution with a U.S. banking license.

Rationale for Section 95913(e)(2)(C).

The provision is necessary because the sales administrator could easily recover payment for the allowances from letters of credit. The requirement for a U.S. banking license is included to simplify transactions.

Summary of Section 95913(e)(2)(D).

Subsection (e)(2)(D) states that if California links with GHG ETS operated by one or more Canadian Provinces, then bonds or irrevocable letters of credit from financial institutions with Canadian banking licenses would be acceptable.

Rationale for Section 95913(e)(2)(D).

The provision is necessary if California links with GHG ETS operated by Canadian Provinces, because the linking agreements may allow Canadian entities to purchase from the Reserve. In this case, the entities may well be transacting through Canadian banks.

Summary of Section 95913(f)(1).

Subsection (f)(1) states that the sales administrator will conduct sales from each tier starting with the lowest-priced tier and proceeding to the highest.

Rationale for Section 95913(f)(1).

The provision is necessary because the sales administrator will be evaluating each purchase against the holding limit. By conducting sales from each tier from lowest to highest price, the administrator will disqualify the higher-priced bids.

Summary of Section 95913(f)(2)(A).

Subsection (f)(2)(A) states that the sales administrator will disqualify bids once purchases exceed the bidding entity's holding limit.

Rationale for Section 95913(f)(2)(A).

The provision is necessary because no entity's holdings may exceed the holding limit.

Summary of Section 95913(f)(2)(B).

Subsection (f)(2)(B) states that the sales administrator will disqualify bids once the value of purchases exceeds the value of the bidding entity's bid guarantee.

Rationale for Section 95913(f)(2)(B).

The provision is necessary because if the sales administrator accepts the bids beyond the value of the bid guarantee, there is risk that an entity may not pay for the allowances. This would affect the integrity of the auction.

Summary of Section 95913(f)(3).

Subsection (f)(3) states that if the total number of bids for a tier is less than the total available, bidders will receive all the allowances for which they bid.

Rationale for Section 95913(f)(3).

The provision is necessary because the sales administrator will fill all the qualified bids from a tier if the tier is not depleted.

Summary of Section 95913(f)(4).

Subsection (f)(4) describes the process the sales administrator will use if the number of qualified bids for a tier exceeds the number of allowances in the tier.

Rationale for Section 95913(f)(4).

The provision is necessary because there must be a procedure in place if a tier becomes depleted.

Summary of Section 95913(f)(4)(A).

Subsection (f)(4)(A) states that if there are more bids for a tier than there are allowances remaining, the share of allowances to be awarded to each bidder will equal the number of allowances for which one entity bids, divided by the total number of bids.

Rationale for Section 95913(f)(4)(A).

The provision is necessary because if a tier becomes depleted during a sale, the administrator will prorate the purchases among qualified bids. Once a tier is depleted, it will not be replenished. ARB is filling the Reserve with allowances issued at the beginning of the program and does not intend to replenish the Reserve with allowances issued through 2020. However, ARB does intend to transfer allowances remaining unsold at auction to the Reserve.

Summary of Section 95913(f)(4)(B).

Subsection (f)(4)(B) states that the number of allowances awarded to each bidder will equal the bidder's share, as calculated in 95913(f)(4)(A), times the number of allowances in the tier, rounded to the lowest whole number.

Rationale for Section 95913(f)(4)(B).

The provision is necessary because it allows the administrator to empty the tier while treating each bidder equally.

Summary of Section 95913(f)(5).

Subsection (F)(5) states that the sales administrator will inform the Executive Officer of the sales results.

Rationale for Section 95913(f)(5).

The provision is necessary because the Executive Officer will have to certify that the sale was conducted properly under the regulation.

Summary of Section 95913(g)(1) through (g)(2).

Subsections (g)(1) through (g)(2) detail the post-sale actions by the Executive Officer. The Executive Officer must certify that the sale was conducted according to the regulation. After approving the sale, the Executive Officer will authorize the reserve sale administrator to process payments for the allowances purchased.

Rationale for Section 95913(g) (1) through (g)(2).

These provisions are necessary because some actions must be taken by the Executive Officer after the sale. The Executive Officer must determine that the sale administrator conducted the sale appropriately before allowances can be distributed. The reserve sale administrator cannot process payments until the Executive Officer approves the conduct of the sale.

Summary of Section 95913(g)(3).

Subsection (g)(3) states that after determining that the payments have been placed into the Air Pollution Control Fund, the Executive Officer will authorize the accounts administrator to transfer the allowances purchased from the Reserve account to the winning bidders' Compliance Accounts.

Rationale for Section 95913(g)(3).

The provision is necessary because the Executive Officer will authorize allowance transfers once payment has been processed. The allowances are placed in the winning bidders' Compliance Account because the Reserve is intended for use by those entities finding it difficult to acquire allowances during times of tight supply. ARB does not intend the allowances to be available for further speculation.

Summary of Section 95913(g)(4).

Subsection (g)(4) states that the Executive Officer will inform the GHG ETS to which California has linked of the serial numbers of the allowances sold.

Rationale for Section 95913(g)(4).

The provision is necessary because when California links to other GHG ETS, the systems must inform each other when compliance instruments have been placed into circulation, so that the instruments may be recognized as valid in each system.

Summary of Section 95913(g)(5).

Subsection (g)(5) states that the Executive Officer will publish all sales results online.

Rationale for Section 95913(g)(5).

The provision is necessary because staff proposes to have all results be a matter of public record. The cost-containment mechanism was designed in part to provide information on the compliance costs of the program. In addition, staff believes the public should know who is benefitting from this distribution of allowances.

Section 95914. Disclosure of Direct and Indirect Corporate Associations.

Summary of Section 95914(a).

Subsection (a) requires that entities disclose direct and indirect corporate associations when they register. This subsection contains the definitions of the associations.

Rationale for Section 95914(a).

This provision is necessary because registered entities may have corporate associations that allow them to coordinate their market activities. Staff is proposing disclosure of these relationships so that market monitors will be able to identify transactions involving affiliates. In addition, if ARB were to be unaware of these relationships it would be unable to apply holding and purchase limits in a meaningful way. Corporate affiliates would be able to control a much larger share of the market for compliance instruments.

Summary of Section 95914(a)(1)(A) through (a)(1)(E).

Subsections (a)(1)(A) through (a)(1)(E) contain the criteria for determining whether two entities have a direct corporate association. These include the share of share ownership, appointment of directors, voting power, or other means of control of another entity. In addition, subsection (a)(1)(E) states that a corporate association would exist if one entity holds compliance instruments in which the other has an ownership interest.

Rationale for Section 95914(a)(1)(A) through (a)(1)(E).

These provisions are needed to give clear guidance about how to determine which corporate associations must be disclosed.

Summary of Section 95914(a)(2).

Subsection (a)(2) contains the criteria for determining whether two entities have an indirect corporate association. This type of association occurs when an entity has an association with an entity through a third entity, or a chain of entities.

Rationale for Section 95914(a)(2).

This provision is needed to give clear guidance about how to determine which corporate associations must be disclosed.

Summary of Section 95914(b).

Subsection (b) requires that if California links to other GHG ETS, then registered entities must disclose corporate associations with entities in those systems.

Rationale for Section 95914(b).

This provision is needed to give clear guidance about how to determine which corporate associations must be disclosed.

Summary of Section 95914(c)(1) through (c)(3).

Subsections (c)(1) and (c)(3) contain the list of information which entities must provide when disclosing corporate associations. This includes names of the other entities, the type of corporate association, and a brief description of the association, such as subsidiary, partnership, corporate parent, sister company, or other.

Subsection (c)(2) gives the entity the opportunity to report the share of the corporate association's purchase and holding limits allocated to each entity in the association.

Rationale for Section 95914(c)(1) through (c)(3).

These provisions are necessary to provide basic identification of the members of a corporate association. In addition, subsection (c)(2) is needed to enable the auction administrator to apply purchase and holding limits to members of a corporate association. The limits treat the holdings and purchases of members of an association as if they were held by one entity. Staff is proposing that members of an association be able to allocate the limit among the members so that each entity will always know how the limitations apply to it. When the allocation is disclosed, the auction operator and the Executive Officer will ensure that the sum of the allocated shares is less than the holding and purchase limits.

Summary of Section 95914(d)(1) through (d)(4).

Subsections (d)(1) through (d)(4) contain the list of times when corporate associations must be disclosed or the disclosure updated. Subsection (d)(1) requires that disclosure be made when an entity initially registers under section 95830. Subsection (d)(2) requires that disclosure be made any time an association is created or exists. Subsection (d)(3) requires disclosure whenever there is a material change in the information already disclosed. Subsection (d)(4) requires disclosure at least 60 days before an auction.

Rationale for Section 95914(d)(1) through (d)(4).

These provisions are necessary so that entities understand their responsibilities of when they must report or update the information retained by ARB.

Summary of Section 95914(e)(1).

Subsection (e)(1) makes the total number of allowances purchased at auction by a group of entities with a corporate association subject to the purchase limit as if they were one entity.

Rationale for Section 95914(e)(1).

This provision is needed to correctly apply the purchase limit. ARB intends the limit to restrict the ability of an entity or group of entities from gaining a dominant share of the market for instruments.

Summary of Section 95914(e)(2)(A) through (e)(2)(C).

Subsection (e)(2) allows members of a corporate association to allocate shares of the limit among themselves. The sum of shares allocated to the members of the corporate association must sum to the purchase limit. After they inform the Executive Officer of the allocation, the auction administrator will treat the entity's allocated share as its purchase limit.

Rationale for Section 95914(e)(2)(A) through (e)(2)(C).

Subsections (e)(2)(A) through (e)(2)(C) are necessary so that members of a corporate association can clarify their share of their association's purchase limit between themselves. By informing the Executive Officer, they can ensure that the limit will be applied correctly.

Summary of Section 95914(e)(3)(A) through (e)(3)(C).

These provisions describe how the purchase limit will be applied to members of a corporate association if they do not inform the Executive Officer of an allocation of the shares of the purchase limit among themselves. To evaluate the purchase limit, the auction administrator will pool the bids from all members of the association, and order them from highest to lowest bid price. The administrator will then accept the bids in declining price order until the association's purchase limit is reached. The administrator will then disqualify any remaining bids. The auction administrator will conduct this process before the auction itself.

Rationale for Section 95914(e)(3)(A) through (e)(3)(C).

These provisions are necessary to instruct the administrator how to apply the purchase limit to members of a corporate association when they have not allocated the purchase limit among themselves.

Summary of Section 95914(f)(1).

Subsection (f)(1) makes the total number of compliance instruments held by members of a corporate association subject to the holding limit as if the association were one entity.

Rationale for Section 95914(f)(1).

This provision is necessary to correctly apply the holding limit. ARB intends the limit to restrict the ability of an entity or group of entities from gaining a dominant share of the market for instruments. Without this requirement, a corporate

association could expand its share of the market by creating and registering more affiliates.

Summary of Section 95914(f)(2)(A) and (f)(2)(B).

Subsections (f)(2)(A) and (f)(2)(B) describe how entities that are part of a corporate association may allocate the holding limit among themselves. The sum of shares allocated to each member must sum to the holding limit. The association must inform the Executive Officer of the allocation before the limit can be correctly applied.

Rationale for Section 95914(f)(2)(A) and (f)(2)(B).

These provisions are necessary because ARB is proposing that the holding limit applies to members of a corporate association as if they were one entity.

Summary of Section 95914(f)(3).

Subsection (f)(3) requires that if the members of a corporate association do not inform the Executive Officer of a an allocation of the holding limit among themselves, then the accounts administrator will not record a transaction that would result in the holdings of the members of a corporate association exceeding the holding limit.

Rationale for Section 95914(f)(3).

Subsection (f)(3) is necessary in the event that members of a corporate association do not report an allocation of the holding limit to the Executive Officer. This subsection gives the default treatment of the limit, unless the members of the association take advantage of the allocation option.

Section 95915. Identifying Disclosable Bidding Associations.

Summary of Section 95915(a).

Subsection (a) requires entities registering for the auction to disclose the existence of bidding associations with any entities registered into the California cap-and-trade system or into a GHG ETS with which California has linked.

Rationale for Section 95915(a).

The provision is needed to require entities participating in California's auction to disclose if they are participating in the auction with another registered entity. Staff is proposing the requirement so that ARB can monitor auctions for collusive behavior.

Summary of Section 95915(b)(1) through (b)(3).

Subsections (b)(1) through (b)(3) provide a list of criteria for determining whether a bidding association exists. These include whether the entity has an agreement with another entity; is partnered with another entity for bidding purposes; or has agreed to provide advisory services except for investment advice.

Rationale for Section 95915(b)(1) through (b)(3).

These provisions are necessary to inform auction participants of the criteria governing disclosure of bidding associations.

Summary of Section 95915(c)(1) and (c)(2).

Subsection (c)(1) requires that bidding associations be disclosed during the auction registration process. Subsection (c)(2) lists the disclosure requirements for bidding associations. These include a description of the agreement, relationships between members of the association, including which entity may be holding instruments on behalf of another, and a copy or description of any agreement.

Rationale for Section 95915(c)(1) and (c)(2).

Subsection (c)(1) is necessary to ensure the Executive Officer has the information prior to the auction. Subsection (c)(2) is necessary to make clear to the auction participants what type of information must be disclosed. The disclosed information will help the Executive Officer monitor the bidding behavior of participants.

Summary of Section 95915(d)(1) through (d)(3).

Subsections (d)(1) through (d)(3) contain the requirements for when disclosures must be made and when an entity can communicate information on its auction participation. Subsection (d)(1) requires disclosure at least 30 days prior to the auction. Subsection (d)(2) prohibits communication by an entity with another auction participant if there has been no disclosure of a bidding association between the two. Subsection (d)(3) prohibits an entity from participation in the auction if it has a material change to its bidding association disclosure less than 30 days from the auction.

Rationale for Section 95915(d)(1) through (d)(3).

These provisions are necessary to ensure that there is no undisclosed communication between bidders at an auction. Subsection (d)(1) is needed to ensure all associations have been disclosed a sufficient interval prior to the auction, so that the auction can be properly monitored. Subsection (d)(2) is needed to prohibit communication between bidders. Subsection (d)(3) prohibits

the creation of new bidding associations after the auction disclosure deadlines have passed.

These provisions will ensure that the auction can be monitored for potential collusion between bidders.

Summary of Section 95915(e)(1).

Subsection (e)(1) applies the purchase limit at an auction to the members of a bidding association which are designated as "the recipient" of a beneficial purchase by another entity.

Rationale for Section 95915(e)(1).

The provision is needed to address when an entity has other registered entities make purchases on its behalf. An entity could easily escape the purchase limit by such arrangements. However, part of the required disclosure is to have a purchasing entity identify the ultimate recipient of the purchased instrument. The purchase limit will then correctly be applied to the recipient, not to the apparent purchaser.

Summary of Section 95915(e)(2)(A) and (e)(2)(B).

Subsections (e)(2)(A) and (e)(2)(B) permit the entities within a bidding association to allocate the purchase limit among those entities in the association and inform the Executive Officer of the allocation. The sum of the shares allocated must be less than or equal to the purchase limit. The share allocated to an individual entity becomes its purchase limit.

Rationale for Section 95915(e)(2)(A) and (e)(2)(B).

These provisions are needed so that entities that are part of a bidding association may enter an auction knowing exactly the number of allowances each will be allowed to purchase on its own behalf. The Executive Officer must be aware of the allocation before the auction to evaluate whether it was correctly calculated.

Summary of Section 95915(e)(3).

Subsection (e)(3) requires the auction operator to calculate shares of the purchase limit if entities in a bidding association fail to declare an allocation to the Executive Officer. The limit for entities designated as "purchaser" is the purchase limit less the sum of bids submitted by entities in the association designated as "recipient," divided by the number of entities designated as "purchaser." Thus, all "purchasers" would end up with an equal share of the limit as a default.

Rationale for Section 95915(e)(3).

The provision is necessary in case entities in a bidding association do not allocate the purchase limit among themselves.

Subarticle 11. Trading and Banking.

Section 95920. Trading.

Summary of Section 95920(a).

Subsection (a) contains a list of actions that are explicitly prohibited in the California cap-and-trade system.

Rationale for Section 95920(a).

The list of prohibited actions is needed to enable ARB to take enforcement actions against entities that attempt to manipulate the market. The list of prohibited activities attempt to capture actions that are part of manipulative activities.

Summary of Section 95920(a)(1).

Subsection (a)(1) requires that transaction reports include the names of authorized account representatives of those involved in a trade.

Rationale for Section 95920(a)(1).

The provision is needed because ARB needs to know who has an ownership interest in the instruments being traded, in order to detect the exercise of market power.

Summary of Sections 95920(a)(2)(A) through (a)(2)(F).

Subsections 95920(a)(2)(A) through (a)(2)(F) prohibit trades involving a number of techniques used to manipulate markets, including manipulative or deceptive devices; attempts to corner a market; fraud; false, misleading, or inaccurate reporting or documentation; or other efforts to falsify or conceal material facts.

Rationale for Section 95920(a)(2)(A) through (a)(2)(F).

The prohibitions are needed to because ARB must be able to take enforcement against an entity attempting to manipulate markets or deceive other market participants.

Summary of Section 95920(b)(1) and (b)(2).

Section (b)(1) defines the *holding limit* as the maximum number of California compliance instruments that can be held by an entity or a group of entities with a

corporate association. Section (b)(2) applies the limit to any entity with a Holding Account.

Rationale for Section 95920(b)(1) and (b)(2).

Sections (b)(1) and (b)(2) are needed to define the holding limit that will apply to each entity with a Holding Account. The limit applies to entities that have a corporate association with each other, as defined in section 95914.

The purpose of a holding limit is to prevent a market participant, or a group of market participants that can coordinate their buying and selling, from gaining too large a share of the goods in a market. The limits are common features in commodity markets.

Summary of Section 95920(b)(3).

Section (b)(3) contains the formula for calculating the holding limit. The formula calculates the holding limit in millions of metric tons:

Holding Limit = 2.5 million metric tons + 0.025*(Annual Allowance Budget – 2.5 million metric tons).

The holding limit is calculated for each year using that year's Annual Allowance Budget. ARB selected this formula based primarily on recommendations by a consultant to the WCI Markets Committee.[101]

Rationale for Section 95920(b)(3).

The provision is needed because account holders must know at all times the holding limit that applies each year. The formula adjusts the holding limit for changes in the allowance budget. This will allow the holding limit to increase when the scope of the system is enlarged in the second period, and to decrease when the cap decreases over time.

The size of the limit, coupled with the limited exemption, represents a trade-off between having a limit that is small enough to reduce opportunities for market manipulation and a limit that is so small that it reduces banking and market liquidity by restricting the activity of non-covered entities. As the WCI consultant

[101] Harris, Jeffrey H. *Western Climate Initiative Markets Committee Report on Holdings Limits.* May 6, 2010.

concluded, economic theory provides little practical guidance to setting the trade-off for a market that does not yet exist.[102]

Summary of Section 95920(b)(4)(A)

Subsection (b)(4)(A) provides a limited exemption from the holding limit for allowances placed in a compliance account by covered entities within a single calendar year. The limit to the transfer of allowances added to an entity's compliance account is equal to the verified emissions reported for the entity for the previous year. The verification statement must be a positive or qualified positive statement.

Rationale for Section 95920(b)(4)(A)

This provision is needed to have a holding limit that treats all covered and voluntarily associated entities equally. The exemption applies only to allowances transferred to a compliance account in a single year.

Staff concluded that the verified emissions would be the best available estimate of an entity's current emissions. Using the verified emissions to set the exemption means that the exemption would not be large enough to exempt allowances an entity accumulates to cover growth in emissions.

Summary of Section 95920(b)(4)(B)

Subsection (b)(4)(B) states that the total number of allowances which can be held in a compliance account during a calendar year is the sum of previous annual transfer limits.

Rationale for Section 95920(b)(4)(B)

This provision is needed in order for the limited exemption to be cumulative. The approach allows the exemption to be high enough to accommodate holdings needed prior to the triennial compliance.

Summary of Section 95920(b)(4)(C)

Subsection (b)(4)(C) states that on December 31 of the calendar year following the end of a compliance period the limited exemption will be reduced by the sum of the entity's verified emissions over that compliance period.

Rationale for Section 95920(b)(4)(C)

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[102] Harris, Jeffrey H. *Western Climate Initiative Markets Committee Report on Holdings Limits.* May 6, 2010, p. ii.

This provision is needed in order for the limited exemption to reflect changes in the number of allowances a covered entity would need to hold over the triennial compliance cycle. The limit is reduced by the entity's total emissions over a compliance period after that entity has met the triennial compliance deadline. The limit will still be high enough to allow the entity to begin accumulating allowances for the next compliance period. At the same time, the exemption does not continue to grow in an unlimited fashion so that the covered entity is effectively no longer bound by the holding limit.

Summary of Section 95920(b)(4)(D)

Subsection (b)(4)(B) states that if a positive or qualified positive verification statement is not available then ARB will calculate the exemption based on emissions assigned to the entity.

Rationale for Section 95920(b)(4)(D)

This provision is needed to allow ARB to calculate the holding limit exemption for covered entities when they do not have a positive or qualified positive verification statement for their emissions from the previous year.

Summary of Section 95920(b)(5).

Subsection 95920(b)(5) states that if the Executive Officer determines that a transaction by an entity would result in the number of compliance instruments held by that entity being greater than the holding limit, the Executive Officer will not approve the transaction.

Rationale for Section 95920(b)(5).

This provision is needed to enforce the holding limit. ARB has two choices on how to enforce the limit. First, it could allow transactions to proceed, then review them for conformance. If violations were found, ARB would have to penalize an entity involved in the trade and then arrange to unwind the transaction. Second, it could rely on the section 95921 requirement that each trade must conform to the proposed rules for holding or trading compliance instruments or it will not be accepted by the accounts administrator. This means all trades would be monitored for conformance to the holding limit and other rules, and would not be recorded if a violation is detected. Staff concluded that the second approach would be less resource-intensive to operate.

Summary of Section 95920(b)(6).

Subsection 95920(b)(6) states that the holding limit will treat holdings of entities with a corporate association as being held by a single entity. This restriction will not apply if existing law or regulation prohibits coordinated market activity by the associated entities, including the transfer of compliance instruments between accounts controlled by the associated entities.

Rationale for Section 95920(b)(6).

This provision is needed to deal with the possibility that individual entities registered into the cap-and-trade system may be coordinating their market activities with other entities that have a corporate association. The main purpose of a holding limit is to prevent an entity from acquiring a large enough share of compliance instruments that it can influence market prices. Entities subject to an individual holding limit could jointly control enough compliance instruments to affect market prices if they coordinated their market activity.

Summary of Section 95920(b)(7).

Subsection 95920(b)(7) states that the holding limit treat beneficial holdings by an agent as part of the holding of the owner. A beneficial holding refers to compliance instruments held by one entity on behalf of another entity that has an ownership interest.

Rationale for Section 95920(b)(7).

This provision is needed to calculate the holding limit to reflect the entity that actually controls compliance instruments. Without this provision, entities could escape the holding limit by simply having agents purchase and hold allowances on their behalf. At the same time, the provision protects entities interested in buying and selling on behalf of clients from having their actions curtailed by the holding limit.

Summary of Section 95920(c)(1).

Subsection 95920(c)(1) states that the Executive Officer may restrict the number of compliance instruments held by a covered entity or opt-in covered entity in response to violations by the entity. The restriction will allow the entity to accumulate sufficient compliance instruments to meet obligations but not enough to participate in speculative transactions.

Rationale for Section 95920(c)(1).

This provision is needed as a response to rule violations. Obviously the Executive Officer cannot suspend or revoke the registration of covered entities. Staff instead proposes to restrict the number of instruments the violator could hold. This would allow the entity to meet its obligations without giving it more opportunities to violate market rules.

Summary of Section 95920(c)(2).

Subsection 95920(c)(2) states that the Executive Officer may raise the annual surrender obligation for covered entities and opt-in covered entities in response to violations.

Rationale for Section 95920(c)(2).

This provision is needed as a response to rule violations. The provision would reduce some of the flexibility given to covered entities through the three-year compliance period by forcing them to meet a greater percentage of their triennial compliance obligation through the annual compliance "payment."

Summary of Section 95920(c)(3).

Subsection 95920(c)(3) states that the Executive Officer may suspend or revoke the registration of opt-in covered entities, voluntarily associated entities, and other registered market participants

Rationale for Section 95920(c)(3).

This provision is needed as a response to rule violations. The Executive Officer must have the authority to remove participants for serious or repeated violations.

Section 95921. Conduct of Trade.

Summary of Section 95921(a).

Subsection (a) requires that the accounts administrator will examine all transactions reports submitted by account holders prior to recording them. The accounts administrator will not accept transactions if the administrator determines that the transaction does not conform to the cap-and-trade system rules. For example, if the administrator will determine if a transaction would result in an account holder exceeding the holding limit set forth in 95920(b), the administrator will inform the parties to the trade that the transaction was not recorded into the accounts system.

Rationale for Section 95921(a).

This provision is needed because the system of accounts maintained by the accounts administrator is the final record of who owns each compliance instrument. The cap-and-trade system rules are set up to ensure the integrity of transactions. ARB has determined that the system would operate more efficiently if the administrator examined the transactions at the time of reporting rather than reviewing and possibly reversing the transactions at a much later date.

Summary of Section 95921(b).

Subsection (b) states the information that must be submitted along with each transaction report by account holders when they wish to transfer allowances between accounts.

Rationale for Section 95921(b).

The information requested allows the accounts administrator to determine that a valid transaction has taken place.

Summary of Section 95921(b)(1).

Subsection (b)(1) states that transaction reports must include the Holding Account number and name of the authorized account representative of the seller.

Rationale for Section 95921(b)(1).

The provision is needed because ARB must ensure that the person filing the transaction to sell a compliance instrument has the authority to do so. ARB will compare this information with the information supplied when the selling entity originally registered with ARB for an account.

Summary of Section 95921(b)(2).

Subsection (b)(2) states that transaction reports must include the Holding Account number and name of the authorized account representative of the buyer.

Rationale for Section 95921(b)(2).

The provision is needed because ARB must ensure that the person filing the transaction to buy a compliance instrument has the authority to do so. ARB will compare this information with the information supplied when the buying entity originally registered with ARB for an account.

Summary of Section 95921(b)(3).

Subsection (b)(3) states that the transaction report must include the serial numbers of the compliance instruments being transferred.

Rationale for Section 95921(b)(3).

The provision is needed because all tracking of transfers of compliance instruments is done through the serial number of the instrument.

Summary of Section 95921(b)(4).

Subsection (b)(4) states that the transaction report must include the date and time of the transaction agreement.

Rationale for Section 95921(b)(4).

The provision is needed because the accounts administrator needs to know when an agreement to transact was reached. so that it may maintain an accurate history of transfers.

Summary of Section 95921(b)(5).

Subsection (b)(5) states that the transaction report must include the date and time of the settlement of a transfer, if it is different than the date and time of the transaction agreement.

Rationale for Section 95921(b)(5).

The provision is needed because in some cases, parties to a trade may agree to transfer allowances at a future date, on terms specified in a contract. ARB will need to know when compliance instruments need to be transferred. For market monitoring purposes, ARB will need to know when instruments are being held in one account for the benefit of another entity. A *beneficial holding* means that someone other than the account holder may have ownership interest in the instrument.

Summary of Section 95921(b)(6).

Subsection (b)(6) states that the transaction report must include the price paid for the instrument.

Rationale for Section 95921(b)(6).

The provision is needed because ARB needs to know the prices paid for instruments in order to monitor market developments for potential manipulation or short supplies.

Summary of Section 95921(b)(7).

This subsection states that in cases where the buyer or seller are acting on behalf of a third party that has an ownership interest in the instrument, known as a beneficial holding, the transaction report must include the Holding Account number and name of the authorized representative of the entity with the ownership interest.

Rationale for Section 95921(b)(7).

The provision is needed because the accounts administrator must track the actual ownership interest in an instrument for market monitoring purposes. Some rules, such as the holding limit, are applied based on ownership rights, not only in whose account the instrument is located.

Summary of Section 95921(c).

Subsection states that the seller and buyer must report each transaction within three days of settlement of the transaction agreement.

Rationale for Section 95921(c).

The provision is needed because the accounts administrator needs to know when an agreement to transact was reached so that it may maintain an accurate history of transfers. If the reporting period is too long, additional transactions involving an instrument could take place before problems with previous transactions could be resolved.

Section 95922. Banking, Expiration, and Voluntary Retirement.

Summary of Section 95922(a).

Subsection (a) states that allowances issued by ARB or approved for use in California in the current year or a previous year may be held, or *banked,* by entities registered in the California cap-and-trade system.

Rationale for Section 95922(a).

The provision is needed because all those holding compliance instruments must be registered so that the accounts administrator can place the instruments in the correct account. For market monitoring purposes, ARB must know the identity of anyone holding instruments.

Summary of Section 95922(b).

Subsection (b) states that allowances issued by ARB or approved for use in California may be held by registered entities.

Rationale for Section 95922(b).

The provision is needed because all those holding compliance instruments must be registered so that the accounts administrator can place the instruments in the correct account. For market monitoring purposes, ARB must know the identity of anyone holding instruments. Unlike instruments issued for the current or previous year, there are restrictions in other parts of this regulation on the use of instruments issued for future compliance periods.

Summary of Section 95922(c).

Subsection (c) states that California compliance instruments do not have an expiration date. They remain valid until some action is taken by a registered entity to retire the allowance. This section provides a list of actions that may result in the retirement of an instrument by the Executive Officer. Once the retirement has been processed by the Executive Officer, the accounts administrator will prevent the instrument from appearing in another account in the system.

Rationale for Section 95922(c).

The provision is needed because ARB will allow account holders to hold allowances until they need them for compliance or voluntary retirement purposes.

Summary of Section 95922(c)(1).

Subsection (c)(1) states that an instrument will be removed from the tracking system when it is surrendered as part of a compliance obligation.

Rationale for Section 95922(c)(1).

The provision is needed to prevent double-counting. Once an instrument has been submitted for retirement, ARB must ensure that it cannot be transferred again between accounts on the system.

Summary of Section 95922(c)(2).

Subsection (c)(2) states that an instrument will be removed from the tracking system when it is voluntarily surrendered.

Rationale for Section 95922(c)(2).

The provision is needed to prevent double-counting. Once an instrument has been submitted for retirement, ARB must ensure that it cannot be transferred again between accounts on the system.

Summary of Section 95922(c)(3).

Subsection (c)(3) states that an instrument will be removed from the tracking system when it is surrendered within a GHG emissions-trading system with which the California cap-and-trade system has linked.

Rationale for Section 95922(c)(3).

To prevent double-counting, once a compliance instrument has been submitted for retirement, either in California or in a GHG emissions-trading system to which California has linked, ARB must ensure that it cannot be transferred again between accounts on the system.

Summary of Section 95922(d)(1).

Subsection (d)(1) states that a registered entity may voluntarily retire at any time any instrument it holds in its Holding Account.

Rationale for Section 95922(d)(1).

The provision is needed because entities without a compliance obligation may be interested in offsetting their emissions or contributing voluntarily to achieve program goals.

Summary of Section 95922(d)(2).

Subsection (d)(2) states that to voluntarily retire instruments, a registered entity simply files a transaction report with the accounts administrator listing the serial numbers of the instruments and the Retirement Holding Account controlled by the Executive Officer as the destination account.

Rationale for Section 95922(d)(2).

The provision is needed because ARB intends to keep the voluntary surrender process as simple as possible by having the entity involved use the standard transaction reporting process. The ARB Retirement Holding Account will have an account number like any other account.

Subarticle 12. Linkage to External Greenhouse Gas Emissions Trading Systems.

Section 95940. General Requirements.

Summary of Section 95940.

Section 95940 proposes that only approved compliance instruments issued by approved programs may be used for compliance in the cap-and-trade program.

Rationale for Section 95940.

This section is necessary to establish which types of compliance instruments issued by other programs may be approved for use under this article.

Section 95941. Procedures for Approval of External GHG ETS.

Summary of Section 95941.

Section 95941 proposes that the Board must approve each linkage after public notice and opportunity for public comment. In approving linkage, the Board will approve which compliance instruments issued by the program may be used for compliance.

Rationale for Section 95941.

This section is necessary to provide consistency among linked programs approved by the Board. This is ensured by requiring that the Board approves each program for linkage and determines that they meet the regulatory requirements.

Section 95942. Approval of Compliance Instruments from External GHG ETS.

Summary of Section 95942(a).

Subsection (a) proposes that once a linkage has been approved by the Board, the specified compliance instruments in Subarticle 12 can be used for compliance in this program.

Rationale for Section 95942(a).

This provision is necessary to ensure that compliance instruments issued by other programs can only be used for compliance once the Board has approved them at a programmatic level.

Summary of Section 95942(b).

Subsection (b) proposes that allowances issued by linked programs should not be subject to the quantitative usage limit specified in section 95855.

Rationale for Section 95942(b).

This provision provides that allowances issued by linked programs should not be subject to the quantitative limit on offsets because an allowance from a linked program is fungible in the same way that a California allowance is within the cap-and-trade system.

Summary of Section 95942(c).

Subsection (c) proposes that an offset credit or a sector-based credit issued by linked program should be subject to the quantitative usage limit specified in section 95855.

Rationale for Section 95942(c).

This provision provides that offset and sector-based credits issued by linked programs should be subject to the quantitative limit on offsets because California offsets and sector-based credits are also subject to this limit, and they should be treated equally.

Section 95943. Reserved for Linkage.

Summary of Section 95943.

Section 95943 is reserved as a placeholder for linkages approved by the Board in the future.

Rationale for Section 95943.

This section is necessary to ensure that provisions in the regulation are reserved to incorporate linkages that may be approved in the future, and to send a signal that California is serious about linking to programs in the future.

Subarticle 13. Offset Credits Issued by ARB.

Section 95970. General Requirements for Offset Credits Issued by ARB.

Summary of Section 95970.

Section 95970 establishes the requirements for an offset credit issued by ARB.

Rationale for Section 95970.

This section is necessary to show the requirements that an offset credit must meet to be issued by ARB. This section will help guide the reader through the credit issuance process.

Summary of Section 95970(a).

Subsection (a) requires that a greenhouse gas emission reduction be real, additional, quantifiable, permanent, verifiable, and enforceable.

Rationale for Section 95970(a).

Offset credits may only be issued for reductions that meet these qualities because Health and Safety Code section 38562(d)(1) states that these qualities are what constitute a greenhouse gas reduction. Since offset credits will be used in lieu of reducing emissions in California, those credits must be based on the same criteria.

Summary of Section 95970(b).

Subsection (b) limits offset credits' use to the limit set forth in section 95855.

Rationale for Section 95970(b).

This subsection is necessary because users of offset credits need to know the use of offset credits is limited. For justification of section 95855, please see above.

Summary of Section 95970(c).

Subsection (c) states that any offset credit issued must comply with protocols adopted by the Board.

Rationale for Section 95970(c).

This subsection is necessary because there are many different types of offset credits available, but not all of them meet the standards included in Board-adopted protocols. By including this section, ARB ensures that offset credits are subjected to uniform standards of integrity.

Summary of Section 95970(d).

Subsection (d) states that offset projects must meet the requirements of section 95973.

Rationale for Section 95970(d).

This subsection is necessary because there are many different offset projects. By including this section, ARB ensures that offset projects are subjected to uniform standards.

Summary of Section 95970(e).

Subsection (e) states that offset projects must be listed pursuant to requirements in section 95975.

Rationale for Section 95970(e).

This subsection is necessary to ensure that ARB has all the relevant information regarding offset projects using Board-approved protocols.

Summary of Section 95970(f).

Subsection (f) states that offset projects must meet the requirements for monitoring, reporting, and records retention.

Rationale for Section 95970(f).

This subsection is necessary because there are many different offset projects. By including this section, ARB ensures that offset projects are subjected to uniform requirements for monitoring, reporting, and record retention.

Summary of Section 95970(g).

Subsection (g) states that reductions from offset projects must meet the requirements for verification.

Rationale for Section 95970(g).

This subsection is necessary because there are many different offset projects. By including this section, ARB ensures that all reductions from offset projects are subjected to uniform requirements for verification.

Summary of Section 95970(h).

Subsection (h) states that offset credits must be issued according to sections 95980 and 95981.

Rationale for Section 95970(h).

This subsection is necessary because all offset credits issued under compliance offset protocols must meet the same requirements.

Summary of Section 95970(i).

Subsection (i) states that offset credits must be registered.

Rationale for Section 95970(i).

This subsection is necessary for ARB to track offset credits and the owners of offset credits at all times.

Section 95971. Procedures for Approval of Compliance Offset Protocols.

Summary of Section 95971.

Section 95971 establishes the process for how compliance offset protocols will be approved. Each compliance offset protocol must be approved by the Board after public notice and the opportunity for the public to submit comments. These protocols can then be used to generate offsets.

Rationale for Section 95971.

This section is necessary because the Board must determine if compliance offset protocols meet the criteria and requirements of this regulation for offset credits to be used for compliance purposes. It is also required by AB 32 that the Board adopt methodologies for the quantification of GHG emissions reductions (HSC § 38571) used for compliance purposes. Compliance offset protocols will be incorporated by reference in the regulation.

Section 95972. Requirements for Compliance Offset Protocols.

Summary of Section 95972(a).

Subsection (a) establishes the criteria that a compliance offset protocol must meet to be adopted by the Board.

Rationale for Section 95972(a).

This provision is necessary to provide consistency among compliance offset protocols that are adopted by the Board. Since each offset equals one metric ton of CO_2e, it is necessary that the rules governing the creation of offset credits are consistent.

Summary of Section 95972(a)(1).

Subsection (a)(1) requires that compliance offset protocols approved by the Board contain accurate quantification methods to determine the total number of GHG emission reductions or GHG removal enhancements.

Rationale for Section 95972(a)(1).

This provision is necessary because measurements and estimates associated with quantification must be as accurate as possible to ensure that GHG emissions reductions and GHG removal enhancements are real.

Summary of Section 95972(a)(2).

Subsection (a)(2) requires that compliance offset protocols approved by the Board contain monitoring procedures and processes for collecting data.

Rationale for Section 95972(a)(2).

Rules for monitoring procedures and data collection are essential for calculating the GHG emissions reductions or GHG removal enhancements that are controlled by the operator of the offset project.

Summary of Section 95972(a)(3).

Subsection (a)(3) requires that compliance offset protocols approved by the Board use a principle of conservativeness for estimating project baselines and business-as-usual emissions.

Rationale for Section 95972(a)(3).

To ensure GHG emissions reductions or GHG removal enhancements are real, the compliance offset protocol must contain factors that provide an accurate and realistic reflection of the project baseline and the business-as-usual (BAU) scenario.

Summary of Section 95972(a)(4).

Subsection (a)(4) requires that compliance offset protocols approved by the Board account for activity-shifting and market-shifting leakage.

Rationale for Section 95972(a)(4).

A compliance offset protocol must contain methods for leakage assessments to ensure that GHG emissions reductions and GHG removal enhancements are real. If leakage exists, emissions are displaced from one area to another and provide no net decrease in GHG emissions in the atmosphere.

Summary of Section 95972(a)(5).

Subsection (a)(5) requires that compliance offset protocols approved by the Board account for any uncertainties when quantifying GHG emission reductions or GHG removal enhancements.

Rationale for Section 95972(a)(5).

Compliance offset protocols must account for uncertainty to ensure that GHG emissions reductions or GHG removal enhancements are real. The greater the uncertainty in calculating GHG emissions reductions or GHG removal enhancements from project activities, the less confidence there is that all offsets generated by a project are real.

Summary of Section 95972(a)(6).

Subsection (a)(6) requires that compliance offset protocols approved by the Board ensure that GHG emission reductions are permanent.

Rationale for Section 95972(a)(6).

This provision is necessary to comply with Health and Safety Code section 38562(d)(1) that requires GHG reductions to be permanent.

Summary of Section 95972(a)(7).

Subsection (a)(7) requires that compliance offset protocols approved by the Board include mechanisms to ensure that GHG emissions reductions and GHG removal enhancements from sequestration offset projects are permanent.

Rationale for Section 95972(a)(7)

This provision is necessary if there is a risk of reversal, as is the case in most biological sequestration offset projects. In this case mechanisms must be in place to replace any reversed offset credits. Compliance offset protocols must include mechanisms to replace reversed offset credits to ensure permanence. Greenhouse gas emissions reductions and GHG removal enhancements credited as offsets must endure for a period of time, comparable to the atmospheric lifetime of anthropogenic CO_2 emissions, because the use of an offset allows a covered entity to emit one metric ton of CO_2e. If the offset credit is reversed while the emitted metric ton from the covered entity is still in the atmosphere, the atmospheric result is a net increase in GHG emissions.

Summary of Section 95972(a)(8).

Subsection (a)(8) requires that compliance offset protocols approved by the Board include the length of the crediting period.

Rationale for Section 95972(a)(8).

Compliance offset protocols must include the period of time a specific type of offset project is allowed to be issued compliance offset credits (the crediting period). The length of crediting periods may vary based on project type; therefore, ARB must include the length in the compliance offset protocol.

Summary of Section 95972(b), Crediting Periods.

Subsection (b) proposes a range for the length of crediting periods. The crediting period for non-sequestration projects is between 7 and 10 years and for sequestration-based projects between 10-30 years.

Rationale for Section 95972(b).

The length of a crediting period must be finite because ARB wants flexibility in the future to decide if certain offset project types are no longer valid for AB 32 compliance. This approach allows ARB to reevaluate and readjust project baseline and additionality requirements in the future if the regulatory environment changes and ARB determines offset projects are no longer additional. Staff proposes the range of 7 to 10 years for non-sequestration projects and 10 to 30 years for sequestration projects, to incentivize investment in these offset project types. Offset project developers need a guarantee of return on their investment. The most efficient way to do this is to establish a crediting period in which the emission reductions or removals from their projects will be eligible for compliance purposes.

Section 95973. Requirements for Offset Projects Using ARB Compliance Offset Protocols.

Summary of Section 95973(a), General Requirements for Offset Projects.

Subsection (a) establishes the requirements that offset projects must meet to be issued offset credits.

Rationale for Section 95973(a).

This provision is necessary to ensure that all offset projects meet the same criteria and are held to consistent standards.

Summary of Section 95973(a)(1).

Subsection (a)(1) proposes that all offset projects are required to use a compliance offset protocol, if the project wants to be issued offset credits.

Rationale for Section 95973(a)(1).

This provision is necessary to provide consistency among offset projects of the same type. Since each offset equals one metric ton of CO_2e, it is necessary that the rules governing the creation of offset credits are consistent. This can be achieved by requiring that all offset projects use the standardized compliance offset protocols.

Summary of Section 95973(a)(2).

Subsection (a)(2) proposes that all offset projects meet the same additionality requirements, and that additionality be assessed as of the date the offset project commences.

Rationale for Section 95973(a)(2).

This provision is necessary to provide consistency among offset projects of the same type. To ensure that each offset equals one metric ton of CO_2e, it is necessary that the rules for determining additionality are consistent for all offset projects.

Summary of Section 95973(a)(2)(A).

Subsection (a)(2)(A) proposes that GHG emissions reduction or GHG removal enhancement activities undertaken to comply with any federal, state, or local law, or regulation in the jurisdiction where the offset project is located, or would occur anyways under a conservative BAU scenario, not be eligible for offset credits.

Rationale for Section 95973(a)(2)(A).

This provision is necessary because AB 32 states that an emission reduction used for compliance purposes must be "in addition to any greenhouse gas emission reduction otherwise required by law or regulation, and any greenhouse gas emission reduction that otherwise would occur" (HSC §38562(d)(2)). Since offset projects can be located anywhere in North America, the laws and regulations applicable where the offset project is located will determine whether the project is additional.

Summary of Section 95973(a)(2)(B).

Subsection (a)(2)(B) proposes that an offset project must commence after December 31, 2006 to be considered additional.

Rationale for Section 95973(a)(2)(B).

This provision is necessary because establishing the eligibility date for an offset project is critical to determining if it is additional. December 31, 2006, reflects the implementation date of AB 32 and makes the bounds more clear for ARB to determine if an offset project was implemented to achieve AB 32 goals.

Summary of Section 95973(a)(2)(C).

Subsection (a)(2)(C) proposes that GHG emissions reductions and GHG removal enhancements must exceed the project baseline established in a compliance offset protocol to be considered additional. There are four protocols referenced in the regulation, and they include: U.S. Ozone Depleting Substances Projects

Protocol incorporated by reference date: October 2010; Livestock Manure (Digesters) Projects Protocol incorporated by reference date: October 2010; Urban Forest Projects Protocol incorporated by reference date: October 2010; and U.S. Forest Projects Protocol incorporated by reference date: October 2010.

Rationale for Section 95973(a)(2)(C).

This provision is necessary to ensure that GHG emissions reductions and GHG removal enhancements are additional. The project baseline reflects the conservative BAU scenario that would likely occur in the absence of the offset project. The offset project must prove that its emissions are less than the project baseline to receive offset credits. The number of offset credits each project receives is based on the difference of its measured emissions and the emissions in the BAU scenario.

Summary of Section 95973(a)(3).

Subsection (a)(3) proposes that offset projects must be located in the United States, Canada, or Mexico to be eligible to generate offset credits.

Rationale for Section 95973(a)(3).

This provision is necessary for ARB to have practical oversight over the offset projects that generate offsets. This geographic scope allows ARB to have oversight of its third-party verifiers, while also ensuring an ample supply of offsets. Limiting the geographic scope to only projects in California would not provide enough offset supply to meet total offset demand.

Summary of Section 95973(b), Local, Regional, and National Environmental Impact Assessment Requirements.

Subsection (b) proposes that an offset project meet all local, regional, and national requirements for environmental impact assessments that are applicable in its jurisdiction.

Rationale for Section 95973(b).

This provision is necessary to ensure that those responsible for offset projects are not implementing activities that do not comply with their local environmental laws and regulations.

Section 95974. Authorized Project Designee.

Summary of Section 95974(a), General Requirements for Designation of Authorized Project Designee.

Subsection (a) proposes to allow an operator of an offset project to give certain rights and responsibilities to a third party. Those responsible for an offset project

must say who these third parties are at the time they submit their project for listing.

Rationale for Section 95974(a).

This provision is necessary so ARB or an Offset Project Registry (OPR) knows which parties to contact when it issues offset credits or sends correspondence regarding an offset project.

Summary of Section 95974(a)(1).

Subsection (a)(1) proposes that an operator of an offset project can allow a third party to own the offset credits issued to its project, as long as the third party is allowed to hold compliance instruments.

Rationale for Section 95974(a)(1).

This provision is necessary because a landowner or project operator may have financial arrangements with third parties for the ownership of a project's offsets in which it invested. These third parties must be reported to ARB or an OPR so it knows which party to transfer the offset credits to.

Summary of Section 95974(a)(2).

Subsection (a)(2) proposes that an operator of an offset project can allow a third party to perform certain responsibilities associated with an offset project. These include: listing an offset project; monitoring, reporting and record retention; and verification.

Rationale for Section 95974(a)(2).

This provision is necessary because a landowner or project operator may contract with a third party to implement all or some aspects of their offset project on their behalf. These third parties must be reported to ARB or an OPR so it knows which party to contact regarding the offset project.

Summary of Section 95974(b), Modifications to Authorized Project Designee and Activities.

Subsection (b) proposes to allow an operator of an offset project to change and/or modify approved third parties or their approved activities once within each calendar year for a listed offset project.

Rationale for Section 95974(b).

This provision is necessary to allow operators of offset projects to conduct their private business and contracts as it wishes. Staff proposes to limit the number of

times an operator may do this to prevent any potential fraud or gaming of the program.

Section 95975. Listing of Offset Projects Using ARB Compliance Offset Protocols.

Summary of Section 95975(a), General Requirements for Offset Project Operators and Authorized Project Designees Who Are Submitting an Offset Project for Listing.

Subsection (a) proposes requirements that those responsible for an offset project must meet before an offset project can be listed.

Rationale for Section 95975(a).

This provision is necessary to ensure that ARB or an OPR has all the relevant information regarding those responsible for the offset project and details about the offset project itself.

Summary of Section 95975(a)(1).

Subsection (a)(1) proposes to require those responsible for an offset project to register with ARB, before an offset project that they are involved with is listed.

Rationale for Section 95975(a)(1).

This provision is necessary to ensure that ARB has all the relevant information regarding those responsible for the offset project. To hold compliance instruments, the party must register with ARB and open a Holding Account.

Summary of Section 95975(a)(2).

Subsection (a)(2) proposes that those responsible for an offset project may not be subject to any Holding Account restrictions, before an offset project that they are involved with is listed.

Rationale for Section 95975(a)(2).

This provision is necessary to ensure that those subject to a Holding Account restriction are not allowed to list or be involved with further offset projects.

Summary of Section 95975(a)(3).

Subsection (a)(3) proposes that the party responsible for listing an offset project must list their offset project with ARB or an OPR.

Rationale for Section 95975(a)(3).

This provision is necessary so that ARB or an OPR has all information related to the offset project if it intends to be issued offset credits.

Summary of Section 95975(b), General Requirements for Offset Project Listing.

Subsection (b) proposes that the party responsible for listing an offset project must make attestations and submit information related to the offset project to ARB or an OPR.

Rationale for Section 95975(b).

This provision is necessary to ensure that ARB or an OPR has all the relevant information regarding an offset project and that ARB has a legal and enforcement connection to those involved with offset projects.

Summary of Section 95975(b)(1).

Subsection (b)(1) proposes that the party responsible for listing an offset project attest to ARB that all information they submit to ARB or an OPR is complete and accurate.

Rationale for Section 95975(b)(1).

This provision is necessary to ensure that the information that the party responsible for listing the offset project submits is accurate and complete, and that ARB has a legal and enforcement connection to those involved with offset projects.

Summary of Section 95975(b)(2).

Subsection (b)(2) proposes that the party responsible for listing an offset project attest to ARB that they are subject to all regulatory requirements and enforcement mechanisms of the cap-and-trade program.

Rationale for Section 95975(b)(2).

This provision is necessary to ensure that the party responsible for listing the offset project acknowledges they are subject to all cap-and-trade regulatory and enforcement requirements and that ARB has a legal and enforcement connection to those involved with offset projects.

Summary of Section 95975(b)(3).

Subsection (b)(3) proposes to require the party responsible for listing an offset project to submit all documentation required to list an offset project in section 95975(c).

Rationale for Section 95975(b)(3).

This provision is necessary so that ARB or an OPR has all information related to the offset project and assess if the offset project may be eligible to be issued offset credits.

Summary of Section 95975(b)(4).

Subsection (b)(4) proposes that if an offset project is listed with an OPR, the attestations required in sections 95975(b)(1) and (b)(2) be submitted to ARB at the time of listing or when the party responsible of the offset project wishes to be issued ARB offset credits pursuant to section 95981(d)(1).

Rationale for Section 95975(b)(4).

This provision is necessary to ensure that the information that the party responsible for listing the offset project submits is accurate and complete, and that ARB has a legal and enforcement connection to those involved with offset projects.

Summary of Section 95975(c), Offset Project Listing Information Requirements.

Subsection 95975(c) proposes that the party responsible for listing an offset project submit all the listing information required in a compliance offset protocol. There are four protocols referenced in the regulation and they include: U.S. Ozone Depleting Substances Projects Protocol incorporated by reference date: October 2010; Livestock Manure (Digesters) Projects Protocol incorporated by reference date: October 2010; Urban Forest Projects Protocol incorporated by reference date: October 2010; and U.S. Forest Projects Protocol incorporated by reference date: October 2010.

Rationale for Section 95975(c).

This provision is necessary so that the party responsible for listing an offset project knows what information and documentation they must submit to ARB or an OPR for their project to be listed.

Summary of Section 95975(d), Notice of Completeness for Offset Project Listing Information.

Subsection (d) proposes that ARB or an OPR notify the party responsible for listing an offset project that all listing information is complete and the offset project may be listed. If the information submitted is incomplete, the party responsible for listing an offset project will also be notified of what is deficient.

Rationale for Section 95975(d).

This provision is necessary so the party responsible for listing an offset project knows that ARB or an OPR has received their listing information and that it can be processed for listing. If it is not complete, they will be told why and be given the opportunity to submit the correct and complete information.

Summary of Section 95975(e), Timing for Offset Project Listing in an Initial Crediting Period.

Subsection (e) proposes that the party responsible for listing an offset project in an initial crediting period submit its listing information no later than when it submits its monitoring and reporting data, as required in section 95976, to ARB or an OPR.

Rationale for Section 95975(e).

This provision is necessary to ensure that ARB or an OPR has listed an offset project before it begins accepting monitoring and reporting data for the offset project in an initial crediting period.

Summary of Section 95975(f), Listing Status of Offset Projects in an Initial Crediting Period.

Subsection (f) proposes that once the party responsible for listing an offset project in an initial crediting period submits its listing information, and ARB or an OPR has reviewed the information against the requirements for additionality, it will be listed as a "Proposed Project." This subsection also proposes that if an OPR denies the listing of an offset project in an initial crediting period, the party responsible for the offset project may request ARB to make a final decision as to whether or not the offset project meets the requirements for listing.

Rationale for Section 95975(f).

This provision is necessary so that all offset projects listed by ARB or an OPR in an initial crediting period are reviewed against the same requirements for additionality. A more in-depth analysis of additionality will be performed by an ARB-accredited third-party verifier. The project will be listed as a "proposed project" for transparency purposes on a publicly available website. The project is considered a "proposed project" at this time because it has not yet received a positive offset or qualified positive offset verification statement. This section is necessary so ARB can have the final determination as to whether an offset project meets the requirements for listing in an initial crediting period.

Summary of Section 95975(g), Timing for Offset Project Listing in a Renewed Crediting Period.

Subsection (g) proposes that the party responsible for listing an offset project in a renewed crediting period submit its listing information no earlier than 18 months before the conclusion of its initial crediting period or a previous renewed crediting period, and no later than 9 months before conclusion of its initial crediting period or a previous renewed crediting period.

Rationale for Section 95975(g).

This provision is necessary to establish a range of time in which additionality will be assessed for offset projects seeking a renewed crediting period.

Summary of Section 95975(h), Listing Status of Offset Projects in a Renewed Crediting Period.

Subsection (h) proposes that once the party responsible for listing an offset project in a renewed crediting period submits its listing information, and ARB or an OPR has reviewed the information against the requirements for additionality as of the date the renewed crediting period begins, it will be listed as a "Proposed Renewal." This subsection also proposes that if an OPR denies the listing of an offset project in renewed crediting period, the party responsible for the offset project may request ARB to make a final decision as to whether or not the offset project meets the requirements for listing. This section is necessary so ARB can have the final determination as to whether an offset project meets the requirements for listing in an initial crediting period.

Rationale for Section 95975(h).

This provision is necessary so that all offset projects listed by ARB or an OPR in a renewed crediting period are reviewed against the same requirements for additionality. A more in-depth analysis of additionality will be performed by an ARB-accredited third-party verifier. The project will be listed as a "proposed renewal" for transparency purposes on a publicly available website. The project is considered a "proposed renewal" at this time, because it has not yet received a positive or qualified positive verification statement in its renewed crediting period.

Summary of Section 95975(i), Limitations for Crediting Period Renewals.

Subsection (i) proposes that an offset project's crediting period may be renewed if it meets the requirements for additionality.

Rationale for Section 95975(i).

This provision is necessary to allow offset projects that meet the additionality criteria for a period of time to continue to reduce GHG emissions. A renewed

crediting period also allows for ARB to reevaluate the offset project's baseline and additionality before it can be renewed.

Summary of Section 95975(i)(1).

Subsection (i)(1) proposes that a non-sequestration offset project may be renewed twice, for the length of the crediting period that is specified in a compliance offset protocol.

Rationale for Section 95975(i)(1).

This provision is necessary to allow non-sequestration projects to be renewed. The period of time represented by the total renewal periods represents the length of time that staff believes these types of offset projects will continue to be additional. Crediting periods may be renewed to continue to allow offset projects to generate offset credits, as long as they continue to meet the eligibility requirements for offset projects.

Summary of Section 95975(i)(2).

Subsection (i)(2) proposes that a sequestration offset project may be renewed for a total of 100 years, regardless of the length of the crediting period that is specified in a compliance offset protocol.

Rationale for Section 95975(i)(2).

This provision is necessary to allow sequestration offset projects to be renewed. The period of time represented by the total renewal periods represents the length of time that staff believes these types of offset projects will continue to be additional and will continue to store carbon. Crediting periods for sequestration offset projects may be renewed as long as they continue to meet the eligibility requirements for offset projects, because they require long-term investment and commitment by project developers and achieve gradual GHG removals over long timescales.

Section 95976. Monitoring, Reporting, and Record Retention Requirements for Offset Projects.

Summary of Section 95976.

Section 95976 provides the monitoring, reporting, and record retention requirements for offset project.

Rationale for Section 95976.

This provision is needed to provide enforceable monitoring, reporting, and record retention requirements, to provide consistent and accurate information to ARB

and for program transparency. The document retention requirements will support verification and ARB audits of the project.

Summary of Section 95976(a).

Subsection (a) specifies that equipment used to monitor emissions from offset projects must be maintained and calibrated as required by the manufacturer at the level of accuracy stated in the Compliance Offset Protocol. Other measurements must be consistent with the applicable offset protocol.

Rationale for Section 95976(a).

This provision is needed to ensure accurate accounting of project related emissions data. It is necessary to specify basic requirements for the accuracy and measurement of GHG emissions for consistence in data quality across all offset projects.

Summary of Section 95976(b).

Subsection (b) requires any applicable missing data provisions in each Compliance Offset Protocol to be followed by the project developer.

Rationale for Section 95976(b).

This provision is necessary to ensure that those developing offset projects of the same project type are held to the same standard when accounting for missing data. Some Compliance Offset Protocols may offer these methods when there is a requirement for continuous monitoring of project performance.

Summary of Section 95976(c).

Subsection (c) requires that all monitoring equipment must be installed as specified in each Compliance Offset Protocol. Each Compliance Offset Protocol contains specific monitoring requirements to support quantification of GHG reductions or GHG removals.

Rationale for Section 95976(c).

This provision is necessary to ensure that those developing offset projects are correctly installing the required monitoring equipment specific to each project type. It is important to have the correct monitoring equipment to accurately quantify baseline emissions, project emissions, GHG removals, and GHG reductions.

Summary of Section 95976(d).

Subsection (d) requires those developing an offset project to submit an Offset Project Data Report to ARB or an OPR for a calendar year.

Rationale for Section 95976(d).

This provision is necessary to have annual reporting of data for offset projects that may be eligible to be issued offset credits by ARB. This data also provides transparency in the program, as all stakeholders will be able to see a public report on the performance of each offset project.

Summary of Section 95976(d)(1) through (d)(4).

Subsections (d)(1) through (d)(4)require those developing offset projects to annually submit the types of data for each project provided in the applicable Compliance Offset Protocol to ARB or an OPR.

Rationale for Section 95976(d)(1) through (d)(4).

These subsections are needed for program transparency, as the information will be made available to all stakeholders, and to ensure a consistent level of reporting between project types.

Summary of Section 95976(d)(5).

Subsection (d)(5) requires those developing offset projects to attest to ARB that the information provided in the Offset Project Data Report is accurate and complete.

Rationale for Section 95975(d)(5).

This provision is necessary to ensure that the information that the party responsible for submitting the Offset Project Data Report is accurate and complete and that ARB has a legal and enforcement connection to those involved with offset projects.

Summary of Section 95975(d)(6).

Subsection (d)(6) requires all Offset Project Data Reports covering the previous year of reporting to be submitted by an April 1 deadline. For sequestration projects, there are still annual reports, but GHG removals may be aggregated into an annual report to cover up to six years of GHG removals.

Rationale for Section 95975(d)(6).

This subsection is necessary to provide timely and consistent flow of data for the transparency of the program. Sequestration projects take a long time to sequester carbon, and it makes sense to allow those developing offset projects to report multiple years of GHG removals, by year, on a single report. During verification of that annual report, all GHG removals for each year would be verified at the same time, thus making it more cost-effective for those developing offset projects.

Summary of Section 95975(d)(7).

Subsection (d)(7) states that any Offset Project Data Reports that are not submitted covering the project performance for the previous year are ineligible to receive ARB offset credit for the GHG removals or GHG reductions quantified and reported in that report.

Rationale for Section 95975(d)(7).

This provision is necessary to help enforce the reporting deadline of April 1. Participation in the compliance offset program is voluntary, and this provides a mechanism to ensure that all data required for an offset project is provided in a timely manner for program transparency, and for compliance entities to be aware of the types and amounts of compliance instruments they may be able to use.

Summary of Section 95976(e).

Subsection (e) requires those developing offset projects to retain all information used to develop the Offset Project Data Report, including documentation of the project boundary, fuel usage, model inputs, and other descriptions of the project. Specific document type retention requirements are included.

Rationale for Section 95976(e).

This provision is necessary to provide careful documentation that allows for the verification of the Offset Project Data Report by a verification body and also allows for any audits by ARB.

Summary of Section 95976(e)(1).

Subsection (e)(1) provides a detailed list of the types of documentation those developing an offset project must retain for their offset project.

Rationale for Section 95976(e)(1).

This provision is necessary so that all project-relevant data is maintained to support a successful verification of the offset project and for ARB to review as part of its offset project auditing. This list provides a consistent requirement for all data retention across all offset projects.

Summary of Section 95976(e)(2).

Subsection (e)(2) specifies the length of project related data document retention, that they must be able to support verification, and that the documents must be made available to ARB or an OPR if requested.

Rationale for Section 95976(e)(2).

This provision is necessary to ensure that ARB or an OPR has access to the documents even after a crediting period has ended, in case a problem is found with the offset project.

Summary of Section 95976(e)(3)

Subsection (e)(3) specifies that documents required for retention must be extensive enough for verification of each Offset Project Data Report.

Rationale for Section 95976(e)(3)

This provision is necessary to ensure that ARB or an OPR will have enough data to confirm the crediting project has been operating in accordance with the appropriate ARB-approved protocol.

Summary of Section 95976(e)(4)

Subsection (e)(4) specifies that entities that operate an offset project must provide all documents required to be retained pursuant to the regulation within ten days to either ARB or an Offset Project Registry.

Rationale for Section 95976(e)(4)

This provision is necessary so that ARB or an Offset Project Registry can conduct an audit of the offset project to ensure the offset project is complying with all provisions of the appropriate ARB-approved protocol.

Summary of Section 95976(f), General Procedure for Interim Gas or Fuel Analytical and Monitoring Equipment Data Collection.

Section 95975(f) provides a process for those developing an offset project to make a request to ARB for an alternate method to monitor project data if there is a breakdown in the existing monitoring equipment. The proposed method must meet criteria to demonstrate it will provide accurate data to support any project-related calculations.

Rationale for Section 95976(f).

This provision is necessary because in the real world, sometimes monitoring equipment may break down. This provision provides some flexibility to those developing an offset project to propose an alternative monitoring method, so that the project may continue to accurately generate data for offset credits.

Summary of Section 95976(f)(1).

Subsection (f)(1) provides the conditions under which those developing an offset project may request an interim data collection method. Those criteria include a threshold of 20 percent missed data, hardship in fixing the failed monitoring equipment, and that the request must be made within 30 days of monitoring equipment failure.

Rationale for Section 95976(f)(1).

This provision is needed to apply the interim data collection method only in very limited circumstances. Those developing an offset project must be diligent in their own maintenance and implementation of their offset projects. However, even under the best maintenance plans, there can be unforeseen problems, and this provision is to provide recourse to those developing an offset project in those cases.

Summary of Section 95976(f)(2).

Subsection (f)(2) provides the process and information that those developing an offset project must meet to request an interim data collection method.

Rational for Section 95976(f)(2).

This provision is needed to ensure that ARB has all of the relevant information on which to make a decision on whether or not to approve a request for an interim data collection method.

Summary of Section 95976(f)(3).

Subsection (f)(3) provides ARB the right to limit the duration of the interim data collection method or request additional information before making a determination on a interim data collection method request.

Rationale for Section 95976(f)(3).

This provision is needed to require that those developing an offset project expeditiously fix the issue with their monitoring equipment and return to collecting data, as required under the applicable Compliance Offset Protocol. The interim data collection method is meant to only be used for a limited time, until the protocol requirements for monitoring may be restarted. Additional information may be needed to fully understand the extent of the equipment failure and the time needed to repair it.

Summary of Section 95976(f)(4).

Subsection (f)(4) stipulates how ARB will treat the data collected under an interim data collection method.

Rationale for Section 95976(f)(4).

This provision is necessary for verifiers and those developing an offset project to understand how to treat data that is not collected as required in a Compliance Offset Protocol. Data collected under an interim method is considered captured data, and ARB will determine its treatment during the verification assessment for material misstatement.

Section 95977. Verification of GHG Emission Reductions or GHG Removal Enhancements from Offset Projects.

Summary of Section 95977.

Section 95977 includes general verification requirements for those developing offset projects that submit Offset Project Data Reports.

Rationale for Section 95977.

This section is necessary because AB 32 requires any offset credits used for compliance to be subject to regulatory verification.

Summary of Section 95977(a), General Requirements.

Subsection (a) requires all Offset Project Data Reports to be verified by an ARB-accredited verification body.

Rationale for Section 95977(a).

This provision is necessary to ensure that only ARB-accredited verification bodies that meet certain regulatory criteria provide verification services to the those developing offset projects.

Summary of Section 95977(b), Schedule of Verification Services of Non-Sequestration Projects.

Subsection (b) specifies that verification must be done annually for non-sequestration projects (such as digesters).

Rationale for Section 95977(b).

This provision is necessary because annual verification follows annual reporting of Offset Project Data Reports. This facilitates a scheduled stream of potential offsets for non-sequestration projects. Annual verification provides a dependable schedule for stakeholders to understand the supply of offsets in the compliance program.

Summary of Section 95977(c), Schedule of Verification of Sequestration Projects.

Subsection (c) specifies that verification must be done at least once every six years for sequestration projects (such as forestry).

Rationale for Section 95977(c).

This provision is necessary because sequestration projects sequester incremental amounts of carbon per year, it is acceptable to decrease the frequency of verification from annually to at least once every six years. This allows enough carbon to be sequestered and potentially issued credits to make verification cost-effective.

Summary of Section 95977(d), Timing of Submittal of Offset Verification Statements to ARB or an OPR.

Subsection (d) specifies that verification reports must be submitted by October 1.

Rationale for Section 95977(d).

This provision is necessary to provide a consistent date for Offset Project Data Reports to be verified and issued credits each year.

Summary of Section 95977(e)(1), Rotation of Verification Bodies.

Subsection (e)(1) specifies that verification bodies and verifiers may only work for those developing offset projects for six consecutive years before rotating to a different verification body.

Rationale for Section 95977(e)(1).

This provision is necessary because rotation of verification bodies requires an entirely new verification team to evaluate the emissions data report, to minimize any biases and avoid familiarity or complacency between those developing offset projects and the verification body.

Summary of Section 95977(e)(2)(A), Notice of Verification Services.

Subsection (e)(2)(A) specifies the information that must be provided in the Notice of Verification Services submittal requirement for offset projects. The notice is also sent to an OPR, if applicable.

Rationale for Section 95977(e)(2)(A).

This provision is needed to ensure that the verification body provides information to identify a verification team with any applicable project specialists and that ARB or an OPR has an opportunity to plan to observe the site visit as part of an audit during oversight of its regulatory verification program.

Summary of Section 95977(e)(2)(B).

Subsection (e)(2)(B) requires the verification body to update the information provided in the Notice of Verification Services.

Rationale for Section 95977(e)(2)(B).

This provision is necessary for ARB to have accurate documentation of the team members that actually provided verification services for a facility, to ensure rotation of verification bodies and verifiers. The updated information on site visits will allow ARB staff to make any changes necessary in their schedule if the verification was previously chosen for an audit.

Summary of Section 95977(e)(2)(C)(i), Verification Plan for Offsets.

Subsection (e)(2)(C)(i) requires the verification team to obtain information from those developing offset projects to develop a verification plan.

Rationale for Section 95977(e)(2)(C)(i).

This provision is necessary to ensure that all verification teams request consistent and similar information to develop a verification plan. The verification plan is needed to define the scope and timing of verification services for a client.

Summary of Section 95977(e)(2)(C)(ii).

Subsection (e)(2)(C)(ii) contains lists the minimum requirements for what a verification plan should include for all verifications.

Rationale for Section 95977(e)(2)(C)(ii).

This provision is needed to ensure consistency for all verification plans and provides a written record as to what the verification team will do as part of verification, as well as the expected dates of completion.

Summary of Section 95977(e)(2)(C)(iii).

Subsection (e)(2)(C)(iii) requires the verification team to explain the scope of verification services to the client and review original documentation as part of providing verification services.

Rationale for Section 95977(e)(2)(C)(iii).

This provision is needed to ensure that the verification team communicates its planned activities for verification services to those developing offset projects and that original documentation is reviewed, to limit the opportunity of fraud by those developing offset projects. It is important for those developing offset projects to understand the verification process so that they can be prepared to provide information to the verification team.

Summary of Section 95977(e)(2)(C)(iv)(a), Site Visits for Offset Projects.

Subsection (e)(2)(C)(iv)(a) requires the verification team to make a site visit to each offset project site when they are verifying GHG emission reductions or GHG removals. While on site the verification team must conduct an array of activities to confirm the eligibility of the offset project and an accurate project boundary, review project monitoring techniques, and confirm that all of the monitoring and measuring requirements are in conformance. The requirements in this section only have to be checked the first year of the offset project verification, as it is unlikely they will change year to year.

Rationale for Section 95977(e)(2)(C)(iv)(a).

This provision is needed to validate the offset project. The check on the eligibility requirements is often a separate validation step. ARB has combined this step into the first year of verification to streamline the offset project program. This check reassures those developing offset projects that their projects are set up to conform to the applicable Compliance Offset Protocol.

Summary of Section 95977(e)(2)(C)(iv)(b).

Subsection (e)(2)(C)(iv)(b) requires the verification team to review the sources and sinks in the project boundary and review all equipment and data systems that are collecting or processing offset project-related data. It also requires the verification to ensure that the offset project meets all environmental laws. If the offset project does not meet all applicable environmental laws, it is ineligible to receive ARB offset credit.

Rationale for Section 95977(e)(2)(C)(iv)(b).

This provision is necessary to ensure that the offset project continues to operate in accordance with the Compliance Offset Protocol, so that all reported GHG reductions or GHG removals are accurately quantified. It also ensures that the offset project continues to be implemented in a manner that does not adversely affect the environment.

Summary of Section 95977(e)(2)(C)(v).

Subsection (e)(2)(C)(v) requires the verification team to review the offset project to ensure that all sources and sinks are included in the Offset Project Data Report.

Rationale for Section 95977(e)(2)(C)(v).

This provision is necessary to ensure the verification team take stock of all the GHG emission sources and sinks that are required to be included in the Offset Project Data Report for the applicable Compliance Offset Protocol. This ensures completeness of reporting for the project and accounts for any sources impacted by the offset project.

Summary of Section 95977(e)(2)(C)(vi).

Subsection (e)(2)(C)(vi) requires those developing offset projects to provide all offset project-related data to the verification team.

Rationale for Section 95977(e)(2)(C)(vi).

This provision is necessary to ensure that verification teams have access to all of the information related to an offset project during verification. If a verification team could not corroborate the data in the Offset Project Data Report with underlying data or other sources of information, they would have to submit an adverse offset verification statement.

Summary of Section 95977(e)(2)(C)(vii), Sampling Plan for Offset Project Data Reports.

Subsection (e)(2)(C)(vii) requires the verification team to develop a sampling plan that ranks the sources, sinks, and reservoirs by their relative contribution to the emissions of the offset project, and by their risk of uncertainty in quantification. The risk of uncertainty is based on the verification team's assessment of document reviews, data collection and management systems, and the general diligence of those developing offset projects in maintaining the project and all related systems.

Rationale for Section 95977(e)(2)(C)(vii).

This provision is necessary to isolate the GHG sources, sinks, or reservoirs that will be targeted for a more in-depth review by the verification team. During the course of verification services, the verification team does not recalculate the entire accounting and inventory of GHGs in the Offset Project Data Report. Greenhouse gas verification is a risk-based review of a GHG assertion in international standards. The development of a sampling plan facilitates a risk-based review of the Offset Project Data Report.

Summary of Section 95977(e)(2)(C)(viii).

Subsection (e)(2)(C)(viii) requires the verification team to identify the specific GHG sources, sinks, or reservoirs that will be subject to data checks and review for conformance. The verification team must document the information reviewed for these sources.

Rationale for Section 95977(e)(2)(C)(viii).

This provision is necessary to document the verification process, to enable ARB audits and to ensure that the verification team has conducted its due diligence in its data checks. The use of data checks is based on international best practices for GHG verification. This also provides a consistent requirement for all verifications and provides program consistency.

Summary of Section 95977(e)(2)(C)(ix).

Subsection (e)(2)(C)(ix) requires the sampling plan to be updated prior to the completion of verification services.

Rationale for Section 95977(e)(2)(C)(ix).

This provision is necessary because during the course of verification, the verification team may uncover information that requires them to look more closely at something not contained in the original sampling plan. An updated sampling plan provides a written record of the verification process, to allow for ARB audits.

Summary of Section 95977(e)(2)(C)(x).

Subsection (e)(2)(C)(x)requires the verification team to continuously revise the sampling plan as evidence becomes available.

Rationale for Section 95977(e)(2)(C)(x).

This provision is necessary to ensure that the verification team is diligent in its recording of information during the course of providing verification services. All findings during the verification services must be recorded to support ARB audits and transparency in the performing of verification services upon which the verification team forms its findings.

Summary of Section 95977(e)(2)(C)(xi).

Subsection (e)(2)(C)(xi)provides the document and data retention requirements for verification bodies.

Rationale for Section 95977(e)(2)(C)(xi).

This provision is necessary to ensure that all verification-related information is retained to enable ARB audits, and that there is a clear, documented evidence upon which a verification body made its findings when it issued an Offset Verification Statement.

Summary of Section 95977(e)(2)(C)(xii).

Subsection (e)(2)(C)(xii) specifies which data checks must be performed by the verifier, including the evaluation of methods and factors, emission sources, and other Compliance Offset Protocol requirements.

Rationale for Section 95977(e)(2)(C)(xii).

This provision is necessary to define data checks so that all verification bodies are held to the same standards when completing Offset Verification Services. A clear listing of requirements provides some certainty to both those developing

offset projects and verifiers as to how data checks must be completed. Data checks are critical in a risk-based assessment for Offset Material Misstatement and conformance.

Summary of Section 95977(e)(2)(C)(xiii).

Subsection (e)(2)(C)(xiii) requires those developing offset projects to fix any errors in the Offset Project Data Report, if possible.

Rationale for Section 95977(e)(2)(C)(xiii).

This provision is necessary because in a cap-and-trade program, it is necessary to have the data as accurate as possible.

Summary of Section 95977(e)(2)(C)(xiv).

Subsection (e)(2)(C)(xiv) requires verifiers to conduct their own calculations of sources that were identified as having high risk for potential error in the sampling plan and to review the calculations of the GHG emissions or GHG reductions for those sources for conformance with the regulation or applicable Compliance Offset Protocol.

Rationale for Section 95977(e)(2)(C)(xiv).

This provision is necessary so that all verifiers are held to a consistent standard that requires them to recalculate emissions sources for select sources and review those same sources for conformance. A verifier's recalculation of the GHG sources, sinks, or reservoirs provides a comparison for what the verifier believes should be the number based on the Compliance Offset Protocol versus what those developing an offset project included in the Offset Project Data Report. This process is based on international best practices for GHG verification.

Summary of Section 95977(e)(2)(C)(xv).

Subsection (e)(2)(C)(xv) specifies how the log of issues is developed by the verifier, and how the verifier must describe the impact of any identified issues on the Offset Verification Statement.

Rationale for Section 95977(e)(2)(C)(xv).

This provision is necessary because the log of issues is required to ensure that those developing offset projects understand how each of the identified issues could impact the Offset Verification Statement, helping to ensure a transparent process between the verification body and those developing offset projects. The issues log can also inform ARB as to any problems discovered during the course of verification.

Summary of Section 95977(e)(2)(C)(xvi) through (e)(2)(C)(xvii).

Subsections (e)(2)(C)(xvi) through (e)(2)(C)(xvii) describe when and how an Offset Material Misstatement is evaluated, including an equation that relates the errors and omissions to the accuracy of the reported data.

Rationale for Section 95977(e)(2)(C)(xvi) through (e)(2)(C)(xvii).

These provisions are necessary because a single equation for Offset Material Misstatement ensures that all verifiers are consistently evaluating emissions for each project using the same calculation. Without a consistent method, verifiers may reach different conclusions when reviewing the same data. This equation is rooted in financial auditing and is consistent with other regulatory or voluntary offset verification programs.

Summary of Section 95977(e)(2)(C)(xviii)(a), Offset Verification Statement.

Subsection (e)(2)(C)(xviii)(a) requires the verification body to prepare an Offset Verification Statement that documents the findings for the verification of the Offset Project Data Report, and that those findings are independently reviewed within the verification body.

Rationale for Section 95977(e)(2)(C)(xviii)(a).

This provision is necessary to bring the verification process to a close, provide findings, and have internal verification body checks on those findings as a quality control/quality assurance (QC/QA) measure on the services provided by the verification body.

Summary of Section 95977(e)(2)(C)(xviii)(b).

Subsection (e)(2)(C)(xviii)(b) requires an independent reviewer to review key decisions made by the verification body during the course of verification services.

Rationale for Section 95977(e)(2)(C)(xviii)(b).

This provision ensures that the independent reviewer focus on key points that could easily affect the outcome of a verification and provide a check on decisions made by the verification team at those critical points.

Summary of Section 95977(e)(2)(C)(xviii)(c).

Subsection (e)(2)(C)(xviii)(c) requires the independent reviewer to remain completely out of the verification process until they objectively review the verification teams findings. The independent reviewer also confirms that the verification team met all of its obligations under the regulation when providing verification services.

Rationale for Section 95977(e)(2)(C)(xviii)(c).

This provision is necessary to ensure that even within the verification body, there truly is an objective review of the verification team's findings before an Offset Verification Statement is issued for the Offset Project Data Report. The verification body takes responsibility for the work of its staff under the regulation and must be sure that it has met all of the requirements of the regulation before submitting the Offset Verification Statement. The concept of an internal review is also consistent with international best practices for GHG verification.

Summary of Section 95977(e)(2)(C)(xviii)(d).

Subsection (e)(2)(C)(xviii)(d) requires the verification team to compile a detailed verification report of key documents developed during the verification process, include in the verification statement whether or not the Offset Project Data Report contains an Offset Material Misstatement, and whether or not the report conforms to the regulation and applicable Compliance Offset Protocol. The lead verifier on the verification team must attest that all information provided in the Offset Verification Statement is accurate and complete, and that all verification requirements have been met.

Rationale for Section 95977(e)(2)(C)(xviii)(d).

This provision is necessary to ensure those developing offset projects understand the verification process and findings that led to the Offset Verification Statement. It also ensures the verification body compiles a final report of all the evidence that supports the Offset Verification Statement. This report can also provide information to ARB during an audit, to ensure consistency and quality of its verification program. The attestation statement holds the lead verifier for the verification accountable to ARB for the findings in the Offset Verification Statement.

Summary of Section 95977(e)(2)(C)(xix).

Subsection (e)(2)(C)(xix) requires the verification body to provide those developing offset projects with 10 working days in which to modify the Offset Project Data Report if the those developing offset projects are about to receive an Adverse Offset Verification Statement. This section also describes the process for ARB or an OPR to review the Offset Verification Statement and provide a final resolution to any dispute issues that cannot be resolved between the verification body and those developing offset projects. If those developing offset projects are not satisfied by a review provided by the OPR, they may appeal to ARB to conduct a second review.

Rationale for Section 95977(e)(2)(C)(xix).

This provision provides those developing offset projects with 10 working days to modify and correct the Offset Project Data Report and provides enough time for

those developing offset projects to make the necessary changes to the report, while balancing the need to complete the verification in a timely fashion. The dispute resolution process provides a mechanism for the verification body and those developing offset projects to have an Offset Project Data Report reviewed under certain circumstances before an Offset Verification Statement is issued.

Summary of Section 95977(e)(2)(C)(xx).

Subsection (e)(2)(C)(xx) states that no changes may be made to Offset Project Data Reports after an Offset Verification Statement has been submitted to ARB.

Rationale for Section 95977(e)(2)(C)(xx).

This provision is necessary in a cap-and-trade program so that ARB can issue offset credit to verified GHG reductions or removals. Verified data is considered accurate and complete as it has been through the verification process and subject to scrutiny by an independent eye. ARB does not anticipate those developing offset projects needing to change their data after the completion of verification.

Summary of Section 95977(e)(2)(C)(xxi).

Subsection (e)(2)(C)(xxi) specifies that if a high conflict is discovered, the Offset Project Data Report must be re-verified by a different verifier.

Rationale for Section 95977(e)(2)(C)(xxi).

This provision is necessary because a verification body that contracts with those developing offset projects within one year of submitting an Offset Verification Statement in order to provide a high-conflict service may not have provided an independent and unbiased Offset Verification Statement. It is necessary to invalidate any verification where there is an identified high conflict of interest, and that verification body may have their accreditation revoked in response to that activity. Because it is important to ensure the Offset Verification Statement is provided by an unbiased verifier, any high conflicts discovered during or after verification triggers re-verification so that the accuracy of the report can be assessed by a truly independent verifier.

Summary of Section 95977(e)(2)(C)(xxii).

Subsection (e)(2)(C)(xxii) requires those developing offset projects to provide ARB with all data available to the verifier for review by ARB staff.

Rationale for Section 95977(e)(2)(C)(xxii).

This provision is necessary because in order for ARB to have effective oversight of the program and to audit reports, ARB staff must have access to all data used to develop the Offset Project Data Report. ARB must be able to request all

project-related data in order to ensure Offset Project Data Reports are accurate and complete.

Summary of Section 95977(e)(2)(C)(xxiii).

Subsection (e)(2)(C)(xxiii) requires the verification body to provide ARB with a detailed verification report.

Rationale for Section 95977(e)(2)(C)(xxiii).

This provision is necessary because for ARB to evaluate the work of verification bodies, it is necessary to review and audit their detailed verification reports.

Summary of Section 95977(e)(2)(C)(xxiv).

Subsection (e)(2)(C)(xxiv) requires a verification body to make itself available for ARB audit.

Rationale for Section 95977(e)(2)(C)(xxiv).

This provision is necessary because for ARB to have effective oversight of the program, ARB may need to audit verification bodies and verifiers to evaluate the quality of verification services provided under this section.

Summary of Section 95977(f)

Subsection (f) requires that offset projects must meet both the verification requirements of the regulation as well as any additional verification requirements of the specific Compliance Offset Protocol, if any.

Rationale for Section 95977(f)

This provision is necessary to ensure that all offset projects comply with both the regulation and any project specific verification requirements. The verification requirements are necessary to ensure that GHG reductions reported are actually occurring.

Section 95978. Offset Verifier and Verification Body Accreditation.

Summary of Section 95978.

Section 95978 requires offset project verifiers and verification bodies to meet the requirements in Subarticle 4, section 95132 of the Mandatory Reporting Regulation.

Rationale for Section 95978.

This section is necessary so all verifiers and verification bodies providing verification services under the mandatory reporting program or offset program

will be held to the same rigorous standards for accreditation. These standards are based on existing accreditation requirements in other voluntary and regulatory GHG reporting and offset programs. The requirements are also consistent with international best practices for verification body accreditation.

Section 95979. Conflict of Interest for Verification Bodies for Verification of Offset Project Data Reports.

Summary of Section 95979(a).

Subsection (a) stipulates that the conflict-of-interest requirements apply to each verification body and the individual verifiers.

Rationale for Section 95979(a).

This provision is necessary because conflict of interest must apply at the company and individual level to ensure a truly unbiased review of any Offset Project Data Report.

Summary of Section 95979(b)(1).

Subsection (b)(1) specifies that a high conflict of interest exists where the operator and verification body share specified staff within the previous three years.

Rationale for Section 95979(b)(1).

This provision is necessary because in order to provide an impartial and independent verification statement, it is necessary to avoid any relationships between parties that may be perceived as a conflict. If specified staff is shared between these parties, it would be perceived as a conflict of interest and would jeopardize the integrity of the program. Only verification bodies that are truly independent and can provide an objective opinion on the report may provide Offset Verification Services.

Summary of Section 95979(b)(2)(A) through (b)(2)(T).

Subsections (b)(2)(A) through (b)(2)(T) specify that a high conflict exists where the verification body staff has provided any of the listed non-verification services, including developing a GHG inventory, providing appraisal services, and providing any legal services.

Rationale for Section 95979(b)(2)(A) through (b)(2)(T).

These provisions are needed because in order for the verification body to remain independent and objective when providing Offset Verification Services, it is necessary to specify some services that are not allowed to have been provided during the past three years to the Offset Project Operator. These services are so

closely related to the type of work done during GHG verification that they must be considered a high risk for a conflict and potential for bias in review. Any staff that has provided any listed service means the verification body is not eligible to provide Offset Verification Services under this regulation until three years have passed from the date of those previous services.

Summary of Section 95979(b)(3).

Subsection (b)(3) specifies that any incentive provided to the Offset Project Operator by the verification body in order to provide verification services is a high conflict.Rationale for Section 95979(b)(3).

This provision is necessary because providing an incentive to the verifier would bias the verifier in the Offset Project Operator's favor.

Summary of Section 95979(b)(4).

Subsection (b)(4) states that any Offset Verification Services provided in the past three years to the Offset Project Operator, except for Offset Verification Services, as allowed for six years, is a high conflict of interest.

Rationale for Section 95979(b)(4).

Subsection (b)(4) is necessary to prevent complacency or bias in review. This section limits verifiers who have done these Offset Verification Services in the last three years from providing Offset Verification Services unless those services were provided as part of the allowed six years.

Summary of Section 95979(c).

Subsection (c) specifies that conflict of interest is low where no business relationship exists, or the services provided in the past three years were valued less than 20 percent of the fee for the proposed verification.

Rationale for Section 95979(c).

This provision is necessary because ARB has determined that some existing business relationships are acceptable if the dollar amount is small relative to the fee expected to be paid for verification. If the fee for verification is low relative to the consulting services, there may be an incentive to provide a positive or qualified positive offset verification statement in order to continue to be paid for other non-verification services. Having a dollar threshold allows the Offset Project Operator and verification body to determine if an existing business relationship is acceptable for future verification work.

Summary of Section 95979(d).

Subsection (d) specifies that a conflict is medium if the conflict is not high or low. The verification body would need to submit a mitigation plan to remove any conflicts, if possible, or if there are any personal or familiar relationships between the verification body and Offset Project Operator.

Rationale for Section 95979(d).

This provision is needed because ARB understands that some relationships may have existed between a verification body and an Offset Project Operator. If that relationship does not include any of the situations that constitute a high conflict of interest, then the verification body is afforded an opportunity to mitigate any other conflicts.

Summary of Section 95979(e).

Subsection (e) specifies requirements for submittal of information about potential conflicts of interest between the verification body and the Offset Project Operator. This information includes whether the conflict is high, medium, or low; whether any member of the verification team has provided any services to the Offset Project Operator in the past three years; and an attestation that the submitted information is accurate and complete.

Rationale for Section 95979(e).

This provision is necessary because the conflict-of-interest submittal allows the verification body to demonstrate that it has evaluated that potential for conflict of interest according to the regulation and certifies to the nature of any existing relationship under penalty of perjury.

Summary of Section 95979(f)(1).

Subsection (f)(1) requires the verification body to monitor and disclose conflicts of interest after commencement of verification services for an Offset Project Operator. The disclosure must also present details about the conflict of interest and how the verification body will mitigate or neutralize the potential for conflict of interest.

Rationale for Section 95979(f)(1).

This provision is necessary so that a verification body is diligent and careful not to engage in any activities beyond GHG verification that could be perceived as a potential conflict of interest. This is important to the integrity of the program.

Summary of Section 95979(f)(2).

Subsection (f)(2) requires the verification body to monitor for conflicts of interest for up to one year after the completion of verification services. The verification body must disclose to ARB within 30 days once it enters into another contract for

non-verification services with the Offset Project Operator. ARB or an OPR will make a decision as to whether the conflict of interest is high and jeopardizes the Offset Verification Statement and the accreditation of the verification body.

Rationale for Section 95979(f)(2).

This provision is necessary to maintain the integrity of the program and ensure there is no bias by the verification body by the promise of future work for the Offset Project Operator.

Summary of Section 95979(f)(3).

Subsection (f)(3) requires the verification body to disclose any emerging conflicts of interest that may become apparent during the course of verification services. If the conflict is determined to be high, the verification body will not be allowed to continue providing the verification services.

Rationale for Section 95979(f)(3).

This section is necessary to maintain the integrity of the program and ensure that even during the course of verification services, the verification body does not do anything that would be perceived as a conflict of interest under the regulation.

Summary of Section 95979(f)(4).

Subsection (f)(4) requires the verification body to notify ARB of any changes to their business structure within one year of providing Offset Verification Services.

Rationale for Section 95979(f)(4).

This provision is necessary because ARB must ensure that a financial arrangement or promise of financial arrangement is not made between the verification body and the Offset Project Operator in order to win a positive offset verification statement. ARB must be notified if any changes to the verification body, such as mergers or acquisitions, are made; especially any that involve the Offset Project Operator.

Summary of Section 95979(f)(5).

Subsection (f)(5) allows ARB to rescind an Offset Verification Statement and provides 90 days for an Offset Project Operator to hire another verification body if the first verification body violates the conflict-of-interest requirements.

Rationale for Section 95979(f)(5).

This provision is necessary because if a verification body violates the conflict-of-interest requirements, it is necessary to provide the Offset Project Operator with additional time in which to hire another verification body. A violation of the

conflict of interest means the Offset Verification Statement may not have been objective and a new Offset Verification Statement must be submitted by a different verification body.

Summary of Section 95979(f)(6).

Subsection (f)(6) allows ARB to rescind the accreditation of the verification body or verifiers if they violate the conflict-of-interest requirements.

Rationale for Section 95979(f)(6).

This provision is necessary because the penalty for violating the conflict-of-interest requirements must be specified so that all parties understand what the consequences of providing services to an Offset Project Operator are when a previous relationship with an Offset Project Operator is not disclosed to ARB. Rescinding the accreditation of a verification body means that company would no longer be allowed to verify data in ARB's cap-and-trade program.

Section 95980. Issuance of Offset Credits.

Summary of Section 95980(a).

Subsection (a) proposes the requirements that GHG emissions reductions or GHG removal enhancements must meet to be issued offsets. This section also proposes that an offset credit is equal to one metric ton of CO_2e and that the GHG emissions reductions or GHG removal enhancements must occur at the location where the reduction activity is implemented (direct).

Rationale for Section 95980(a).

This provision is necessary to ensure that all offset credits issued under ARB protocols meet the same requirements. An offset credit should be equal to one metric ton of CO_2e, so that it is equivalent to an allowance. Direct GHG emissions reductions or direct GHG removal enhancements are the simplest and most straightforward to incorporate into an offset project because they occur on-site and can therefore, be easily verified. Crediting direct reductions that occur on-site also makes ownership of offset credits that result from an offset project clearer, and the risk of double-counting is reduced.

Summary of Section 95980(a)(1).

Subsection (a)(1) proposes that an offset credit may only be issued to an offset project that has been listed with ARB or an OPR.

Rationale for Section 95980(a)(1).

This provision is necessary to ensure that ARB or an OPR has all the relevant information regarding an offset project, that information regarding the offset

project has been made publicly available, and that ARB has a legal and enforcement connection to those involved with offset projects.

Summary of Section 95980(a)(2).

Subsection (a)(2) proposes that offset credits may only be issued if the offset project was issued a positive offset or qualified positive offset verification statement by an ARB-accredited offset verifier.

Rationale for Section 95980(a)(2).

This provision is necessary to ensure that GHG emissions reductions or GHG removal enhancements are qualified by an ARB-accredited third-party verifier. Having an accredited verifier issue a positive offset or qualified positive offset verification statement ensures confidence in the verification by the public, ARB, and an OPR.

Summary of Section 95980(a)(3).

Subsection (a)(3) proposes that offset credits may only be issued if an ARB-accredited offset verifier has submitted a positive offset or qualified positive offset verification statement to ARB, or an OPR and has been attested to by an ARB-accredited offset verifier.

Rationale for Section 95980(a)(3).

ARB or an OPR must receive the positive offset or qualified positive offset verification statement and review it to determine if offset credits should be issued.

Summary of Section 95980(b), Determination for Timing and Duration of Initial Crediting Periods.

Subsection (b) proposes that an offset project's initial crediting period will begin on the date that its first offset verification statement says that GHG emission reductions or GHG removal enhancements actually occurred.

Rationale for Section 95980(b).

This provision is necessary to establish when the offset project's initial crediting period begins. This timing is appropriate because it sometimes takes a while for the offset project to be fully implemented and the crediting period should reflect the timeframe that the project reduces GHG emissions or stores GHGs.

Summary of Section 95980(c), Determination for Timing and Duration of Renewed Crediting Periods.

Subsection (c) proposes that an offset project's renewed crediting period will begin on the date following the conclusion of the offset project's initial crediting period or previously renewed crediting period.

Rationale for Section 95980(c).

This provision is necessary to establish when the offset project's renewed crediting period begins. This timing is appropriate because, unlike the initial crediting period, the project should already be implemented at the time it renews its crediting period.

Section 95981. Process for Issuance of Offset Credits.

Summary of Section 95981(a).

Subsection (a) proposes the timing for offset credits being issued by ARB or an OPR. Offset credits will be issued by ARB or an OPR within 45 days of receiving a positive offset or qualified positive offset verification statement.

Rationale for Section 95981(a).

This provision is necessary so the party identified to receive offset credits knows when they will receive them. 45 days will give staff enough time to review the offset verification statements and contact the offset verifier if there are any questions regarding the statement.

Summary of Section 9598(b), Change of Listing Status.

Subsection (b) proposes that once offset credits have been issued by ARB or an OPR to an offset project, the listing status of the offset project will be changed to either an "Active Project" or "Active Renewal."

Rationale for Section 95981(b).

This provision is necessary for transparency purposes, so the public knows whether or not an offset project has been issued offset credits. This information will be available on a public website, and the number of offset credits issued to the offset project for each offset verification statement will also be made available.

Summary of Section 95981(c), Notice of Determination of Issuance of Offset Credits.

Subsection (c) proposes that ARB or an OPR will notify the party identified to receive offset credits, within15 days of issuance, that the credits have been issued.

Rationale for Section 95981(c).

This provision is necessary so that the party identified to receive offset credits knows that ARB or an OPR has issued them. The 15-day timeframe is designed to allow staff to prepare the necessary notification and, if applicable, any documentation to send to the recipient of the offset credits.

Summary of Section 95981(d), Requirements for Offset Projects Submitted Through an Offset Project Registry Seeking Issuance of ARB Offset Credits.

Subsection (d) proposes requirements for offset projects whose documentation was submitted through an OPR, if the party responsible for the offset project is seeking offset credits issued by ARB.

Rationale for Section 95981(d).

This provision is necessary because an offset credit must ultimately be issued by ARB to be used for compliance under this article.

Summary of Section 95981(d)(1).

Subsection (d)(1) proposes the information that the party responsible for the offset project must submit to be issued offset credits by ARB.

Rationale for Section 95981(d)(1).

This provision is necessary because ARB must obtain all information submitted to an OPR for the offset project including: listing, monitoring, reporting, and verification information, to issue an offset credit. The attestations must also be made available to ARB so that it can enforce against those responsible for offset projects, if necessary.

Summary of Section 95981(d)(2).

Subsection (d)(2) proposes that the verification body that submitted offset verification statements to an OPR must attest to ARB the truthfulness and accuracy of its findings.

Rationale for Section 95981(d)(2).

This provision is necessary so that ARB can enforce against the verification bodies and verifiers that provided verification services to an offset project through an OPR.

Summary of Section 95981(d)(3).

Subsection (d)(3) proposes that ARB will notify the party responsible for the offset project within 30 days, whether the information they submitted is complete, and if not, what is deficient.

Rationale for Section 95981(d)(3).

This provision is necessary so that the party responsible for the offset project knows if the information they submitted is complete, and if not, what additional information they must submit. The 30-day timeframe is designed to allow staff adequate time to review the material submitted for issuance of ARB offsets.

Summary of Section 95981(d)(4).

Subsection (d)(4) proposes that ARB will issue offset credits within 30 days of determining that the information submitted for issuance of ARB offsets is complete.

Rationale for Section 95981(d)(4).

This provision is necessary so that the parties involved in the offset project know that ARB has issued offsets. The 30-day timeframe is designed to allow staff to prepare the necessary notification and, if applicable, any documentation to send to those involved in the offset project.

Summary of Section 95981(d)(5).

Subsection (d)(5) proposes that ARB may request additional information for issuance of ARB offsets, as needed, before issuing offset credits.

Rationale for Section 95981(d)(5).

This provision allows those responsible for the offset project, or those that verified the project, to provide any additional information that ARB deems necessary to the issuance of ARB offsets.

Summary of Section 95981(d)(6).

Subsection (d)(6) proposes that ARB may deny issuance of ARB offset credits. The party responsible for the offset project may petition to be allowed to resubmit its information and respond to any issues that prevented ARB from issuing offset credits.

Rationale for Section 95981(d)(6).

This provision is necessary to allow ARB to deny issuance of ARB offsets if the information submitted is insufficient to warrant issuance. It is also necessary to give the party responsible for an offset project one last opportunity to show it qualifies to be issued ARB offset credits.

Summary of Section 95981(e).

Subsection (e) proposes that any offset credits issued by an OPR must be retired in its registry system before ARB can register the offset credits in its tracking system.

Rationale for Section 95981(e).

This provision is necessary to avoid double-counting of offset credits in multiple systems, and to ensure that the same offset credits cannot be bought, sold, or retired if they have already been used.

Summary of Section 95981(f), Receipt of Offset Credits Issued by ARB.

Subsection (f) proposes that ARB offset credits will be registered to the party identified to receive offset credits within 15 days of notification.

Rationale for Section 95981(f).

This provision is necessary to ensure that the party identified to receive offset credits knows they have been deposited into their account. The 15-day timeframe is designed to allow ARB time to transfer the offset credits to the correct party and process the transactions in the tracking system correctly.

Section 95982. Registration of Offset Credits Issued by ARB.

Summary of Section 95982.

This section proposes that offset credits issued by ARB must be registered in ARB's tracking system.

Rationale for Section 95982.

This section is necessary for ARB to track offset credits it issues, as well as owners of offset credits at all times.

Summary of Section 95982(a).

Subsection (a) proposes that each offset credit be given a unique serial number.

Rationale for Section 95982(a).

This section is necessary so that each offset credit cannot be used more than once and ARB is able to track who owns each offset at all times.

Summary of Section 95982(b).

Subsection (b) proposes that ARB offset credits will be transferred to the account of the party identified to receive offset credits.

Rationale for Section 95982(b).

This provision is necessary to ensure that the party identified to receive offset credits knows they have been deposited into their account.

Section 95983. Offset Reversals.

Summary of Section 95983(a).

Subsection (a) proposes that a portion of offset credits issued to forestry projects developed under the U.S. Forest Projects Protocol must be placed into the Forest Buffer Account. If the offset project originated with an OPR, these offset credits must be transferred to ARB.

Rationale for Section 95983(a).

This provision is necessary to develop an ARB insurance mechanism that can be used to protect against unintentional reversals that may occur in forest projects.

Summary of Section 95983(a)(1).

Subsection (a)(1) proposes that the amount of offset credits that must be placed into the Forest Buffer Account is specified in the U.S. Forest Projects Protocol, incorporated by reference.

Rationale for Section 95983(a)(1).

This provision is necessary to determine how many offset credits must be placed into the Forest Buffer Account. This amount is based on a number of default and calculated factors that differ depending on the individual project. The factors and equations that must be used to determine each project's reversal risk rating are provided in the U.S. Forest Projects Protocol.

Summary of Section 95983(a)(2).

Subsection (a)(2) proposes that offset credits be placed into the Forest Buffer Account at the time offset credits are registered.

Rationale for Section 95983(a)(2).

This provision is necessary to ensure offset credits are immediately placed into the Forest Buffer Account, as opposed to the account of the party identified to receive offset credits.

Summary of Section 95983(a)(3).

Subsection (a)(3) proposes that all offset credits initially held by an OPR for unintentional reversals be transferred to ARB's Forest Buffer Account, and then retired in its own registry system.

Rationale for Section 95983(a)(3).

This provision is necessary to ensure that the size of the Forest Buffer Account is adequate enough to cover a large loss of stored carbon in the forest sector. If each OPR maintains its own buffer account and does not transfer the offset credits to ARB there may not be enough offset credits in the Forest Buffer Account if a large loss occurs.

Summary of Section 95983(b), Unintentional Reversals.

Subsection (b) proposes that the party responsible for an offset project must notify ARB within six months when an unintentional reversal is discovered.

Rationale for Section 95983(b).

This provision is necessary so that ARB is informed that an unintentional reversal occurred.

Summary of Section 95983(b)(1).

Subsection (b)(1) proposes the information that a party responsible for a forest offset project must submit to ARB in the event of an unintentional reversal.

Rationale for Section 95983(b)(1).

This provision is necessary so that ARB can assess why a reversal occurred, whether it was unintentional, and how many metric tons of GHGs were reversed.

Summary of Section 95983(b)(1)(A).

Subsection (b)(1)(A) proposes that a party responsible for a forest offset project must explain to ARB the nature of the unintentional reversal.

Rationale for Section 95983(b)(1)(A).

This provision is necessary so that ARB can assess why a reversal occurred to determine if it was unintentional.

Summary of Section 95983(b)(1)(B).

Subsection (b)(1)(B) proposes that a party responsible for a forest offset project must verify the level of carbon stored in its forest within a year of when the unintentional reversal was discovered.

Rationale for Section 95983(b)(1)(B).

This provision is necessary so that ARB can determine how many metric tons of GHGs were reversed.

Summary of Section 95983(b)(2).

Subsection (b)(2) proposes that ARB will retire offset credits from the Forest Buffer Account in the amount of the reversal.

Rationale for Section 95983(b)(2).

This provision is necessary to ensure the permanence of offset credits issued for stored carbon. If credited GHGs have been released back into the atmosphere, an equivalent amount of offset credits must be retired to replace it. If it is not replaced by another offset or an allowance, there is a net increase of GHGs in the atmosphere.

Summary of Section 95983(c), Intentional Reversals.

Subsection (c) proposes the requirements for the parties responsible for the forest offset projects in the event of an intentional reversal.

Rationale for Section 95983(c).

This provision is necessary to establish the requirements for intentional reversals.

Summary of Section 95983(c)(1).

Subsection (c)(1) proposes that within 30 days of an intentional reversal, the party responsible for the project must give written notice to ARB of the occurrence. They must also explain and describe the nature of the intentional reversal.

Rationale for Section 95983(c)(1).

This provision is necessary for ARB to be notified that an intentional reversal occurred and evaluate the nature of the intentional reversal.

Summary of Section 95983(c)(2).

Subsection (c)(2) proposes that ARB will evaluate the information submitted to determine if an intentional reversal has occurred. If ARB determines that an intentional reversal has occurred, it will notify the party responsible for the offset project of its findings.

Rationale for Section 95983(c)(2).

This provision is necessary so that the party responsible for the offset project is informed of ARB's determination that it believes an intentional reversal has occurred.

Summary of Section 95983(c)(3).

Subsection (c)(3) proposes that three months within receiving ARB's notification pursuant to section 95983(c)(2), the party responsible for a forest offset project must verify the level of carbon stored in its forest.

Rationale for Section 95983(c)(3).

This provision is necessary so that ARB can determine how many metric tons of GHGs were reversed, and if necessary, take enforcement action.

Summary of Section 95983(d), Disposition of Forest Sequestration Projects After an Unintentional Reversal.

Subsection (d) proposes that if an unintentional reversal occurs, and its stored carbon levels are below its project baseline, the project will be automatically terminated.

Rationale for Section 95983(d).

This provision is necessary because the project baseline is no longer applicable and can no longer be used to determine project performance.

Summary of Section 95983(d)(1).

Subsection (d)(1) proposes that if an offset project has been terminated due to an unintentional reversal, the party responsible for the offset project may resubmit the offset project for listing.

Rationale for Section 95983(d)(1).

This provision is necessary to allow projects that suffer unintentional reversals the ability to submit a new project with a new revised baseline calculation.

Summary of Section 95983(d)(2).

Subsection (d)(2) proposes that if an unintentional reversal occurs, and its stored carbon levels are above its project baseline, it may continue to operate as long as the number of released GHGs have been replaced with an equivalent amount of offset credits from the Forest Buffer Account. This subsection also proposes that the party responsible for the forest project must continue to contribute to the Forest Buffer Account in the future.

Rationale for Section 95983(d)(2).

This provision is necessary to allow a forest project that undergoes an unintentional reversal to continue generating offset credits utilizing the same baseline.

Summary of Section 95983(e), Disposition of Forest Sequestration Projects After an Intentional Reversal.

Subsection (e) proposes what should happen to a forest offset project in the event on an intentional reversal.

Rationale for Section 95983(e).

This provision is necessary so that the party responsible for a forest offset project knows what will happen if there is an intentional reversal of a forest project.

Summary of Section 95983(e)(1).

Subsection (e)(1) proposes that if ARB determines an intentional reversal has occurred, the forest offset project will be automatically terminated.

Rationale for Section 95983(e)(1).

This provision is necessary to ensure the additionality of credited reductions. This provision prevents projects from intentionally reversing credited carbon stocks below allowable levels, and registering a new project that would yield credits from the intentionally reduced stocks.

Summary of Section 95983(e)(2).

Subsection (e)(2) proposes that if an intentional reversal has occurred, a new forest offset project may not be initiated within the same project boundary.

Rationale for Section 95983(e)(2).

This provision is necessary to ensure that, in the case of an intentional reversal, an amount of offset credits equivalent to the reversed carbon previously issued to the project is invalidated and replaced.

Summary of Section 95983(e)(3).

Subsection (e)(3) proposes that offset credits issued to a terminated forest offset project due to an intentional reversal may be invalidated pursuant to section 95985.

Rationale for Section 95983(e)(3).

This provision is necessary because the stored carbon is no longer considered permanent in the event of a reversal. Offset projects may not draw from the Forest Buffer Account to replace offset credits for intentionally reversed forest projects. Pursuant to section 95985(e), in the event of an intentional reversal, the party responsible for the forest offset project must replace any lost metric tons with other approved offset credits or allowances.

Section 95984. Ownership and Transferability of Offset Credits Issued by ARB.

Summary of Section 95984.

Section 95984 proposes that initial ownership of offset credits will be with the party identified to receive offset credits. It also purposes that offset credits may be sold, traded, or transferred except in limited circumstances, as identified in this section.

Rationale for Section 95984.

This provision is necessary for those responsible for offset projects to know who receives ownership of offset credits and which transactions are allowed.

Summary of Section 95984(a).

Subsection (a) proposes that an offset credit that has been retired or surrendered in any program may not be sold, traded, or transferred.

Rationale for Section 95984(a).

This provision is necessary to avoid double-counting of offset credits.

Summary of Section 95984(b).

Subsection (b) proposes that offset credits in the forest buffer may not be sold, traded, or transferred.

Rationale for Section 95984(b).

This provision is necessary because offset credits in the Forest Buffer Account may only be retired by ARB in the event of an unintentional reversal.

Summary of Section 95984(c).

Subsection (c) proposes that an offset credit that has been invalidated pursuant to section 95985 may not be sold, traded, or transferred.

Rationale for Section 95984(c).

This provision is necessary because once an offset credit is invalidated, ARB will cancel the offset credit in the tracking system, and it may no longer be sold, traded, or transferred.

Section 95985. Invalidation of Offset Credits.

Summary of Section 95985(a).

Subsection (a) proposes the circumstances for offset credits to be considered valid.

Rationale for Section 95985(a).

This provision is necessary so that those developing offset projects or those purchasing offset credits know which offset credits are valid.

Summary of Section 95985(a)(1).

Subsection (a)(1) proposes that offset credits are considered valid and can be used for compliance unless they have been retired or used in any voluntary or regulatory program.

Rationale for Section 95985(a)(1).

This provision is necessary to avoid double-counting of offset credits in multiple systems, and to ensure that the same offset credits cannot be bought, sold, or retired if they have already been used.

Summary of Section 95985(a)(2).

Subsection (a)(2) proposes that offset credits are considered valid and can be used for compliance unless they have been invalidated under this section.

Rationale for Section 95985(a)(2).

This provision is necessary because once an offset credit is invalidated, ARB will cancel the offset credit in the tracking system, and it may no longer be sold, traded, or transferred.

Summary of Section 95985(b).

Subsection (b) proposes the circumstances for an offset credit to be invalidated.

Rationale for Section 95985(b).

This provision is necessary so those developing offset projects or those purchasing offset credits know which offset credits are valid. In the event of fraud or malfeasance on the part of project developers or verifiers, there may be cause to invalidate offset credits after they have been issued, to protect the environmental integrity of the program.

Summary of Section 95985(b)(1).

Subsection (b)(1) proposes that an offset credit may be invalidated if a reversal occurred in a forest sequestration project.

Rationale for Section 95985(b)(1).

This provision is necessary because if a reversal occurs in a forest project, the offset credits are no longer permanent and, therefore, no longer meet the requirements of AB 32.

Summary of Section 95985(b)(2).

Subsection (b)(2) proposes that an offset credit may be invalidated if a deficiency or errors were found on behalf of the project developers or verifiers for an offset project.

Rationale for Section 95985(b)(2).

This provision is necessary so those developing offset projects or those purchasing offset credits know which offset credits are valid. In the event of fraud or malfeasance of project developers or verifiers, there may be cause to invalidate offset credits after they have been issued, to protect the environmental integrity of the program.

Summary of Section 95985(c).

Subsection (c) proposes what will happen if an offset is determined to be invalid.

Rationale for Section 95985(c).

This provision is necessary so those that have used or are currently holding an invalid offset credit know the procedures for completing the invalidation process.

Summary of Section 95985(c)(1).

Subsection (c)(1) proposes that an invalid offset will be cancelled or removed from any Compliance or Holding Accounts, as well as the Forest Buffer Account.

Rationale for Section 95985(c)(1).

This provision is necessary so those that are currently holding or attempting to comply with an invalid offset credit know the procedures for completing the invalidation process.

Summary of Section 95985(c)(2).

Subsection (c)(2) proposes that the current holder or the entity that retired the offset credit will be notified.

Rationale for Section 95985(c)(2).

This provision is necessary so that participants know if an offset they currently hold or have used is invalidated.

Summary of Section 95985(c)(3).

Subsection (c)(3) proposes that ARB will notify any linked program if any offset credits are invalidated.

Rationale for Section 95985(c)(3).

This provision is necessary so that the linked program can remove the offset credits from within their own tracking system, and they do not allow it to be used for compliance in their programs.

Summary of Section 95985(d).

Subsection (d) proposes that if an offset credit is invalidated after it has been used or retired, for any reason except a reversal in the forest sector; the party that retired or used the offset credit must replace it to ARB within 30 days. If the user or retiree is no longer in business, ARB will notify the developer of the offset project that they must replace the offset credits within 30 days. If they do not replace it within that time frame, each offset credit constitutes a violation.

Rationale for Section 95985(d).

This provision is necessary to ensure that purchasers and users of offset credits do their due diligence in seeking out high-quality offset credits. Also, ARB has clear enforcement authority over covered entities that will be using ARB offsets for compliance.

Summary of Section 95985(e).

Subsection (e) proposes that if an offset credit is invalidated due to an intentional reversal in the forest sector, the party responsible for the offset project must replace the offset credits that are reversed.

Rationale for Section 95985(e).

This provision is necessary because those with an interest in the land must ensure permanence. If the forest owner is not the one to replace the offset credits in this case, they have no incentive to uphold their obligations to ensure permanence.

Summary of Section 95985(f).

Subsection (f) proposes that if an offset credit is invalidated due to an unintentional reversal the offset credits will be retired from the Forest Buffer Account.

Rationale for Section 95985(f).

This provision is necessary because ARB's Forest Buffer Account is intended to act as an insurance mechanism that can be used to protect against unintentional reversals that may occur in forest projects.

Section 95986. Executive Officer Approval Requirements for Offset Project Registries.

Summary of Section 95986.

This section provides requirements that must be met and demonstrated by an Offset Project Registry that wishes to be approved by the Executive Officer to provide registry services for projects developed using ARB compliance offset protocols.

Rationale for Section 95986.

This section is necessary to have some basic requirements for all registries that wish to be approved as an Offset Project Registry, to ensure quality and stability in this role.

Summary of Sections 95986(a) through (c).

Subsections (a) through (c) require an Offset Project Registry to provide information about its organization, demonstration of $50 million of liability insurance, and demonstration of a rigorous internal conflict-of-interest policy and mechanisms to disclose and prevent conflicts of interest.

Rationale for Sections 95986(a) through (c).

These provisions are necessary because beyond the basic information about the management of the Offset Project Registry, it is important for the registry to carry insurance to provide a way to compensate operators if, for some reason, the registry fails to provide quality or accurate registry services and the result is a loss of potential compliance credits for the operator. This level of insurance is based on expected volumes of potential compliance offsets and potential monetary value of those offsets the registry may reasonably oversee. It is important that all members of an approved Offset Project Registry remain impartial as they provide services to operators when those services potentially will generate offsets that count in a compliance program.

Summary of Section 95986(d).

Subsection (d) limits any other roles an Offset Project Registry can fill while it is providing registry services.

Rationale for Section 95986(d).

This provision is necessary because as an Offset Project Registry, the organization must take a step back from any other roles that could lead to a perceived or actual conflict of interest in the process of generating potential compliance offsets. This provision will add integrity to the program and remove the threat of self-interest in the process by the registry.

Summary of Sections 95986(e) through (f).

Subsections (e) through (f) ensure that the requirements that must be demonstrated at the time of approval are always met during any time the approved Offset Project Registry is providing registry services under the regulation.

Rationale for Sections 95986(e) through (f).

These provisions are necessary for the stability of the program. It is imperative that once an Offset Project Registry demonstrates that it meets the regulation's standards, it maintains those standards from that point forward while providing registry services.

Summary for Section 95986(g).

Subsection (g) requires attestations statements to hold the Offset Project Registry accountable to ARB for information that it submits to ARB and acknowledgement that the registry is voluntarily choosing to become part of a regulatory program, and as such is subject to all enforcement mechanisms of the program and that any information provided to ARB will be accurate and complete.

Rationale for Section 95986(g).

This provision is necessary because all parties that are part of the compliance program must be held accountable for their actions, registry services, and information submittals for the integrity of the program.

Summary for Section 95986(h).

Subsection (h) requires management staff for an OPR to take ARB training on the ARB program.

Rationale for Section 95986(h).

This provision is necessary because it is important to the integrity of the compliance program that any approved registry understand the requirements of the regulatory program and be able to communicate those requirements to operators that use their registry services.

Summary of Section 95986(i).

Subsection (i) lays out the process for actual approval for an Offset Project Registry once all of the requirements have been met. The approval is valid for five years and may be renewed if the registry has not been subject to enforcement and still meets all of the requirements.

Rationale for Section 95986(i).

This provision is necessary to limit the approval to five years, which allows ARB to periodically ensure that all requirements for registry approval are met and ensure the quality of registries by not allowing any registries that have been subject to enforcement to be eligible to be renewed for approval by ARB.

Summary of Section 95986(j).

Subsection (j) provides a process for modifying, suspending, or revoking the approval of an Offset Project Registry for good cause. It also stipulates that the OPR must not provide registry services during an approval revocation and must notify all operators of its status.

Rationale for Section 95986(j).

This provision is necessary so that the registry is afforded due process under California statute before ARB revokes its approval. Operators must be given notice by the registry if it can no longer provide registry services, so they may transfer to another registry or to ARB.

Section 95987. Offset Project Registry Requirements.

Summary of Section 95987.

This section provides the registry services an approved Offset Project Registry must provide for operators and information it must provide to ARB under the regulation.

Rationale for Section 95987.

The regulation provides standardized services so that every registry will provide the same level of service and information related to the generation of potential

offset credits. The information requirements will be used by ARB as oversight of its compliance offset program and approved OPRs.

Summary of Section 95987(a).

Subsection (a) stipulates that only ARB Board-approved protocols can be used to generate offsets for potential ARB issuance.

Rationale for Section 95987(a).

This provision is necessary because AB 32 is clear that the Board must approve all offset protocols.

Summary for Section 95987(b).

Subsection (b) stipulates what information related to project listing and reporting the registry has to make available to the public in a timely manner.

Rationale of Section 95987(b).

This provision ensures that all registries provide information in a transparent manner for each offset project with the potential for ARB to issue credits.

Summary of Section 95987(c).

Subsection (c) requires the OPR to use the conflict-of-interest requirements in the regulation to make a determination about the level of conflict between a verification body and the Offset Project Operator. This section also requires the OPR to ensure the information on the conflict-of-interest form is complete.

Rationale for Section 95987(c).

This provision is necessary to ensure that all OPRs apply the regulatory conflict-of-interest requirements and review each form for completeness. This ensures program integrity and consistency.

Summary of Section 95987(d).

Subsection (d) allows an OPR to provide guidance on questions or issues related to compliance offset protocols if there is no clear direction on that issue. The registry must inform ARB of any guidance it provides on a Compliance Offset Protocol.

Rationale for Section 95987(d).

This provision is necessary because there may be a circumstance where an operator or verifier may not know how to apply the requirements of a Compliance Offset Protocol, and this allows the OPR to provide such guidance and inform ARB in a timely manner. ARB can track such inquiries and decide if such issues

need to be addressed in an update to the protocol, of it the registry has provided guidance that is in conflict of the regulatory offset program and the operator should be notified quickly to avoid losing any potential offset credits.

Summary of Section 95987(e).

Subsection (e) requires approved registries to have in place an audit program of their projects and verifications that includes specific tasks that must be conducted in the audits, and they must provide that information to ARB.

Rationale for Section 95987(e).

This provision is necessary because it is important for all registries to have some oversight of their own program as they provide registry services, to ensure integrity and quality at each step. This information will also be provided to ARB to inform ARB staff, to support their efforts to oversee the regulatory verification program.

Summary of Section 95987(f).

Subsection (f) requires that an OPR provide all information related to an offset project, if requested by ARB.

Rationale for Section 95987(f).

This provision is necessary because ARB may need such information to audit a project or as part of its registry audit, conducted as part of its compliance offset program oversight.

Summary of Section 95987(g).

Subsection (g) requires an OPR to make all of its information and staff available to ARB for audit.

Rationale for Section 95987(g).

This provision is necessary because the OPRs are participating in a compliance program. ARB must have complete authority to oversee all facets of the program, including the OPRs. This access enables ARB to gather information or talk to staff as part of the OPR oversight.

Summary of Section 95987(h).

Subsection (h) requires the OPR to retire any credits in its system that will be issued offset credit in ARB's compliance offset program.

Rationale for Section 95987(h).

This provision is necessary because an offset credit may only be used once. This requirement ensures that someone is not able to have an offset credit double-counted in any program once ARB decides to issue an offset credit for use in its regulatory program.

Summary of Section 95987(i).

Subsection (i) requires an OPR to provide annual information to ARB related to any offset projects that are at least listed for the previous year using a Compliance Offset Protocol.

Rationale for Section 95987(i).

This provision is necessary so that ARB can monitor the performance of its offset program. It also allows ARB to understand and respond to any unintended or unexpected issues that may occur during the implementation of the compliance offset program.

Section 95988. Record Retention Requirements for Offset Project Registries.

Summary of Section 95988.

This section requires registries to retain specific documentation for at least the project lifetime plus ten years for projects that are listed at an OPR and eventually receive ARB-issued credit.

Rationale for Section 95988.

This provision is necessary because as with all participants in the cap-and-trade program, the registry must maintain a rigorous record retention program to support any regulatory inquiries about a project or verification that was conducted through the registry.

Subarticle 14. Recognition of Compliance Instruments from Other Programs.

Section 95990. Recognition of Offset Credits for Early Action.

Summary of Section 95990(a).

Subsection (a) proposes that ARB recognizes early action offset credits issued by third-party programs approved pursuant to this section, if the offset credits meet the requirements of this section.

Rationale for Section 95990(a).

This section is necessary to establish that early action offset credits must meet specific criteria. This ensures that early action offset credits are subjected to uniform standards.

Summary of Section 95990(b), Criteria for Approval of Offset Credits Issued by Third Parties.

Subsection (b) proposes the criteria that offsets issued by third-party programs must meet to be recognized for compliance.

Rationale for Section 95990(b).

This section is necessary to ensure that all early action offset credits issued by third-party programs meet the same standards.

Summary of Section 95990(b)(1).

Subsection (b)(1) proposes that the GHG reductions or GHG removal enhancements credited as offsets by third-party programs must occur between January 1, 2005, and December 31, 2014.

Rationale for Section 95990(b)(1).

This provision is necessary so those using offsets for compliance know which early action offset credits are eligible to be used for compliance. The date January 1, 2005, reflects the date that offset projects began verifying their GHG reductions and GHG removal enhancements, based on the protocols approved in this section for recognizing early action. The date December 31, 2014, reflects the date that the first compliance period ends. Staff proposes this cut-off date to ensure that offset projects switch to a Board-approved protocol, while still allowing a supply of offset credits to come in during the first compliance period.

Summary of Section 95990(b)(2).

Subsection (b)(2) proposes that offsets issued by third-party programs must be verified according to the requirements in section 95990(f).

Rationale for Section 95990(b)(2).

This provision is necessary to ensure that early action offset credits issued by third-party programs meet the same requirements for verification as offset credits issued by ARB.

Summary of Section 95990(b)(3).

Subsection (b)(3) proposes that qualified early action offset credits must originate from offset projects that commence prior to January 1, 2012.

Rationale for Section 95990(b)(3).

This provision is necessary so those using offsets for compliance know which early action offset credits are eligible to be used for compliance. This also ensures that once ARB's compliance offset program is implemented in 2012, that offset projects are using ARB Board-approved protocols, as opposed to those approved in this section for early action purposes.

Summary of Section 95990(b)(4).

Subsection (b)(4) proposes that qualified early action offset credits must originate from offset projects that are located in the United States.

Rationale for Section 95990(b)(4).

This provision is necessary so those using offsets for compliance know which early action offset credits are eligible to be used for compliance. Up to this point, staff has only evaluated protocols based on applicability in the United States.

Summary of Section 95990(b)(5)(A) through (b)(5)(D).

Subsections (b)(5)(A) through (b)(5)(D) propose which offset protocols are eligible to be used for the recognition of early action offset credits.

Rationale for Section 95990(b)(5)(A) through (b)(5)(D).

These provisions are necessary so that those using offsets for compliance know which early action offset credits are eligible to be used for compliance. Staff chooses these particular protocols because they are the same types of offset projects that staff is proposing that the Board adopt as ARB compliance offset protocols. Staff has knowledge of these project types and has also based the development of its proposed compliance protocols on these early versions.

Summary of Section 95990(b)(5)(E).

Subsection (b)(5)(E) proposes that offset projects using Climate Action Reserve Forestry Protocol versions 3.0 through 3.2 meet specific requirements for permanence, including: a conservation easement or contribution to a forest buffer pool.

Rationale for Section 95990(b)(5)(E).

This provision is necessary to ensure that early action offset credits meet the same requirements for permanence as offset credits issued by ARB.

Summary of Section 95990(c), Approval of Third-Party Offset Programs for Purposes of Accepting Offset Credits for Early Action.

Subsection (c) proposes the requirements that a third-party offset program must meet for offset credits it issues to be used for early action.

Rationale for Section 95990(c).

This provision is necessary to ensure that all third-party offset programs meet the same requirements for offset credits as those that they issue to be used for early action. The third-party offset program must meet the requirements of this section or have an Executive Order issued pursuant to section 95986(d).

Summary of Section 95990(c)(1).

Subsection (c)(1) proposes that a third-party offset program must carry at least two million dollars of liability insurance.

Rationale for Section 95990(c)(1).

This provision is necessary to ensure that the third-party offset program has insurance to provide a way for compensation to project developers if, for some reason, the third-party program fails to provide quality or accurate services and the result is a loss of potential compliance credits for the project developer. The amount of insurance differs for these program in comparison to those for OPRs because the volume of early action offset credits is significantly lower than that which can be issued by an OPR under a Compliance Offset Protocol.

Summary of Section 95990(c)(2).

Subsection (c)(2) proposes that the third-party offset program has specific registration and tracking abilities for offset credits, as well as entities who are registered in its system.

Rationale for Section 95990(c)(2).

This provision is necessary to ensure that the third-party offset program can locate an offset credit or its owner at any given time within its registry system.

Summary of Section 95990(c)(3).

Subsection (c)(3) proposes that the third-party offset program's primary business be operating a voluntary or regulatory offset program.

Rationale for Section 95990(c)(3).

This provision is necessary to prevent conflict of interest.

Summary of Section 95990(c)(4).

Subsection (c)(4) proposes that the third-party offset program must submit to ARB any documentation that an offset project using a protocol approved for early action submits to the third-party program.

Rationale for Section 95990(c)(4).

This provision is necessary so that ARB has all information regarding offset projects from which offset credits are used for compliance under the program.

Summary of Section 95990(c)(5).

Subsection (c)(5) proposes that the third-party offset program must retire offset credits in its registry system before ARB can register the offset credits in its tracking system and allow them to be used for compliance.

Rationale for Section 95990(c)(5).

This provision is necessary to avoid double-counting of offset credits in multiple systems, and to ensure that the same offset credits cannot be bought, sold, or retired if they have already been used.

Summary of Section 95990(c)(6).

Subsection (c)(6) proposes that a representative of the third-party offset program must attest to ARB that they meet the requirements of this section, and that everything they submit is truthful and accurate.

Rationale for Section 95990(c)(6).

This provision is necessary to ensure that the third-party offset program follows the requirements of this regulation and that ARB can take enforcement against them if necessary.

Summary of Section 95990(d), Registration of Offset Credits Issued by Third Parties.

Subsection (d) proposes that any offset credits issued by a third-party offset program must be retired in its registry system before ARB can register the offset credits in its tracking system.

Rationale for Section 95990(d).

This provision is necessary to avoid double-counting of offset credits in multiple systems, and to ensure that the same offset credits cannot be bought, sold, or retired if they have already been used.

Summary of Section 95990(e), Ineligible Offset Credits Issued by Third Parties

Subsection (e) proposes that if an offset credit issued by a third-party offset program has been cancelled, used or, retired, it is no longer eligible to be recognized by ARB.

Rationale for Section 95990(e).

An offset credit may only be used once. This requirement ensures that someone is not able to have an offset credit double-counted in any program once ARB decides to recognize an offset credit for use in its regulatory program.

Summary of Section 95990(f), Regulatory Verification of Offset Credits for Early Action.

Subsection (f) proposes that all offset credits recognized from a third-party offset program must be verified according to requirements in this subsection.

Rationale for Section 95990(f).

AB 32 requires all offset credits used for compliance purposes to be subject to regulatory verification.

Summary of Section 95990(f)(1).

Subsection (f)(1) proposes that an offset credit must be verified by an ARB-accredited third-party verifier.

Rationale for Section 95990(f)(1).

All verifiers and verification bodies providing Offset Verification Services under the compliance offset program will be held to the same rigorous standards for accreditation. These standards are based on existing accreditation requirements in other voluntary and regulatory GHG reporting and offset programs. The requirements are also consistent with international best practices for verification body accreditation.

Summary of Section 95990(f)(2).

Subsection (f)(2) proposes that verification bodies be subject to conflict-of-interest standards, and that the conflict of interest be assessed against those

responsible for offset projects, if the offset credits from those programs are recognized by ARB.

Rationale for Section 95990(f)(2).

All verification bodies and verifiers are subject to regulatory conflict-of-interest requirements to ensure that there is an unbiased review of each Offset Project Data Report. This provision ensures that any verification bodies with previous relationships with any party with a financial interest in the offset credits are not allowed to verify those offset credits.

Summary of Section 95990(f)(3).

Subsection (f)(3) proposes that verification bodies must conduct all the verification services as specified in section 95977 for offset projects, if the offset credits from those program are recognized by ARB. The verification services are provided for the project as a whole, and not separately for each vintage year of credits.

Rationale for Section 95990(f)(3).

This provision is necessary so that all offset credits that can be used for compliance purposes meet the same requirements for verification. This provision helps to provide consistency among offset credits. The existing offset credits from a program recognized by ARB may be held by several parties who do not have access to the underlying data or other project information to support regulatory verification of the offset credits. This section applies the regulatory verification requirements across all vintage years for a project, so that any parties that hold existing credits may contract with a single verification body together, and the project information to support verification only has to be gathered once.

Section 95991. Sector-Based Offset Credits.

Summary of Section 95991.

This section establishes the requirements that offsets originating from developing countries or from subnational jurisdictions within those developing countries, with the exception of those identified in Article 13, must come through a sector-based crediting program that has been approved by the Board.

Rationale for Section 95991.

This provision is necessary because it defines the most basic terms for allowing international offset credits into California's cap-and-trade program and the specific developing countries generating offset credits.

Section 95992. Procedures for Approval of Sector-Based Crediting Programs.

Summary of Section 95992.

This section establishes that each sector-based crediting program must be approved by the Board after public notice and the opportunity for the public to submit comments in accordance with the Administrative Procedures Act, Government Code section 11340 et seq. The offset credits generated from these programs can be used to generate compliance offset credits accepted by ARB.

Rationale for Section 95992.

This provision ensures the integrity of the program by requiring that each program undergo a staff analysis and full public review prior to Board approval.

Section 95993. Sources for Sector-Based Offset Credits.

Summary of Section 95993(a).

Subsection (a) lists a specific type of sector-based offset credit for consideration in the California cap-and-trade program, known as Reducing Emissions from Deforestation and Forest Degradation (REDD).

Rationale for Section 95993(a).

This provision is necessary to propose that forest-sector offset credit programs be eligible for Board review and approval for recognition in the California cap-and-trade program.

Summary of Section 95993(b).

Subsection (b) is reserved for additional sources of sector-based credits for consideration in the California cap-and-trade program.

Rationale for Section 95993(b).

This subsection is reserved for additional sources of sector-based credits for consideration in the California cap-and-trade program, as other programs become available.

Section 95994. Requirements for Sector-Based Offset Crediting Programs.

Summary of Section 95994(a).

Subsection (a) establishes the general requirements that all sector-based offset crediting programs approved by the Board may be required to meet.

Rationale for Section 95994(a).

This provision is necessary to inform program developers of the minimum criteria that programs may be required to meet for Board consideration and approval; it is also necessary to ensure consistency by setting minimum standards by which each program will be assessed.

Summary of Section 95994(a)(1).

Subsection (a)(1) proposes that the sector-based offset crediting program include a plan for how the jurisdiction will reduce emissions from the sector in order to be considered for Board approval.

Rationale for Section 95994(a)(1).

This provision is necessary because it sets forth what could be incorporated in a jurisdiction's sector-level plan to inform ARB and the Board as to the jurisdiction's approach toward reducing emissions. This document will be used by staff to assess a proposed sector-based offset crediting program as part of Board approval.

Summary of Section 95994(a)(2).

Subsection (a)(2) establishes that a sector-based crediting program has a system in place for monitoring, inventory, reporting, and verification of GHG emissions for that sector, as well as enforcement capability over activities related to the program.

Rationale for Section 95994(a)(2).

This provision ensures integrity to the program because it requires activities to determine whether the credits meet the quality criteria under AB 32.

Summary of Section 95994(a)(3).

Subsection (a)(3) establishes the offset criteria that all sector-based offset credits issued by a sector-based program and approved by the Board be real, additional, quantifiable, permanent, verifiable, and enforceable, as required by AB 32.

Rationale for Section 95994(a)(3).

This provision is necessary because AB 32 requires that all offset credits be real, additional, quantifiable, permanent, verifiable, and enforceable, and covered entities and program developers of sector-based crediting programs need to know the basic requirements.

Summary of Section 95994(a)(4).

Subsection (a)(4) establishes that a Board-approved sector-based offset crediting program has a transparent system in place to evaluate the overall performance of the program.

Rationale for Section 95994(a)(4).

This provision is necessary so that ARB and those participating in the program know how the program is operating relative to the sector's reference level emissions, and whether the program is appropriately issuing offset credits based on reductions that occur after the program meets its crediting baseline.

Summary of Section 95994(a)(5).

Subsection (a)(5) proposes that a Board-approved sector-based offset crediting program has established public participation and participatory management mechanisms that provide for the participation and consultation of the public in the relevant jurisdiction during the program design process.

Rationale for Section 95994(a)(5).

As with programs designed and implemented by ARB directly, other programs, such as sector-based crediting programs, should allow for public involvement and consultation in the planning process in order to be eligible for ARB Board approval.

Summary of Section 95994(a)(6)(A).

Subsection (a)(6)(A) requires that for a sector-based crediting program to use a nested approach, emissions-reduction projects must follow a methodology to ensure the inventory, quantification, monitoring, verification, enforcement, and accounting for all project-level activities.

Rationale for Section 95994(a)(6)(A).

This provision is necessary because it provides guidance to jurisdictions and project developers pursuing a nested approach to sector-based crediting that individual projects follow an offset project methodology that is consistent with the requirements of AB 32.

Summary of Section 95994(a)(6)(B).

Subsection (a)(6)(B) establishes that when a sector-based crediting program uses a nested crediting pathway, emission reductions at the project level can be credited if the program has established a clear accounting system, whereby project-level emissions reductions can be properly accounted for and reconciled with emission reductions that occur at the jurisdictional level.

Rationale for Section 95994(a)(6)(B).

This provision is necessary because it ensures that all GHG sources and sinks are accounted for at both the project level and at the sectoral level, which substantially reduces the risk that credits are unintentionally counted twice and therefore violate AB 32's requirement that emission reductions from offsets must be real and additional.

Summary of Section 95994(b).

Subsection (b) establishes that pursuant to Section 95996, sector-based crediting programs may have requirements that are specific to that sector and in addition to the general requirements set out in Section 95994(a).

Rationale for Section 95994(b).

This provision is necessary because it reserves the ability of the Board to establish other requirements for sector-based crediting programs that are unique to the specific sector generating offset credits in a jurisdiction.

Section 95995. Quantitative Usage Limit.

Summary of Section 95995.

Section 95995 references section 95821(d), which identifies that sector-based credits recognized by the Board pursuant to 95991–95997 may be used by a covered entity to meet its compliance obligation. It also references section 95854, which further specifies that covered entities may submit sector-based credits of up to 25 percent, 25 percent, and 50 percent of their total offset quantitative limit during the first, second, and third compliance periods, respectively.

Rationale for Section 95995.

This section is necessary because it establishes which offset credits a covered entity may use from sector-based crediting programs and specifies to covered entities that a limited supply of international offset credits from Board-approved sector-based crediting programs may be used toward a compliance obligation

Section 95996. Reserved for Sector-Specific Requirements.

Summary of Section 95996.

Section 95996 is reserved for sector-specific requirements for specific sector-based crediting programs.

Rationale for Section 95996.

This section is reserved for sector-specific requirements for specific sector-based crediting programs.

Section 95997. Reserved for Approved Sector-Based Crediting Programs.

Summary of Section 95997.

Section 95997 is reserved for approved sector-based crediting programs.

Rationale for of Section 95997.

This section is reserved for approved sector-based crediting programs.

Subarticle 15. Enforcement and Penalties.

Section 96010. Jurisdiction.

Summary of Section 96010(a) through (d).

Subsections (a) through (d) contain a list of actions that will establish a person's consent to be subject to the jurisdiction of the State of California. These include registration with ARB; the purchase or holding of a compliance instrument issued by ARB; receipt of compensation of any kind from any transfer of compliance instruments issued by ARB; and verification of an offset credit to be issued by ARB.

Rationale for Section 96010(a) through (d).

These provisions are necessary because not all participants in the California cap-and-trade program will be located in California. ARB needs clear jurisdiction over all participants in order to enforce these regulations.

Section 96011. Authority to Suspend, Revoke, or Modify.

Summary of Section 96011(a).

Subsection (a) authorizes the Executive Officer to suspend, revoke, or place restrictions on the Holding Account of a voluntarily associated entity.

Rationale for Section 96011(a).

This provision is needed because in addition to conventional penalties, ARB may need to limit the ability of a registered entity to fully participate in the market as a response to violations by the entity. For voluntarily associated entities, ARB staff proposes that the Executive Officer be able to suspend, revoke, or place transaction restrictions on the Holding Accounts of violators.

Summary of Section 96011(b)

Subsection (b) authorizes the Executive Officer to place restrictions on the Holding Account of a covered entity or opt-in covered entity.

Rationale for Section 96011(b).

This provision is needed because the Executive Officer may need to supplement conventional penalties with restrictions on the accounts of entities that violate rules in order to prevent further violations.

Summary of Section 96011(c).

Subsection (c) authorizes the Executive Officer to suspend or revoke the registration of an entity registered pursuant to 95814(b) as an Other Registered participant.

Rationale for Section 96011(c).

This provision is needed to allow the Executive Officer to terminate the participation of some registered entities to prevent further violations.

Summary of Section 96011(d).

Subsection (d) authorizes the Executive Officer to suspend; revoke, or modify an existing Executive Order in response to violations by an entity.

Rationale for Section 96011(d).

This provision is necessary if the Executive Officer believes that conventional penalties may not deter further violations.

Section 96012. Injunctions.

Summary of Section 96012.

Section 96012 cites existing authority for ARB to enjoin violations of this article.

Rationale for Section 96012.

This section is needed to clarify that ARB has authority in existing Health and Safety Code provisions to enjoin violations of its regulations.

Section 96013. Penalties.

Summary of Section 96013.

Section 96013 cites existing authority for ARB to set penalties for violations of its regulations.

Rationale for Section 96013.

This section is needed to clarify that ARB has authority in existing Health and Safety Code provisions to set penalties for violations of its regulations.

Section 96014. Violations.

Summary of Section 96014 (a) through (c).

Subsections (a) through (c) establish a separate violation for each required compliance instrument that has not been surrendered; for each day or portion of a day that each required compliance instrument has not been surrendered; and for each day or portion of a day in which any other violation of the regulations occurs.

Rationale for Section 96014 (a) through (c).

These provisions are necessary so that ARB can set penalties based on the magnitude or duration of the violations of compliance instrument surrender provisions. These surrender provisions are unique to cap-and-trade programs.

Subarticle 16. Other Provisions.

Section 96020. Severability, Effect of Judicial Order.

Summary of Section 96020.

Section 96020 states that that if one provision of the regulations is declared invalid by a court or other authority, the remaining provisions will remain in full force and effect.

Rationale for Section 96020.

This section is necessary because it ensures that if ARB has enacted a provision in the proposed regulatory article that is illegal or unconstitutional, the remaining regulatory provisions remain intact.

Section 96021. Confidentiality.

Summary of Section 96021(a).

Subsection (a) describes that all emissions data submitted to ARB is public information and may not be designated as confidential per reporter's discretion.

Rationale for Section 96021(a).

This provision is necessary to implement the requirements set forth in Health and Safety Code sections 39600 and 39601.

Summary of Section 96021(b).

Subsection (b) describes the confidentiality requirements for all reports and information provided by a covered entity, opt-in cover entity, voluntarily associated entity, and other registered participants to the ARB.

Rationale for Section 96021(b).

This provision is necessary to ensure that the regulated entities understand how reports and information are managed, to ensure compliance with title 17 of the California Code of Regulations, sections 91000 to 91022.

Section 96022. Reserved Provisions.

Summary of Section 96022.

Section 96022 is reserved for future provisions.

Rationale for Section 96022.

Section 96022 is reserved for future provisions.

X REFERENCES

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APPENDIX A
PROPOSED REGULATION ORDER

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Subchapter 10 Climate Change, Article 5, Sections 95800 to 96022, Title 17, California Code of Regulations, to read as follows:

Article 5: CALIFORNIA CAP ON GREENHOUSE GAS EMISSIONS AND MARKET-BASED COMPLIANCE MECHANISMS

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Subarticle 2: Purpose and Definitions

§ 95801. Purpose.

The purpose of this article is to reduce emissions of greenhouse gases associated with entities identified in this article through the establishment, administration, and enforcement of the California Greenhouse Gas Cap-and-Trade Program by applying an aggregate greenhouse gas allowance budget on covered entities and providing a trading mechanism for compliance instruments.

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code.
Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

§ 95802. Definitions.

(a) Definitions. For the purposes of this article, the following definitions shall apply:

(1) "Accounts administrator" means the entity acting in the capacity to administer the accounts identified in this regulation. This may be ARB, or could be an entity ARB enters into a contract with.

(2) "Activity-shifting leakage" means increased GHG emissions or decreased GHG removals that result from the displacement of activities or resources from inside the offset project's boundary to locations outside the offset project's boundary as a result of the offset project activity.

(3) "Additional" means, in the context of offset credits, greenhouse gas emission reductions or removals that exceed any greenhouse gas reduction or removals otherwise required by law, regulation or legally binding mandate, and that exceed any greenhouse gas reductions or

removals that would otherwise occur in a conservative business-as-usual scenario.

(4) "Adverse Offset Verification Statement" means an Offset Verification Statement rendered by a verification body attesting that the verification body cannot say with reasonable assurance that the submitted Offset Project Data Report is free of an offset material misstatement, or that it cannot attest that the Offset Project Data Report conforms to the requirements of this article or applicable Compliance Offset Protocol.

(5) "Allowance" means a limited tradable authorization to emit up to one metric ton of carbon dioxide equivalent.

(6) "Alternate authorized account representative" means the single entity identified during the account application process who may act on behalf of the authorized account representative.

(7) "Annual allowance budget" means the number of California Greenhouse Gas Allowances associated with one year of the California Cap-and-Trade Program in subarticle 6.

(8) "Asset controlling supplier" means any entity that owns or operates electricity generating facilities or serves as an exclusive marketer for certain generating facilities even though it does not own them, and is assigned a supplier-specific identification number and specified source emission factor by ARB for the wholesale electricity procured from its system and imported into California. Asset controlling suppliers include Bonneville Power Administration (BPA) and the two multi-jurisdictional retail providers in California: PacifiCorp and Sierra Pacific Power Company.

(9) "Auction" means the process of selling California Greenhouse Gas Allowances by offering them up for bid, taking bids, and then distributing the allowances to winning bidders.

(10) "Auction purchase limit" means the limit on the number of allowances one entity or a group of affiliated entities may purchase from the share of allowances sold at a quarterly auction.

(11) "Auction reserve price" means a price for allowances below which bids at auction would not be accepted.

(12) "Auction settlement price" means the price announced by the auction administrator at the conclusion of each quarterly auction. It is the price which all successful bidders will pay for their allowances and also the price to be paid to those entities which consigned allowances to the auction.

(13) "Authorized account representative" means an entity approved through the application process outlined in 95832 and legally bind each entity that owns compliance instruments held in the account in all matters pertaining to this article.

(14) "Authorized Project Designee" means an entity authorized by an Offset Project Operator to act on behalf of the Offset Project Operator.

(15) "Balancing Authority" means the responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a balancing authority area, and supports interconnection frequency in real time.

(16) "Balancing Authority Area" means the collection of generation, transmission, and loads within the metered boundaries of a balancing authority. A balancing authority maintains load-resource balance within this area.

(17) "Banking" means the holding of compliance instruments from one compliance period for the purpose of sale or surrender in a future compliance period.

(18) "Beneficial Holding" means the holding of a compliance instrument in the holding account by one entity in which another entity has an ownership interest.

(19) "Biodiesel" means a diesel fuel substitute produced from nonpetroleum renewable resources that meet the registration requirements for fuels and fuel additives established by the U.S. Environmental Protection Agency under section 211 of the Clean Air Act. It includes biodiesel that is all of the following:

(A) Registered as a motor vehicle fuel or fuel additive under 40 CFR Part 70;

(B) A mono-alkyl ester;

(C) Meets American Society for Testing and Material designation ASTM D 6751-08 (*Standard Specification for Biodiesel Fuel Blendstock (B100) for Middle Distillate Fuels, 2008*);

(D) Intended for use in engines that are designated to run on conventional diesel fuel; and

(E) Derived from nonpetroleum renewable resources.

(20) "Biomass" means non-fossilized and biodegradable organic material originating from plants, animals, and microorganisms, including products, by-products, residues, and waste from agriculture, forestry, and related industries as well as the non-fossilized and biodegradable organic fractions of industrial and municipal wastes, including gases and liquids recovered from the decomposition of non-fossilized and biodegradable organic material. For the purpose of this article, biomass includes both California Renewable Portfolio Standard (RPS) eligible and non-eligible biomass as defined by the California Energy Commission.

(21) "Biomass-derived fuels" or "biomass fuels" means fuels derived from biomass.

(22) "Blendstocks" are petroleum products used for blending or compounding into finished motor gasoline. These include RBOB (reformulated blendstock for oxygenate blending) and CBOB (conventional blendstock for oxygenate blending), but exclude oxygenates, butane, and pentanes plus.

(23) "Budget year" means the annual allowance budget assigned pursuant to subarticle 6.

(24) "Business-as-usual scenario" means the set of conditions reasonably expected to occur within the offsets project boundary in the absence of the financial incentives provided by offset credits, taking into account all current laws and regulations, as well as current economic and technological trends.

(25) "Calendar year" means the time period from January 1 through December 31.

(26) "California electricity transmission and distribution system" means the combination of the entire infrastructure within California that delivers electric power from electric generating facilities to end users over single or multiple paths.

(27) "California greenhouse gas emissions allowance" or "CA GHG Allowance" means an allowance issued by ARB and equal to up to one metric ton of CO_2 equivalent.

(28) "Cap" means the total number of California Greenhouse Gas Allowances that the Executive Officer issues over a given period of time.

(29) "Carbon dioxide" or "CO_2" means the most common of the six primary greenhouse gases, consisting on a molecular level of a single carbon atom and two oxygen atoms.

(30) "Carbon dioxide equivalent" or "CO_2 equivalent" or "CO_2e" means the number of metric tons of CO_2 emissions with the same global warming potential as one metric ton of another greenhouse gas.

(31) "Carbon stock" means the quantity of carbon contained in an identified GHG reservoir.

(32) "Cement" means a building material that is produced by heating mixtures of limestone and other minerals or additives at high temperatures in a rotary kiln to form clinker, followed by cooling and grinding with blended additives. Finished cement is a powder used with water, sand, and gravel to make concrete and mortar.

(33) "Cogeneration" means an integrated system that produces electric energy and useful thermal energy for industrial, commercial, or heating and cooling purposes, through the sequential or simultaneous use of the original fuel energy.

(34) "Combustion emissions" means greenhouse gas emissions occurring during the exothermic reaction of a fuel with oxygen.

(35) "Compliance account" means an account created by the accounts administrator for a covered entity or opt-in covered entity with a compliance obligation, to which the entity transfers compliance instruments to meet its annual and triennial compliance obligations.

(36) "Compliance instrument" means an allowance, offset credit or sector-based offset credit. Each compliance instrument can be used to fulfill a compliance obligation equivalent to up to one metric ton of CO_2e.

(37) "Compliance obligation" means the quantity of verified reported emissions for which a covered entity must submit compliance instruments to ARB.

(38) "Compliance offset protocol" means an offset protocol adopted by the Board.

(39) "Compliance period" means the three-year period for which the compliance obligation is calculated for covered entities.

(40) "Conflict of interest" means a situation in which, because of financial or other activities or relationships with other persons or organizations, a person or body is unable or potentially unable to render an impartial Offset Verification Statement of a potential client's Offset Project Data Report, or the person or body's objectivity in performing offset verification services is or might be otherwise compromised.

(41) "Conservative" means, in the context of offsets, utilizing project baseline assumptions, emission factors, and methodologies that are more likely than not to understate net GHG reductions or GHG removal enhancements for an offset project to address uncertainties affecting the calculation or measurement of GHG reductions or GHG removal enhancements.

(42) "Consumer Price Index for All Urban Consumers" means a measure that examines the changes in the price of a basket of goods and services purchased by urban consumers, and is published by the U.S. Bureau of Labor Statistics.

(43) "Counterparty" means the opposite party in a bilateral agreement, contract, or transaction.

(44) "Covered entity" means an entity within California that has one or more of the processes or operations and has a compliance obligation as specified in subarticle 7 of this regulation; and that has emitted, produced, imported, manufactured, or delivered in 2008 or any subsequent year more than the applicable threshold level specified in section 95812 (a) of this rule.

(45) "Crediting baseline" refers to the reduction of absolute GHG emissions below the business-as-usual scenario or reference level across a jurisdiction's entire sector in a sector-based crediting program after the

imposition of greenhouse gas emission reduction requirements or incentives.

(46) "Crediting period" means the pre-determined period for which an offset project will remain eligible to be issued offset credits for verified GHG emission reductions or GHG removal enhancements.

(47) "Data year" means the calendar year in which emissions occurred.

(48) "Deforestation" means direct human-induced conversion of forested land to non-forested land.

(49) "Delivered electricity" means electricity that was distributed from a PSE and received by a PSE or electricity that was generated, transmitted and consumed.

(50) "Diesel fuel" means Distillate Fuel No. 1 and Distillate Fuel No. 2, including dyed and non-taxed fuels.

(51) "Direct GHG emission reduction" means a GHG emission reduction from applicable GHG emission sources, GHG sinks, or GHG reservoirs that are under control of the Offset Project Operator or Authorized Project Designee.

(52) "Direct GHG removal enhancement" means a GHG removal enhancement from applicable GHG emission sources, GHG sinks, or GHG reservoirs under control of the Offset Project Operator or Authorized Project Designee.

(53) "Distillate Fuel No. 1" has a maximum distillation temperature of 550 F at the 90 percent recovery point and a minimum flash point of 100 F and includes fuels commonly known as Diesel Fuel No. 1 and Fuel Oil No. 1, but excludes kerosene. This fuel is further subdivided into categories of sulfur content: High Sulfur (greater than 500 ppm), Low Sulfur (less than or equal to 500 ppm and greater than 15 ppm), and Ultra Low Sulfur (less than or equal to 15 ppm).

(54) "Distillate Fuel No. 2" has a minimum and maximum distillation temperature of 540 F and 640 F at the 90 percent recovery point, respectively, and includes fuels commonly known as Diesel Fuel No. 2 and Fuel Oil No. 2. This fuel is further subdivided into categories of sulfur content: High Sulfur (greater than 500 ppm), Low Sulfur (less than or equal to 500 ppm and greater than 15 ppm), and Ultra Low Sulfur (less than or equal to 15 ppm).

(55) "Distillate fuel No. 4" is a distillate fuel oil made by blending distillate fuel oil and residual fuel oil, with a minimum flash point of 131 F.

(56) "Distillate fuel oil" means a classification for one of the petroleum fractions produced in conventional distillation operations and from crackers and hydrotreating process units. The generic term "distillate fuel oil" includes kerosene, diesel fuels (Diesel Fuels No. 1, No. 2, and No. 4), and fuel oils (Fuel Oils No. 1, No. 2, and No. 4).

(57) "Electrical distribution utility(ies)" means an Investor Owned Utility (IOU) as defined in the Public Utilities Code section and 218, or a local publicly owned electric utility (POU) as defined in Public Utilities Code section 224.3, that provides electricity to retail end users in California.

(58) "Electricity generating facility" means a facility whose sole purpose is to generate electricity and includes one or more electricity generating units at the same location. "Electricity generating facility" does not include a cogeneration facility or self-generation.

(59) "Electricity importers" are marketers and retail providers that hold title to imported electricity. For electricity delivered between balancing authority areas, the entity that holds title to delivered electricity is identified on the NERC E-tag as the purchasing-selling entity (PSE) on the tag's physical path, with the point of receipt located outside the state of California, and the point of delivery located inside the state of California. Federal and state agencies are subject to the regulatory

authority of ARB under this article, and include Western Area Power Administration (WAPA), Bonneville Power Administration (BPA) and California Department of Water Resources (DWR). When PSEs are not subject to the regulatory authority of ARB, including tribal nations, the electricity importer is the immediate down stream purchaser or recipient that is subject to the regulatory authority of ARB.

(60) "Emissions" means the release of greenhouse gases into the atmosphere from sources and processes in a facility, including from the combustion of transportation fuels such as natural gas, petroleum products, and natural gas liquids. In the context of offsets, "emissions" means the release of greenhouse gases into the atmosphere from sources and processes within an offset project boundary.

(61) "Emissions data report" or "greenhouse gas emissions data report" or "report" means the report prepared by an operator or supplier each year and submitted by electronic means to ARB that provides the information required by the regulation for the Mandatory Reporting of Greenhouse Gas Emissions.

(62) "Emissions efficiency benchmark" or "GHG emissions efficiency benchmark" means a performance standard used to evaluate GHG emissions efficiency between and amongst similar facilities or operations in the same industrial sector.

(63) "End user" means, a final purchaser of electricity or natural gas not for the purposes of retransmission or resale In the context of natural gas consumption, an "end user" is the point to which natural gas is delivered for consumption.

(64) "Enforceable" means the authority for ARB to hold a particular party liable and to take appropriate action if any of the provisions of this article are violated.

(65) "Enterer" means an entity that imports motor vehicle fuel, diesel fuel, ethanol, biodiesel, or any other biomass-derived fuel or renewable fuel and who is the importer of record under federal customs law or the owner of fuel upon import if the fuel is not subject to federal customs law.

(66) "Entity" means a person, firm, association, organization, partnership, business trust, corporation, limited liability company, company, or government agency.

(67) "Environmental impact assessment" means a detailed public disclosure statement of potential environmental and socioeconomic impacts associated with a proposed project. Such disclosure is a matter of public record and provides detailed information to public agencies and the general public about the effect that a proposed project is likely to have on the environment and ways in which the significant effects of such a project might be minimized, and to indicate alternatives to such a project.

(68) "Executive Officer" means the Executive Officer of the California Air Resources Board, or his or her delegate.

(69) "External greenhouse gas emissions trading system" or "External GHG ETS" means an administrative system, other than the California Cap-and-Trade Program, that controls greenhouse gas emissions from sources in its program.

(70) "Facility" means any physical property, plant, building, structure, source, or stationary equipment located on one or more contiguous or adjacent properties in actual physical contact or separated solely by a public roadway or other public right-of-way and under common ownership or common control, that emits or may emit any greenhouse gas. Operators of military installations may classify such installations

as more than a single facility based on distinct and independent functional groupings within contiguous military properties.

(71) "First deliverer of electricity" means either the owner or operator of an electricity generating facility in California or an electricity importer.

(72) "Flash point" of a volatile liquid is the lowest temperature at which it can vaporize to form an ignitable mixture in air.

(73) "Fluorinated greenhouse gas" means sulfur hexafluoride (SF_6), nitrogen trifluoride (NF_3), and any fluorocarbon except for controlled substances as defined at 40 CFR Part 82, subpart A and substances with vapor pressures of less than 1 mm of Hg absolute at 25 C. With these exceptions, "fluorinated GHG" includes any hydrofluorocarbon; any perfluorocarbon; any fully fluorinated linear, branched, or cyclic alkane, ether, tertiary amine, or aminoether; any perfluoropolyether; and any hydrofluoropolyether.

(74) "Forest buffer account" means a holding account for forest offset credits. It is used as a general insurance mechanism against unintentional reversals, for all forest offset projects listed under a Compliance Offset Protocol.

(75) "Forest owner" means the owner of any interest in the property involved in a forest offset project, but does not include the holder of a conservation easement. Generally, a forest owner is the owner in fee of the property involved in a forest offset project. In some cases, one entity may be the owner in fee while another entity may have an interest in the trees or the timber on the property, in which case all entities or individuals with interest in the property are collectively considered the forest owners. All forest owner(s) are ultimately responsible for all commitments associated with a forest offset project.

(76) "Fossil fuel" means natural gas, petroleum, coal, or any form of solid, liquid, or gaseous fuel derived from such material, including for

example, consumer products that are derived from such materials and are combusted.

(77) "Fractionates" means the process of separating natural gas liquids into their constituent liquid products.

(78) "Fuel" means solid, liquid, or gaseous combustible material. Volatile organic compounds burned in destruction devices are not fuels unless they can sustain combustion without use of a pilot fuel and such destruction does not result in a commercially useful end product.

(79) "Fuel analytical data" means data collected about fuel usage (including mass, volume, and flow rate) and fuel characteristics (including heating value, carbon content, and molecular weight) to support emissions calculation.

(80) "Fuel supplier" means a supplier of petroleum products, a supplier of biomass-derived transportation fuels, a supplier of natural gas, or a supplier of liquid petroleum gas as specified in MRR.

(81) "Fugitive emissions" means those emissions which are unintentional and could not reasonably pass through a stack, chimney, vent, or other functionally-equivalent opening.

(82) "Gas" means the state of matter distinguished from the solid and liquid states by: relatively low density and viscosity; relatively great expansion and contraction with changes in pressure and temperature; the ability to diffuse readily; and the spontaneous tendency to become distributed uniformly throughout any container.

(83) "Global warming potential" or ""GWP" means the ratio of the time-integrated radiative forcing from the instantaneous release of one kilogram of a trace substance relative to that of one kilogram of a reference gas, i.e., CO_2.

(84) "Greenhouse gas" or "GHG" means carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), sulfur hexafluoride (SF_6),

hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), hydrocarbons, and other fluorinated greenhouse gases as defined in this section.

(85) "Greenhouse gas emission reduction" or "GHG emission reduction" or "greenhouse gas reduction" or "GHG reduction" means a calculated decrease in GHG emissions relative to a project baseline over a specified period of time.

(86) "Greenhouse gas emissions source" or "GHG emissions source" means, in the context of offset credits, any type of emitting activity that releases greenhouse gases into the atmosphere.

(87) "Greenhouse gas removal" or "GHG removal" means the calculated total mass of a GHG removed from the atmosphere over a specified period of time.

(88) "Greenhouse gas removal enhancement" or "GHG removal enhancement" means a calculated increase in GHG removals relative to a project baseline.

(89) "Greenhouse gas reservoir" or "GHG reservoir" means a physical unit or component of the biosphere, geosphere, or hydrosphere with the capability to store, accumulate, or release a GHG removed from the atmosphere by a GHG sink or a GHG captured from a GHG emission source.

(90) "Greenhouse gas sink" or "GHG sink" means a physical unit or process that removes a GHG from the atmosphere.

(91) "HD-5" means a consumer grade of liquefied petroleum gas that contains a minimum of 90% propane, and a maximum of 5% propylene and 5% butanes and ethane.

(92) "HD-10" means liquefied petroleum gas with no more than 10% propylene.

(93) "Hold" in the context of a California compliance instrument, is to have the serial number assigned to that instrument registered into a holding account.

(94) "Hydrocarbon" means a chemical compound containing predominantly carbon and hydrogen.

(95) "Hydrofluorocarbon" or "HFC" means a class of GHGs consisting of hydrogen, fluorine, and carbon.

(96) "Hydrogen" means the lightest of all gases, occurring chiefly in combination with oxygen in water; it exists also in acids, bases, alcohols, petroleum, and other hydrocarbons.

(97) "Imported electricity" means electricity generated outside the state of California and delivered to serve load inside California. Imported electricity includes electricity delivered from a point of receipt located outside the state of California, to the first point of delivery inside the state of California, having a final point of delivery in California. Imported electricity includes electricity imported into California over a multi-jurisdictional retail provider's transmission and distribution system, or electricity imported into California over a balancing authority's transmission and distribution system. Imported electricity includes electricity that is a result of cogeneration outside of California. Imported electricity does not include electricity wheeled through California, which is electricity that is delivered into California with final point of delivery outside California.

(98) "Initial crediting period" means the crediting period that begins with the date that the first GHG emission reductions or GHG removal enhancements took place according to the first offset verification statement that is received by ARB.

(99) "Intentional reversal" means any reversal caused by a forest owner's negligence, gross negligence, or willful intent, including harvesting, development, and harm to the area within the project area.

(100) "Intrastate pipeline" means any pipeline wholly within the state of California that is not regulated as a public utility gas corporation by the California Public Utility Commission (CPUC), not a publicly owned natural gas utility and is not regulated as an interstate pipeline by the Federal Energy Regulatory Commission.

(101) "Interstate pipeline" means any entity that owns or operates a natural gas pipeline delivering natural gas to consumers in the state and is subject to rate regulation by the Federal Energy Regulatory Commission.

(102) "Inventory position" means a contractual agreement with the terminal operator for the use of the storage facilities and terminaling services for the fuel.

(103) "Issue" or "issuance" means, in the context of offset credits, the creation of offset credits equivalent to the number of verified GHG reductions or GHG removal enhancements for an offset project. In the context of allowances, issue means the placement of an allowance in an entity's holding account.

(104) "Kerosene" is a light petroleum distillate with a maximum distillation temperature of 400 F at the 10-percent recovery point, a final maximum boiling point of 572 F, a minimum flash point of 100 F, and a maximum freezing point of -22 F. Included are No. 1-K and No. 2-K, distinguished by maximum sulfur content (0.04 and 0.30 percent of total mass, respectively), as well as all other grades of kerosene called range or stove oil. Kerosene does not kerosene-type jet fuel.

(105) "Lead verifier" means a person that has met all of the requirements in section 95132(b)(2) of MRR and who may act as the lead verifier of an

offset verification team providing offset verification services or as a lead verifier providing an independent review of offset verification services rendered.

(106) "Lead verifier independent reviewer" or "Independent reviewer" means a lead verifier within a verification body who has not participated in conducting offset verification services for an Offset Project Developer or Authorized Project Designee for the current Offset Project Data Report who provides an independent review of offset verification services rendered for an Offset Project Developer or Authorized Project Designee as required in section 95977(e)(2)(C)(xviii).

(107) "Limited Use Holding Account" means an account in which allowances are placed when an entity qualifies for a direct allocation under section 95890. Allowances placed in this account can only be removed for consignment to the auction.

(108) "Linkage" means the approval of compliance instruments from an external greenhouse gas emission trading system (GHG ETS) to meet compliance obligations under this article, and the reciprocal approval of compliance instruments issued by California to meet compliance obligation in an external GHG ETS.

(109) "Liquefied Petroleum Gas" or "LPG" means a flammable mixture of hydrocarbon gases used as a fuel. LPG can be mixtures of primarily propane, primarily butane, or mixtures of propane or butane. LPG includes propane grades, HD-5, HD-10, and commercial grade propane. LPG also includes both odorized and non-odorized liquid petroleum gas, and is also referred to as LGP, GLP, LP-Gas, and propane.

(110) "Listed Industrial Sector" means covered industrial sectors that are eligible for industry assistance specified in Table 8-1 of subarticle 8.

(111) "Mandatory Reporting Regulation" or "MRR" means ARB's Regulation for the Mandatory Reporting of Greenhouse Gas Emissions as set forth in title 17, California Code of Regulations, chapter 1, subchapter 10, article 2 (commencing with section 95100).

(112) "Market index" means any published index of quantities or prices based on results of market transactions.

(113) "Marketer" means a purchasing-selling entity that takes title to wholesale electricity and is not a retail provider.

(114) "Market-shifting leakage," in the context of an offset project, means increased GHG emissions or decreased GHG removals outside an offset project's boundary due to the effects of an offset project on an established market for goods or services.

(115) "Methane" or "CH_4" means a GHG consisting on the molecular level of a single carbon atom and four hydrogen atoms.

(116) "Metric ton" or "MT" means a common international measurement for mass, equivalent to 2,204.6 pounds or 1.1 short tons.

(117) "Monitoring" means, in the context of offset projects, the ongoing collection and archiving of all relevant and required data for determining the project baseline, project emissions, and quantifying GHG reductions or GHG removal enhancements that are attributable to the offset project.

(118) "Multi Jurisdictional Retail Provider" means a retail provider that provides electricity to consumers in California and in one or more other states in a contiguous service territory or from a common power system.

(119) "Municipal solid waste" or "MSW" means solid phase household, commercial/retail, and/or institutional waste, such as yard waste and refuse.

(120) "Natural gas" means a naturally occurring mixture of hydrocarbon and non-hydrocarbon gases found in geologic formations beneath the earth's surface, of which its constituents include methane, heavier hydrocarbons, and carbon dioxide. Natural gas may be field quality (which varies widely) or pipeline quality. For the purposes of this rule, the definition of natural gas includes similarly constituted fuels such as field production gas, process gas, and fuel gas.

(121) "Natural gas liquid" or NGLs, means those hydrocarbons in natural gas that are separated from the gas as liquids through the process of absorption, condensation, adsorption, or other methods at lease separators and field facilities. Generally, such liquids consist of ethane, propane, butanes, and pentanes plus. "Bulk NGLs" refers to mixtures of NGLs that are sold or delivered as undifferentiated product from natural gas processing plants.

(122) "NERC E-tag" means North American Electric Reliability Corporation (NERC) energy tag representing transactions on the North American bulk electricity market scheduled to flow between or across balancing authority areas.

(123) "Notice of delegation" means a formal notice used to delegate authority to make an electronic submission to the accounts administrator.

(124) "Offset credit" means a tradable compliance instrument issued or approved by ARB that represents a GHG reduction or GHG removal enhancement of one metric ton of CO_2e. The GHG reduction or GHG removal enhancement must be real, additional, quantifiable, permanent, verifiable, and enforceable.

(125) "Offset material misstatement" means an error, omission, or misreporting, or aggregation of the three, identified in the course of offset verification services that leads an offset verification team to believe that an Offset Project Data Report contains errors resulting in

an overstatement of the reported total GHG emission reductions or GHG removal enhancements greater than 5%. Errors, omissions, or misreporting, or an aggregation of the three, that result in an understatement of total reported GHG emission reductions or GHG removal enhancements in the Offset Project Data Report is not an offset material misstatement.

(126) "Offset project" means all equipment, materials, items, or actions that are directly related to or have an impact upon GHG reductions, project emissions, or GHG removal enhancements within the offset project boundary.

(127) "Offset project boundary" is defined by and includes all GHG emission sources, GHG sinks or GHG reservoirs that are affected by an offset project and under control of the Offset Project Operator or Authorized Project Designee. GHG emissions sources, GHG sinks or GHG reservoirs not under control of the Offset Project Operator or Authorized Project Designee are not included in the offset project boundary.

(128) "Offset project commencement" means, for an offset project involving physical construction, other work at an offset project site, or installation of equipment or materials, the date of the beginning of construction, work, or installation. For an offset project that involves the implementation of a management activity, "offset project commencement" means the date on which such activity is first implemented.

(129) "Offset Project Data Report" means the report prepared by an Offset Project Operator or Authorized Project Designee each year that provides the information and documentation required by this article or a compliance offset protocol.

(130) "Offset Project Operator" means the entity(ies) with legal authority to implement the offset project.

(131) "Offset Project Registry" means an entity approved by ARB that lists offset projects, collects Offset Project Data Reports, and facilitates verification of Offset Project Data Reports for offset projects being implemented using a Compliance Offset Protocol.

(132) "Offset protocol" means a documented set of procedures and requirements to quantify ongoing GHG reductions or GHG removal enhancements achieved by an offset project and calculate the project baseline. Offset protocols specify relevant data collection and monitoring procedures, emission factors, and conservatively account for uncertainty and activity-shifting and market-shifting leakage risks associated with an offset project.

(133) "Offset verification" means a systematic, independent, and documented process for evaluation of an Offset Project Operator's or Authorized Project Designee's Offset Project Data Report against ARB's Compliance Offset Protocols and this article for calculation and reporting GHG baseline emissions, project emissions, GHG reductions, or GHG removal enhancements.

(134) "Offset verification services" means services provided during verification as specified in section 95977, including reviewing an Offset Project Operator's or Authorized Project Designee's Offset Project Data Report, verifying its accuracy according to the standards specified in this article and applicable Compliance Offset Protocol, assessing the Offset Project Operator's or Authorized Project Designee's compliance with this article and applicable Compliance Offset Protocol, and submitting an Offset Verification Statement to ARB or an Offset Project Registry.

(135) "Offset verification statement" means the final statement rendered by a verification body attesting whether an Offset Project Operator's or Authorized Project Designee's Offset Project Data Report is free of an offset material misstatement, and whether the Offset Project Data Report conforms to the requirements of this article and applicable Compliance Offset Protocol.

(136) "Offset verification team" means all of those working for a verification body, including all subcontractors, to provide verification services for an Offset Project Operator or Authorized Project Designee.

(137) "Operational control" for a facility subject to this article means the authority to introduce and implement operating, environmental, health, and safety policies. In any circumstance where this authority is shared among multiple entities, the entity holding the permit to operate from the local air pollution control district or air quality management district is considered to have operational control for purposes of this article.

(138) "Operator" means the entity, including an owner, having operational control of a facility, or other entity from which an emissions data report is required under article 2, section 95104, title 17, Greenhouse Gas Emissions Data Report. For onshore petroleum and natural gas production, the operator is the operating entity listed on the state well drilling permit, or a state operating permit for wells where no drilling permit is issued by the state.

(139) "Opt-in Covered Entity" means an entity that meets the requirements of 95811 that does not exceed the inclusion thresholds set forth in section 95812 and may elect to voluntarily opt-in to the cap-and-trade program and be willing to be subject to the requirements set forth in this article.

(140) "Oxidation" means a reaction in which the atoms in an element lose electrons and the valence of the element is correspondingly increased.

(141) "Ozone Depleting Substances" or "ODS" means a compound that contributes to stratospheric ozone depletion.

(142) "Perfluorocarbons" or "PFCs" means a class of greenhouse gases consisting on the molecular level of carbon and fluorine.

(143) "Permanent" means, in the context of offset credits, either that GHG reductions or GHG removal enhancements are not reversible, or when GHG reductions or GHG removal enhancements may be reversible, that mechanisms are in place to replace any reversed GHG emission reductions or GHG removal enhancements to ensure that all credited reductions endure for a period that is comparable to the atmospheric lifetime of an anthropogenic CO_2 emission.

(144) "Permanent Retirement Registry" means the publicly available registry in which the Executive Officer will record the serial numbers of the retired compliance instruments.

(145) "Petroleum" means oil removed from the earth and the oil derived from tar sands, and/or shale.

(146) "Petroleum refinery" or "refinery" means any facility engaged in producing gasoline, gasoline blending stocks, naphtha, kerosene, distillate fuel oils, residual fuel oils, lubricants, or asphalt (bitumen) through distillation of petroleum or through re-distillation, cracking, or reforming of unfinished petroleum derivatives. Facilities that distill only pipeline transmix (off-spec material created when different specification products mix during pipeline transportation) are not petroleum refineries, regardless of the products produced.

(147) "Point of delivery" means the point on an electricity transmission or distribution system where a deliverer makes electricity available to a receiver or available to serve load. This point can be an interconnection with another system or a substation where the transmission provider's transmission and distribution systems are

connected to another system, or a distribution substation where electricity is imported into California over a multi-jurisdictional retail provider's distribution system.

(148) "Point of receipt" means the point on an electricity transmission or distribution system where an electricity receiver receives electricity from a deliverer. This point can be an interconnection with another system or a substation where the transmission provider's transmission and distribution systems are connected to another system.

(149) "Portable" means designed and capable of being carried or moved from one location to another. Indications of portability include wheels, skids, carrying handles, dolly, trailer, or platform. Equipment is not portable if any one of the following conditions exists:

(A) The equipment is attached to a foundation;

(B) The equipment or a replacement resides at the same location for more than 12 consecutive months;

(C) The equipment is located at a seasonal facility and operates during the full annual operating period of the seasonal facility, remains at the facility for at least two years, and operates at that facility for at least three months each year; or

(D) The equipment is moved from one location to another in an attempt to circumvent the portable residence time requirements of this definition.

(150) "Position holder" means an entity that holds an inventory position in motor vehicle fuel, ethanol, distillate fuel, biodiesel, or renewable diesel as reflected in the records of the terminal operator or a terminal operator that owns motor vehicle fuel or diesel fuel in its terminal.

(151) "Positive Offset Verification Statement" means an Offset Verification Statement rendered by a verification body attesting that the verification body can say with reasonable assurance that the submitted Offset

Project Data Report is free of an offset material misstatement and that the Offset Project Data Report conforms to the requirements of this article and applicable Compliance Offset Protocol.

(152) "Power" means electricity, except where the context makes clear that another meaning is intended.

(153) "Proceeds" means monies generated as a result of an auction.

(154) "Process" means the intentional or unintentional reactions between substances or their transformation, including the chemical or electrolytic reduction or metal ores, the thermal decomposition of substances, and the formation of substances for use as product or feedstock.

(155) "Process emissions" means the emissions from industrial processes (e.g., cement production, ammonia production) involving chemical or physical transformations other than fuel combustion. For example, the calcination of carbonates in a kiln during cement production or the oxidation of methane in an ammonia process results in the release of process CO_2 emissions to the atmosphere. Emissions from fuel combustion to provide process heat are not part of process emissions, whether the combustion is internal or external to the process equipment.

(156) "Producer" means a person who owns, leases, operates, controls, or supervises a California production facility.

(157) "Professional judgment" means the ability to render sound decisions based on professional qualifications and relevant greenhouse gas accounting and auditing experience.

(158) "Project baseline" means, in the context of a specific offset project, a conservative estimate of business-as-usual GHG emission reductions or GHG removal enhancements for the offset project's GHG emission

sources, GHG sinks, or GHG reservoirs within the offset project boundary.

(159) "Project emissions" means any GHG emissions associated with the implementation of an offset project that must be accounted for in the Offset Project Data Report.

(160) "Propane" is a paraffinic hydrocarbon with molecular formula C_3H_8.

(161) "Property right" means any type of right to specific property whether it is personal or real property, tangible or intangible.

(162) "Public utility gas corporation" is a gas corporation defined in California Public Utilities Code section 222 that is also a public utility as defined in California Public Utilities Code section 216.

(163) "Publicly owned natural gas utility" means a municipality or municipal corporation, a municipal utility district, a public utility district, or a joint powers authority that includes one or more of these agencies that furnishes natural gas services to end users.

(164) "Purchase limit" means the maximum percentage of allowances that may be purchased by an entity of a group of affiliated entities at an allowance auction.

(165) "Purchasing-selling entity" or "PSE" means the functional entity that purchases or sells, and takes title to, energy, capacity, and reliability-related services. A PSE is identified on a NERC E-tag for each physical path segment.

(166) "Qualified Positive Offset Verification Statement" means an Offset Verification Statement rendered by a verification body attesting that the verification body can say with reasonable assurance that the submitted Offset Project Data Report is free of an offset material misstatement, but the Offset Project Data Report may include one or more nonconformance(s) with the quantification, monitoring, or metering

requirements of this article and applicable Compliance Offset Protocol which do not result in an offset material misstatement.

(167) "Qualified Positive Verification Statement" means a statement rendered by a verification body attesting that the verification body can say with reasonable assurance that the submitted emissions data report is free of material misstatement, but the emissions data report may include one or more nonconformance(s) with the requirements of this article which do not result in a material misstatement.

(168) "Quantifiable" means, in the context of offset projects, the ability to accurately measure and calculate GHG reductions or GHG removal enhancements relative to a project baseline in a reliable and replicable manner for all GHG emission sources, GHG sinks, or GHG reservoirs included within the offset project boundary, while accounting for uncertainty and activity-shifting leakage and market-shifting leakage.

(169) "Quantitative usage limit" means a limit on the percentage of an entity's compliance obligation that may be met by surrendering offset credits, sector-based credits, or other compliance instruments designated to be subject to the limit under this article.

(170) "Rack" means a mechanism for delivering motor vehicle fuel or diesel from a refinery or terminal into a truck, trailer, railroad car, or other means of non-bulk transfer.

(171) "Radiative forcing" means the change in the net vertical irradiance at the atmospheric boundary between the troposphere and the stratosphere due to an internal change or a change in the external forcing of the climate system such as a change in the concentration of carbon dioxide or the output of the Sun.

(172) "Real" means, in the context of offset projects, that GHG reductions or GHG enhancements result from a demonstrable action or set of actions, and are quantified using appropriate, accurate, and

conservative methodologies that account for all GHG emissions sources, GHG sinks, and GHG reservoirs within the offset project boundary and account for uncertainty and the potential for activity-shifting leakage and market-shifting leakage.

(173) "Reasonable assurance" means a high degree of confidence that submitted data and statements are valid.

(174) "Reference Level" means the quantity of GHG emission equivalents that have occurred during the normal course of business or activities during a designated period of time within the boundaries of a defined sector and a defined jurisdiction.

(175) "Reformulated Gasoline Blendstock for Oxygenate Blending" or "RBOB" has the same meaning as defined in title 13 of the California Code of Regulations, section 2260(a).

(176) "Register" in the context of a compliance instrument means the act of entering the serial number of a compliance instrument into an account.

(177) "Registrant" refers to an entity that has completed the process for registration.

(178) "Registry Services" means all services provided by an ARB approved Offset Project Registry in section 95987.

(179) "Renewable energy" means energy from sources that constantly renew themselves or that are regarded as practically inexhaustible. Renewable energy includes energy derived from solar, wind, geothermal, hydroelectric, wood, biomass, tidal power, sea currents, and ocean thermal gradients.

(180) "Reporting year" means data year.

(181) "Reserve price" see "Auction reserve price."

(182) "Reserve Sale Administrator" means the operator of sales from the Allowance Price Containment reserve account, which may be the Executive Officer or an entity designated by the Executive Officer.

(183) "Retail provider" means an entity that provides electricity to retail end users in California and is an electric corporation as defined in Public Utilities Code section 218, electric service provider as defined in Public Utilities Code section 218.3, local publicly owned electric utility as defined in Public Utilities Code section 224.3, a community choice aggregator as defined in Public Utilities Code section 331.1, or the Western Area Power Administration. For purposes of this article, electrical cooperatives, as defined by Public Utilities Code section 2776, are excluded.

(184) "Retire" or "retired" or "retirement" means that the serial number for a compliance instrument is registered into the Retirement Compliance Account. Compliance instruments registered into this account cannot be used for further compliance.

(185) "Reversal" means a GHG emission reduction or GHG removal enhancement for which ARB has issued an offset credit that is subsequently released or emitted back into the atmosphere due to any intentional or unintentional circumstance.

(186) "Sector" or "sectoral," when used in conjunction with sector-based crediting programs, means a group or subgroup of an economic activity, or a group or cross-section of a group of economic activities, within a jurisdiction.

(187) "Sector-based crediting program" is a GHG emissions-reduction crediting mechanism established by a country, region, or subnational jurisdiction in a developing country and covering a particular economic sector within that jurisdiction. A program's performance is based on achievement toward an emissions-reduction target for the particular sector within the boundary of the jurisdiction.

(188) "Sector-based offset credit" means a credit issued from a sector-based crediting program once the crediting baseline for a sector has been reached.

(189) "Self-generation of electricity" means electricity dedicated to serving an electricity user on the same location as the generator. The system may be operated directly by the electricity user or by an entity with a contractual arrangement.

(190) "Serial number" means a unique number assigned to each compliance instrument for identification.

(191) "Sequestration" means the removal and storage of carbon from the atmosphere in GHG sinks or GHG reservoirs through physical or biological processes.

(192) "Source" means greenhouse gas source; any physical unit, process, or other use or activity that releases a greenhouse gas into the atmosphere.

(193) "Specified source of electricity" or "specified source" means a facility or unit which is permitted to be claimed as the source of imported electricity delivered by an electricity importer. The electricity importer must have either full or partial ownership in the facility/unit or a written contract to procure electricity generated by that facility/unit. Specified facilities/units include cogeneration systems. Specified source also means electricity procured from an asset-controlling supplier recognized by ARB.

(194) "Standing live carbon stocks" means the above ground carbon in live tree biomass. Live trees include the bole, stem, branches, roots, and leaves or needles.

(195) "Stationary" means neither portable nor self propelled, and operated at a single facility.

(196) "Supplier" means a producer, importer, or exporter of a fossil fuel or an industrial greenhouse gas.

(197) "Terminal" means a motor vehicle fuel or diesel fuel storage and distribution facility that is supplied by pipeline or vessel, and from which motor vehicle fuel may be removed at a rack. "Terminal" includes a fuel production facility where motor vehicle fuel is produced and stored and from which motor vehicle fuel may be removed at a rack.

(198) "Transfer" of a compliance instrument means the removal of the serial number of a compliance instrument from one account and placement into another account.

(199) "Tribal Nation" means those Native American tribes in the United States and listed in the Federal Register.

(200) "Unintentional reversal" means any reversal, including wildfires or disease, that is not the result of the forest owner's negligence, gross negligence, or willful intent.

(201) "Unspecified source of electricity" or "unspecified source" means electricity generation that cannot be matched to a specific electricity generating facility or electricity generating unit or matched to an asset-controlling supplier recognized by ARB. Unspecified sources contribute to the bulk system power pool and typically are dispatchable, marginal resources that do not serve baseload.

(202) "Vented emissions" means intentional or designed releases of CH_4 or CO_2 containing natural gas or hydrocarbon gas (not including stationary combustion flue gas), including process designed flow to the atmosphere through seals or vent pipes, equipment blowdown for maintenance, and direct venting of gas used to power equipment (such as pneumatic devices).

(203) "Verifiable" means that an Offset Project Data Report assertion is well documented and transparent such that it lends itself to an objective review by an accredited verification body.

(204) "Verification body" means a firm accredited by ARB, which is able to render an offset verification statement and provide offset verification services for Offset Project Operators or Authorized Project Designees subject to providing an Offset Project Data Report under this article.

(205) "Verifier" means an individual accredited by ARB to carry out offset verification services as specified in section 95977.

(206) "Vintage year" means the budget year to which an individual Californian GHG allowance is assigned pursuant to subarticle 6.

(207) "Voluntarily Associated Entity" means any entity which does not meet the requirements of section 95811 in this article that intends to voluntarily retire compliance instruments in the cap-and-trade program.

(b) For the purposes of sections 95801 through 96022, the following acronyms apply:

(1) "AB 32" means Assembly Bill 32, the California Global Warming Solutions Act of 2006.

(2) "ARB" means the California Air Resources Board.

(3) "BAU" means business as usual.

(4) "BPA" means Bonneville Power Administration.

(5) "CAR" means Climate Action Reserve.

(6) "CEC" means California Energy Commission.

(7) "CFR" means Code of Federal Regulations.

(8) "CH_4" means methane.

(9) "CO_2" means carbon dioxide.

(10) "CO_2e" means carbon dioxide equivalent.

(11) "CRT" means Climate Reserve Tonne.

(12) "DWR" means California Department of Water Resources.

(13) "F" means Fahrenheit.

(14) "GHG" means greenhouse gas.

(15) "GHG ETS" means greenhouse gas emissions trading system.

(16) "GWP" means global warming potential.

(17) "HFC" means hydrofluorocarbon.

(18) "LPG" means liquefied petroleum gas.

(19) "MMBtu" means one million British thermal units.

(20) "MRR" means the Air Resources Board's Regulation for the Mandatory Reporting of Greenhouse Gas Emissions.

(21) "Mscf" means million standard cubic feet.

(22) "MWh " means megawatt-hour.

(23) "MT" means metric tons.

(24) "NAICS" means North American Industry Classification System.

(25) "NGLs" means natural gas liquids.

(26) "NERC" means North American Electric Reliability Corporation.

(27) "N_2O" means "nitrous oxide."

(28) "PFC" means perfluorocarbon.

(29) "PSE" means purchasing-selling entity.

(30) "PUC" means the Public Utilities Code.

(31) "REDD" means reducing emissions from deforestation and degradation.

(32) "SAR" means the Intergovernmental Panel on Climate Change's Second Assessment Report.

(33) "SCF" means standard cubic foot.

(34) "SF_6" means sulfur hexafluoride.

(35) "WAPA" means Western Area Power Administration.

(36) "WCI" means Western Climate Initiative.

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code.

Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

Subarticle 3: Applicability

This article applies to all of the entities identified in this subarticle.

§ 95810. Covered Gases.

This article applies to the following greenhouse gases: carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), sulfur hexafluoride (SF_6), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), nitrogen trifluoride (NF_3), and other fluorinated greenhouse gases.

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code.
Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

§ 95811. Covered Entities.

This article applies to all of the following entities with associated GHG emissions pursuant to section 95812:

(a) Operators of Facilities. The operator of a facility within California that has one or more of the following processes or operations:

(1) Cement production;

(2) Cogeneration;

(3) Glass production;

(4) Hydrogen production;

(5) Iron and steel production;

(6) Lime manufacturing;

(7) Nitric acid production;

(8) Oil and natural gas systems;

(9) Petroleum refining;

(10) Pulp and paper manufacturing;

(11) Self-generation of electricity; or

(12) Stationary combustion.

(b) First Deliverers of Electricity.

(1) Electricity generating facilities: the operator of an electricity generating facility located in California; or

(2) Electricity importers.

(c) Suppliers of Natural Gas. An entity that distributes or uses natural gas in California as described below:

(1) A public utility gas corporation operating in California;

(2) A publicly owned natural gas utility operating in California; or

(3) The operator of an intrastate pipeline not included in section 95811(c)(1) or section 95811(c)(2) that distributes natural gas directly to end users.

(d) Suppliers of RBOB and Distillate Fuel Oil. A position holder of one or more of the following fuels, or an enterer that imports one or more of the following fuels into California:

(1) RBOB;

(2) Distillate Fuel Oil No. 1;

(3) Distillate Fuel Oil No. 2.

(e) Suppliers of Liquefied Petroleum Gas.

(1) The operator of a refinery that produces liquid petroleum gas in California.

(2) The operator of a facility that fractionates natural gas liquids to produce liquid petroleum gas.

(3) A consignee of liquefied petroleum gas into California.

(f) Sections 95811(c), (d), and (e) apply to suppliers of blended fuels that contain the fuels listed above.

(g) Suppliers of carbon dioxide (CO_2).

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code.
Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

§ 95812. Inclusion Thresholds for Covered Entities.

(a) The inclusion threshold for each covered entity is based on the subset of greenhouse gas emissions that generate a compliance obligation for that entity as specified in section 95852. Reported or reported and verified annual emissions could be either reported or verified pursuant to ARB Regulation for the Mandatory Reporting of Greenhouse Gas Emissions or U.S. Environmental Protection Agency (EPA) Final Rule on Mandatory Reporting of Greenhouse Gases.

(b) If an entity's aggregated, reported, or verified annual emissions in any data year from 2008 to 2010 from the categories specified in section 95851(a) equal or exceed the thresholds identified below, that entity is classified as a covered entity as of January 1, 2012 and for all future years until any requirement set forth in section 95812(e) is met.

(1) Operators of Facilities. The threshold for a facility is 25,000 metric tons of CO_2e per data year.

(2) First Deliverers of Electricity.

(A) Electricity Generating Facilities. The threshold for an electricity generating facility is based on the annual emissions from which the electricity originated. The threshold for an electricity generating facility is 25,000 metric tons of CO_2e per data year.

(B) Electricity importers of specified sources of electricity. The threshold for an electricity importer from specified sources is based on the annual emissions of the electricity generating facility from which the imported electricity originated. The

threshold for an electricity importer from a specified source which emits 25,000 metric tons of CO_2e per year is zero.

(C) Electricity importers of unspecified sources of electricity. The threshold for electricity delivered from unspecified sources is zero.

(c) The threshold for a carbon dioxide supplier is based on the sum of its imported and exported carbon dioxide into/out of California. The threshold is 25,000 metric tons of CO_2e per year.

(d) If an entity's annual, reported, and verified emissions from any data year between 2011-2014 equal or exceed the thresholds identified below from the categories specified in section 95851(b), that entity is classified as a covered entity as of January 1, 2015, for the year in which the threshold is reached and for all future years until any requirement set forth in section 95812(e) is met.

(1) Fuel Suppliers. The threshold for a fuel supplier is 25,000 metric tons of CO_2e annually from the emissions of GHG that would result from full combustion or oxidation of the quantities of the fuels, identified in section 95811(c) through (f), that are imported and/or delivered to California.

(2) Electricity importers. The threshold for an electricity importer of specified or unspecified source of electricity is zero as of January 1, 2015.

(e) Effect of Reduced Emissions on an Entity's Compliance Obligation. A covered entity continues to have a compliance obligation for each data year of a compliance period, until the following compliance period after one of the following conditions occurs:

(1) Annual reports demonstrate GHG emissions less than 25,000 metric tons of CO_2e per year during one entire compliance period;

(2) A covered entity shuts down all processes, units, and supply operations subject to reporting, in which case an emissions data report must be submitted for the year in which a facility or supplier's GHG-emitting processes and operations ceased to operate and for the first full year of non-operation following a permanent shutdown. The verification requirements in section 95103 of the Mandatory Reporting Requirements do not apply to the first full year of non-operation following a permanent shutdown.

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code.
Reference: Sections 38530, 38560.5, 38564. 38565, 38570 and 39600, Health and Safety Code.

§ 95813. Opt-In Covered Entities.

(a) An entity that meets the requirements of section 95811, but does not exceed the inclusion thresholds set forth in section 95812 may elect to voluntarily opt-in to the cap-and-trade program.

(b) An entity that voluntarily elects to participate in this program under this section must submit its request to the Executive Officer for approval pursuant to subarticle 5, section 95830(c). The Executive Officer shall evaluate such applications and designate approved applicants as opt-in covered entities.

(c) An opt-in covered entity is subject to all reporting, verification, and compliance obligations that apply to covered entities.

(d) An opt-in covered entity may be eligible to receive freely allocated allowances subject to subarticles 8 and 9.

(e) Opt-in participation shall not affect the allowance budgets set forth in subarticle 6.

(f) Opting out. After the end of any given compliance period an opt-in covered entity may choose to opt out of the program provided its annual emission levels for any data year remain below the inclusion thresholds set forth in section 95812. An entity choosing to opt out of the program must either fulfill its compliance obligations as required pursuant to subarticle 7 or surrender allowances equivalent to all the directly allocated allowances it has received from the budget years for the compliance period in question. An opt-in covered entity that wishes to opt-out of this program must apply to the Executive Officer for approval pursuant to subarticle 5.

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code.
Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

§ 95814. Voluntarily Associated Entities and Other Registered Participants.

(a) Voluntarily Associated Entities (VAE).

(1) An entity not identified as a covered entity or opt-in covered entity that intends to hold California compliance instruments may apply to the Executive Officer pursuant to section 95830(c) for approval as a voluntarily associated entity.

(2) The following entities may qualify as voluntarily associated entities:

(A) An entity that does not meet the requirements of sections 95811 and 95813 that intends to purchase, hold, sell, or voluntarily retire compliance instruments; or

(B) An entity operating an offset project that is registered with ARB pursuant to subarticle 13.

(b) Other Registered Participants.

(1) The following entities do not qualify to hold compliance instruments but may qualify as a Registered Participant to serve in the following functions:

(A) A verifier pursuant to section 95978;

(B) A verification body pursuant to section 95978;

(C) Offset Project Registries; or

(D) Other third-party registrants pursuant to subarticle 14.

(2) To qualify as a Registered Participant the entity must obtain registration approval from the Executive Officer pursuant to section 95830 (c).

(c) A registered entity that has had its holding account revoked pursuant to section 95831(b) may not hold compliance instruments or register with the accounts administrator in the cap-and-trade program in any capacity:

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code.
Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

Subarticle 4: Compliance Instruments

§ 95820. Compliance Instruments Issued by the Air Resources Board.

(a) California Greenhouse Gas Emissions Allowances.

(1) The Executive Officer shall create California GHG allowances pursuant to the schedule set forth in subarticle 6.

(2) The Executive Officer shall assign each California GHG allowance a unique serial number that indicates the annual allowance budget from which the allowance originates

(3) Within 15 days of the effective date of this article the Executive Officer shall place these allowances into a holding account under the control of the Executive Officer pursuant to section 95831(c).

(b) Offset Credits Issued by ARB.

(1) The Executive Officer shall issue and register offset credits pursuant to the requirements of subarticle 13.

(2) Surrender of offset credits shall be subject to the quantitative usage limit set forth in section 95995.

(c) Each compliance instrument issued by the Executive Officer represents a limited authorization to emit up to one metric ton in CO_2e of any greenhouse gas specified in section 95810, subject to all applicable limitations specified in this article. No provision of this article may be construed to limit the authority of the Executive Officer to terminate or limit such authorization to emit. A compliance instrument issued by the Executive Officer does not constitute property or a property right.

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code.
Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

§ 95821. Compliance Instruments Issued by Approved Programs.

The following compliance instruments may be used to meet a compliance obligation under this article:

(a) allowances specified in section 95942(b) and issued by a program approved by ARB pursuant to section 95941;

(b) offset credits specified in section 95942(c) and issued by a program approved by ARB pursuant to section 95941;

(c) offset credits recognized for purposes of early action pursuant to section 95990; and

(d) sector-based offset credits recognized pursuant to subarticle 14.

(e) compliance instruments specified in section 95821(b) through (d) are subject to the quantitative usage limit set forth in section 95995.

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code.
Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

Subarticle 5: Registration and Accounts

§ 95830. Registration with ARB.

(a) The Executive Officer shall serve as accounts administrator or may contract with an entity to serve as accounts administrator.

(b) An entity cannot hold an ARB-issued compliance instrument until the Executive Officer approves the entity's registration with ARB or the entity is registered with an external program approved by ARB pursuant to subarticles 12 or 14.

(c) Requirements for Registration.

(1) An entity must complete an application that contains the following information:

(A) Name and type of organization;

(B) Statement of basis for qualifying for registration pursuant to sections 95811, 95813, or 95814;

(C) Identification of all other entities registered pursuant to this subarticle with whom the entity has a direct or indirect corporate association pursuant to section 95914, and a brief description of the association;

(D) Identification of all entities registered pursuant to this subarticle for whose benefit the entity holds compliance instruments.

(E) Applicants may be denied registration based on (i) information provided; or (ii) if the Executive Officer determines the applicant has provided false or misleading information, or has withheld information pertinent to its application.

(2) An entity must designate an authorized account representative pursuant to section 95832.

(d) Registration Deadlines.

(1) An entity that meets or exceeds the inclusion thresholds in section 95812 must register with the accounts administrator pursuant to this section:

(A) within 45 calendar days of the reporting deadline contained in the MRR if the entity is not a covered entity as of January 1, 2012; or

(B) within 30 calendar days of the effective date of this regulation for an entity that exceeds the inclusion thresholds in section 95812 for any data year 2008 through 2010.

(2) An opt-in covered entity must register with the accounts administrator pursuant to section 95830:

(A) within 30 calendar days of the effective date of this regulation for an entity voluntarily electing to be subject to a compliance obligation pursuant to section 95813 during 2012;

(B) by November 30 of the calendar year prior to the first year in which it voluntarily elects to be subject to a compliance obligation pursuant to section 95813.

(3) Any voluntarily associated entity that intends to hold an ARB-issued compliance instrument must register with the accounts administrator pursuant to section 95830 prior to acquiring such compliance instruments.

(e) Completion of Registration. Registration is completed when the Executive Officer approves the registration and informs the entity and the accounts administrator of the approval.

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code.

Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

§ 95831. Account Types.

(a) Creation of Holding and Compliance Accounts.

(1) The Executive Officer shall not approve registration for more than one set of accounts for an entity.

(2) Holding Accounts. When the Executive Officer approves a registration for a covered entity, an opt-in covered entity, or a voluntarily associated entity, the accounts administrator will create a holding account for the registrant.

(3) Limited Use Holding Accounts. When an entity qualifies for a direct allocation under section 95890, the accounts administrator will create a limited use holding account for the entity that shall be subject to the following restrictions:

(A) the entity may not transfer compliance instruments from other accounts into the limited use holding account; and

(B) the entity may not transfer compliance instruments from the limited use holding account to any account other than the Auction Holding Account.

(4) Compliance Accounts. When a covered entity or opt-in covered entity completes the registration process, the account administrator will create a compliance account for the covered entity.

(A) A covered entity or opt-in covered entity may transfer compliance instruments to its compliance account at any time.

(B) A compliance instrument transferred into a compliance account may not be removed by the covered entity.

(b) Suspension, Revocation, or Restriction of Holding Accounts.

(1) The Executive Officer may revoke or suspend the registration and accounts of a voluntarily associated entity or opt-in covered entity for violations of this article.

(A) If registration is revoked or suspended the entity must sell or voluntarily retire all compliance instruments in its holding account within 30 days of revocation.

(B) If registration is revoked or suspended and the entity fails to sell or voluntarily retire all compliance instruments in its holding account within 30 days of revocation, the accounts administrator will transfer the remaining instruments into the Auction Holding Account for sale at auction on behalf of the entity pursuant to section 95910(d).

(2) The holding account of any entity may be restricted by the Executive Officer by either of the following:

(A) to hold a number of compliance instruments less than the holding limit established in section 95920(b); or

(B) to limit or prohibit transfers in or out of the holding account.

(c) Accounts under the Control of the Executive Officer. The accounts administrator will create and maintain the following accounts under the control of the Executive Officer:

(1) A holding account to be known as the Allocation Holding Account into which the serial numbers of compliance instruments will be registered when the compliance instruments are created;

(2) A holding account known as the Auction Holding Account into which allowances are transferred to be sold at auction from:

(A) the Allocation Holding Account;

(B) the holding accounts of those entities for which allowances are being auctioned on consignment pursuant to 95831(b)(1)(B); and

(C) the limited use holding accounts of those entities consigning allowances to auction pursuant to subarticle 8.

(3) A holding account to be known as the Retirement Account to which the Executive Officer will transfer compliance instruments from compliance accounts. Alternatively, entities may voluntarily retire compliance instruments by transferring the serial numbers of instruments they are retiring to the Retirement Account.

(A) When compliance instruments are registered into the Retirement Account, these compliance instruments cannot be returned to any other holding or compliance account.

(B) When compliance instruments are registered into the Retirement Account, any external ETS to which California links will be informed of the retirements.

(C) The Executive Officer will record the serial numbers of the retired instruments to a publicly available Permanent Retirement Registry.

(4) A holding account to be known as the Allowance Price Containment Reserve Account:

(A) Into which the serial numbers of allowances allocated by ARB for auction that remain unsold at auction will be transferred.

(B) Into which the serial numbers of allowances directly allocated to the Allowance Price Containment Reserve under subarticle 8 will be transferred.

(C) Into which the serial numbers of allowances submitted to fulfill an entity's excess emissions obligation pursuant to section 95857(c) will be transferred.

(D) From which the Executive Officer will withdraw allowances to sell to covered entities pursuant to section 95913.

(5) A holding account to be known as the Forest Buffer Account:

(A) Into which a percentage, of offset credits issued by ARB for Compliance Offset Protocol Forest Projects pursuant to section 95983(a) will be transferred. The percentage is determined pursuant to the Compliance Offset Protocol Forest Projects U.S.,

(B) From which the Executive Officer may withdraw offset credits in the case of unintentional project reversals pursuant to 95983(d)(2) and 95985(f). These offset credits will be transferred to the Retirement Holding Account.

(6) Reserved for Voluntary Renewable Energy Allowance Set-Aside Account.

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code.
Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

§ 95832. Designation of Authorized Account Representative.

(a) An application for an account must designate a single authorized account representative and a single alternate authorized account representative who may act on behalf of the authorized account representative. The agreement by which the alternate authorized account representative is selected shall include a procedure for authorizing the alternate authorized account representative to act in lieu of the authorized account representative. A complete application for an account shall be submitted to the accounts administrator and shall include the following elements:

(1) Name, address, E-mail address, telephone number, and facsimile transmission number of the authorized account representative and any alternate authorized account representative;

(2) Organization name;

(3) A list of all entities subject to a binding agreement for the authorized account representative or any alternate authorized account representative to represent their ownership interest with respect to the compliance instruments held in the account, including a statement of each beneficial owner's percentage ownership interest and a statement of affiliations between beneficial owners;

(4) The following certification statement by the authorized account representative and any alternate authorized account representative: "I certify that I was selected as the authorized account representative or the alternate authorized account representative, as applicable, by an agreement that is binding on all persons who have an ownership interest with respect to compliance instruments held in the account. I certify that I have all the necessary authority to carry out the duties and responsibilities contained in title 17, article 5, sections 95800 et seq. on behalf of such persons and that each such person shall be fully bound by my representations, actions, inactions, or submissions and by any order or decision issued to me by the accounts administrator or a court regarding the account";

(5) The signature of the authorized account representative and any alternate authorized account representative and the dates signed.

(b) Unless otherwise required by the Executive Officer, documents of agreement referred to in the application for an account shall not be submitted to the accounts administrator. The accounts administrator shall not be under any obligation to review or evaluate the sufficiency of such documents, if submitted.

(c) Authorization of authorized account representative. Upon receipt by the accounts administrator of a complete application for an account under section 95830(c):

(1) The accounts administrator will establish an account or accounts for the person or persons for whom the application is submitted pursuant to section 95831.

(2) The authorized account representative and any alternate authorized account representative for the account shall represent and, by his or her representations, actions, inactions, or submissions, legally bind each entity that owns compliance instruments held in the account in all matters pertaining to this article, notwithstanding any agreement between the authorized account representative or any alternate authorized account representative and such entity.

(3) Any such entity shall be bound by any decision or order issued to the authorized account representative or any alternate authorized account representative by the Executive Officer or a court regarding the account. Any representation, action, inaction, or submission by any alternate authorized account representative shall be deemed to be a representation, action, inaction, or submission by the authorized account representative.

(d) Each submission concerning the account shall be submitted, signed, and certified by the authorized account representative or any alternate authorized account representative for the entities that own compliance instruments held in the account. Each such submission shall include the following certification statement by the authorized account representative or any alternate authorized account representative: "I am authorized to make this submission on behalf of the entities that own the compliance instruments held in the account. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my

knowledge and belief true, accurate, and complete. I consent to the jurisdiction of California and its courts for purposes of enforcement of the laws, rules and regulations pertaining to title 17, article 5, sections 95800 et seq., and I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment."

(e) The accounts administrator will accept or act on a submission concerning the account only if the submission has been made, signed, and certified in accordance with this section.

(f) Changing authorized account representative and alternate authorized account representative; changes in entities that own compliance instruments.

(1) The authorized account representative for an account may be changed at any time upon receipt by the accounts administrator of a superseding complete application for an account under section 95830(c) (1). Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous authorized account representative, or the previous alternate authorized account representative prior to the time and date when the accounts administrator receives the superseding application for an account shall be binding on the new authorized account representative and the entities that own the compliance instruments in the account.

(2) The alternate authorized account representative for an account may be changed at any time upon receipt by the accounts administrator of a superseding complete application for an account under section 95830(c) (1). Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous authorized account representative, or the previous alternate authorized account representative, prior to the time and date when the accounts

administrator receives the superseding application for an account shall be binding on the new alternate authorized account representative and the entities that own the compliance instruments in the account.

(3) In the event that a new entity owning compliance instruments in the account is not included in the list of entities in the application for an account, the new entity shall be subject to and bound by the application for an account, the representations, actions, inactions, and submissions of the authorized account representative and any alternate authorized account representative, and the decisions, orders, actions, and inactions of the accounts administrator, as if the new entity were included in such list.

(4) Within 1 day following any change in the entities that own compliance instruments in the account, including the addition or deletion of entities, the authorized account representative or any alternate authorized account representative shall submit a revision to the application for an account amending the list of entities that own the compliance instruments in the account to include the change.

(g) Objections concerning authorized account representative.

(1) Once a complete application for an account under section 95830(c)(1) has been submitted and received, the accounts administrator will rely on the application unless and until a superseding complete application for an account under section 95830(c)(1) is received by the accounts administrator.

(2) Except as provided in sections 95832(f)(1), no objection or other communication submitted to the accounts administrator concerning the authorization, or any representation, action, inaction, or submission of the authorized account representative or any alternate authorized account representative for an account shall affect any representation, action, inaction, or submission of the authorized account

representative or any alternate authorized account representative or the finality of any decision or order by the accounts administrator under title 17, article 5, sections 95800 et seq.

(3) The accounts administrator will not adjudicate any private legal dispute concerning the authorization or any representation, action, inaction, or submission of the authorized account representative or any alternate authorized account representative for an account, including private legal disputes concerning the proceeds of compliance instrument transfers.

(h) Delegation by authorized account representative and alternate authorized account representative.

(1) An authorized account representative may delegate, to one or more natural persons, his or her authority to make an electronic submission to the accounts administrator provided for under section 95832(c) (2).

(2) An alternate authorized account representative may delegate, to one or more natural persons, his or her authority to make an electronic submission to the accounts administrator provided for under section 95832(c) (2).

(3) In order to delegate authority to make an electronic submission to the accounts administrator in accordance with section 95832(h)(1) and (2) the authorized account representative or alternate authorized account representative, as appropriate, must submit to the accounts administrator a notice of delegation, that includes the following elements:

(A) The name, address, E-mail address, telephone number, and facsimile transmission number of such authorized account representative or alternate authorized account representative;

(B) The name, address, email address, telephone number and facsimile transmission number of each such natural person, herein referred to as "electronic submission agent";

(C) For each such natural person, a list of the type of electronic submissions for which authority is delegated to him or her; and

(D) The following certification statements by such authorized account representative or alternate authorized account representative:

(i) "I agree that any electronic submission to the accounts administrator that is by a natural person identified in this notice of delegation and of a type listed for such electronic submission agent in this notice of delegation and that is made when I am a authorized account representative or alternate authorized account representative, as appropriate, and before this notice of delegation is superseded by another notice of delegation under section 95832(h)(3) shall be deemed to be an electronic submission by me."

(ii) "Until this notice of delegation is superseded by another notice of delegation under section 95832(h)(3), I agree to maintain an email account and to notify the accounts administrator immediately of any change in my email address unless all delegation authority by me is terminated."

(4) A notice of delegation submitted under section 95832(h)(3) shall be effective, with regard to the authorized account representative or alternate authorized account representative identified in such notice, upon receipt of such notice by the accounts administrator and until receipt by the accounts administrator of a superseding notice of delegation by such authorized account representative or alternate authorized account representative as appropriate. The superseding

notice of delegation may replace any previously identified electronic submission agent, add a new electronic submission agent, or eliminate entirely any delegation of authority.

(5) Any electronic submission covered by the certification in section 95832(h)(3)(D) and made in accordance with a notice of delegation effective under section 95832(h)(3) shall be deemed to be an electronic submission by the authorized account representative or alternate authorized account representative submitting such notice of delegation.

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code.
Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

Subarticle 6: California Greenhouse Gas Allowance Budgets

§ 95840. Compliance Periods.

Duration of Compliance Periods is as follows:

(a) The first compliance period starts on January 1, 2012, and ends on December 31, 2014.

(b) The second compliance period starts on January 1, 2015, and ends on December 31, 2017.

(c) The third compliance period starts on January 1, 2018, and ends on December 31, 2020.

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code.
Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

§ 95841. Annual Allowance Budgets for Calendar Years 2012-2020.

The California GHG Allowance Budgets are set as described in Table 6-1.

Table 6-1: California GHG Allowances Budgets

	Budget Year	Annual Allowance Budget (Millions of CA GHG Allowances)
First Compliance Period	2012	165.8
	2013	162.8
	2014	159.7
Second Compliance Period	2015	394.5
	2016	382.4
	2017	370.4
Third Compliance Period	2018	358.3
	2019	346.3
	2020	334.2

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code.
Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

Subarticle 7: Compliance Requirements for Covered Entities

§ 95850. General Requirements.

(a) Reporting Requirements. Each covered entity identified in section 95811 is subject to the Mandatory Reporting Regulation.

(b) Record Retention Requirements. Each covered entity must retain all of the following records for at least 10 consecutive years and must provide such records within 20 calendar days of receiving a written request from the Executive Officer:

(1) Copies of all data and reports submitted to the Executive Officer under this article and section 95105 of the Mandatory Reporting Regulation, Document Retention and Recordkeeping Requirements;

(2) Records used to calculate a compliance obligation as specified in section 95853; and

(3) Verification statement as required pursuant to section 95103(f) of the Mandatory Reporting Regulation, Greenhouse Gas Reporting Requirements.

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code.
Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

§ 95851. Phase-in of Compliance Obligation for Covered Entities.

(a) Operators of facilities and first deliverers of electricity specified in section 95811(a) and (b) and suppliers of CO_2 specified in section 95811(g) that meet or exceed the annual emissions threshold in section 95812(b) have compliance obligations beginning with the first compliance period.

(b) The suppliers of natural gas, suppliers of RBOB and distillate fuel oils, and suppliers of liquefied petroleum gas specified in section 95811(c), (d), and (e) and that meet or exceed the annual threshold in section 95812(d) will have a compliance obligation beginning with the second compliance period.

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code.
Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

§ 95852. Emission Categories Used to Calculate Compliance Obligations.

(a) Operators of Facilities. An operator of a facility covered under section 95811(a) and 95812(b)(1) has a compliance obligation for every metric ton

of CO_2e for which a positive verification statement or a qualified positive verification statement is issued, both for process emissions and stationary combustion emissions.

(b) First Deliverers of Electricity. A deliverer of electricity covered under sections 95811(b) and 95812(b)(2) has a compliance obligation for every metric ton of CO_2e emissions for which a positive verification statement or qualified positive verification statement is issued, and every metric ton of CO_2e of stationary combustion emissions, or emissions associated with electricity imported into California from a source in a jurisdiction where a GHG emissions trading system has not been approved for linkage by the Board pursuant to subarticle 12.

(c) Suppliers of Natural Gas. A supplier of natural gas covered under section 95811(c) and 95812(d) has a compliance obligation for every metric ton CO_2e of GHG emissions that would result from full combustion or oxidation of all fuel delivered to end users in California, less the fuel that is delivered to covered entities.

(d) Suppliers of RBOB and Distillate Fuel Oils. A supplier of petroleum products covered under section 95811(d) or 95812(d) has a compliance obligation for every metric ton CO_2e of GHG emissions that would result from full combustion or oxidation of the quantities of the following fuels that are imported and/or delivered to California:

(1) RBOB;

(2) Distillate Fuel Oil No. 1;

(3) Distillate Fuel Oil No. 2.

(e) Suppliers of Natural Gas Liquids.

(1) A producer of liquefied petroleum gas covered under section 95811(e) and 95812(d) has a compliance obligation for every metric ton CO_2e of GHG emissions that would result from full combustion or oxidation of

all fuel sold, distributed, or otherwise transferred for consumption in California; and

(2) An importer consignee of liquefied petroleum gas covered under section 95811(e) has a compliance obligation for every metric ton CO_2e of GHG emissions that would result from full combustion or oxidation of all fuel imported into California.

(f) Suppliers of Blended Fuels. An entity that supplies any of the fuels covered under section 95811(f) and 95812(d) as blended fuels has an aggregated compliance obligation based on the separate constituents of the blend.

(g) Suppliers of Carbon Dioxide. An entity that supplies carbon dioxide covered under section 95811(g) has an aggregated compliance obligation based on the sum of imported and exported quantities of CO_2.

(h) The compliance obligation is calculated based on the sum of (i) emissions of CO_2, CH_4, and N_2O resulted from combustion of fossil fuel; (ii) emissions of CH_4 and N_2O resulted from combustion of all biomass-based fuel; (iii) emissions of CO_2 resulted from combustion of unverifiable biomass-derived fuels, as specified in section 95852.2; (iv) emissions of CO_2 resulted from combustion of biomass-derived fuels not listed in section 95852.2; and (v) all process and vented emissions of CO_2, CH_4, and N_2O as specified in the Mandatory Reporting Rule except for those listed in section 95852.2(a)(6) below.

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code.
Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

§ 95852.1. Compliance Obligations for Biomass-Derived Fuels.

An entity that has emissions from biomass-derived fuels is required to report and verify its emissions pursuant to Mandatory Reporting Regulation section 95130

and has a compliance obligation for every metric ton of CO_2e emissions from biomass-derived fuels that would result from full combustion or oxidation of all fuel for emissions identified below:

(a) Emissions from source categories that are not listed under section 95852.2 below; or

(b) Emissions, from source categories listed in 95852.2, without information and documentation necessary to establish the validity of biomass-derived fuels which are considered unverifiable pursuant to MRR section 95131(i).

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code.
Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

§ 95852.2. Emissions without a Compliance Obligation.

Emissions from the following source categories as identified in sections 95100 through 95199 of the Mandatory Reporting Regulation count toward applicable reporting thresholds but do not count toward a covered entity's compliance obligation set forth in this regulation. These source categories include:

(a) Combustion emissions from biomass-derived fuels (except biogas from digesters) from the following sources:

(1) Solid waste materials;

(2) Waste pallets, crates, dunnage, manufacturing and construction wood wastes, tree trimmings, mill residues, and range land maintenance residues;

(3) All agricultural crops or waste; or

(4) Wood and wood wastes identified to follow all of the following practices;

(A) Harvested pursuant to approved timber management plan prepared in accordance with the Z'berg-Nejedly Forest Practice Act of 1973 or other locally or nationally approved plan;

(B) Harvested for the purpose of forest fire fuel reduction or forest stand improvement; and

(C) Do not transport or cause the transport of species known to harbor insect or disease nests outside zones of infestation or quarantine zones identified by the department of Food and Agriculture of the Department of Forestry and Fire Protection, unless approved by these agencies.

(b) Biodiesel:

(1) Agri-biodiesel derived solely from virgin oils, including esters derived from virgin vegetable oils from corn, soybeans, sunflower seeds, cottonseeds, canola, cramble, rapeseeds, safflowers, flaxseeds, rice bran, mustard seeds, and camelina, and from animal fats.

(2) Biodiesel is defined as monoalkyl esters of long chain fatty acids derived from following plant or animal matter that meets the requirements of the American Society of Testing Materials (ASTM) D6751:

(A) Waste oils;

(B) Tallow; or

(C) Virgin oils.

(c) Fuel ethanol:

(1) Cellulosic biofuel produced from lignocellulosic or hemicellulosic material that has a proof of at least 150 without regard to denaturants;

(2) Corn starch; or

(3) Sugar cane.

(d) Municipal Solid Waste (biogenic fraction only as determined by methodology specified in ASTM D6866):

(1) Direct combustion; or

(2) Conversion to a clean burning fuel:

(A) Technology does not use air or oxygen in the conversion process except to maintain temperature control;

(B) Technology produces no discharges or emissions of air contaminates, including greenhouse gases;

(C) No discharges to surface or groundwater;

(D) Produces no hazardous wastes as identified in ASTM D6866;

(E) Removes recyclable and green waste compostable materials, and recycles or compost these materials; or

(F) Any wastes that come to a facility come from an agency that diverts al least 30 percent of all solid waste collected through solid waste reduction, recycling, and composting.

(e) Biomethane from the following sources:

(1) All animal and other organic waste; or

(2) Landfill gas and wastewater.

(f) Fugitive and process emissions from:

(1) CO_2 emissions from geothermal generating units;

(2) CO_2 and CH_4 emissions from geothermal facilities;

(3) CO_2 emissions from hydrogen fuel cells;

(4) At petroleum refineries: asphalt blowing operations, equipment leaks, storage tanks, and loading operations; or

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

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code.
Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

§ 95852.3. Effect of Status of Verification Statement on Calculation of Compliance Obligations.

(a) In the case of a positive or qualified positive verification statement, the compliance obligation equals the reported and verified emissions, as outlined in section 95131 of the Mandatory Reporting Requirements.

(b) In the case of an adverse verification statement, for every metric ton of CO_2e of GHG emissions, as determined by ARB, the compliance obligation equals the ARB-assigned emissions as outlined in section 95103 of the Mandatory Reporting Regulation.

(c) In the case that an entity does not submit an emissions data report or complete verification, then the Executive Officer will determine its compliance obligation as set forth in section 95103 of the Mandatory Reporting Regulation.

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code.
Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

§ 95853. Calculation of Covered Entity's Triennial Compliance Obligation.

(a) A covered entity that exceeds the threshold in section 95812 in any of the three data years preceding the start of a compliance period is a covered entity for the entire compliance period. The covered entity's triennial compliance obligation in this situation is calculated as the total verified emissions from all three data years of the compliance period.

(b) A covered entity that initially exceeds the threshold in section 95812 in the first year of a compliance period is a covered entity for the entire compliance period. The covered entity's triennial compliance obligation in this situation is calculated as the total verified emissions from all three data years of the compliance period.

(c) A covered entity that initially exceeds the threshold in section 95812 in the second year of a compliance period is a covered entity for the second an dthird years of the compliance period. The covered entity's triennial compliance obligation in this situation is calculated as the total verified emissions from the second and third data years of the compliance period.

(d) A covered entity that initially exceeds the threshold in section 95812 in the third year of a compliance period has a compliance obligation for its verified emissions for that year, but the entity's triennial surrender obligation for the current compliance period is not due the following year. Instead the entity's verified emissions for the third year of the compliance period will be added to the entity's triennial obligation for the subsequent compliance period.

(e) For a new entrant that is eligible to receive free allowances pursuant to subarticles 8 and 9, the first year for this entity to receive free allowances is the year following the first year in which its emissions exceed the threshold in section 95812. The number of free allowances for this new entrant to receive in that year is twice the number calculated pursuant to section 95891.

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code.
Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

§ 95854. Quantitative Usage Limit on Designated Compliance Instruments—Offset Credits.

The number of offset credits that each covered entity may surrender to meet its annual or triennial compliance obligation must conform to the following limit:

O/S must be less than L

Where:

O = Total number of compliance instruments that are designated as subject to this quantitative usage limit pursuant to subarticle 4, section 95821(b), (c), and (d).

Sector-based offset credits as defined in section 95821 cannot represent more than 25% of O in the first and second compliance periods and 50% of O in all other periods.

S = Covered entity's annual or triennial compliance obligation.

L = Quantitative offset credit usage limit, set at 0.08.

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code.
Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

§ 95855. Annual Compliance Obligation.

(a) An entity has an annual compliance obligation for any year when the entity is a covered entity except for the condition specified in section 95853(d); and

(b) The annual compliance obligation for a covered entity equals thirty percent of positive or qualified positive GHG emissions reported from the previous data year.

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code.
Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

§ 95856. Timely Surrender of Compliance Instruments by a Covered Entity.

(a) A covered entity must surrender one compliance instrument for each metric ton of CO_2e of GHG emissions for the annual and triennial compliance obligations calculated pursuant to this subarticle.

(b) Compliance Instruments Valid for Surrender.

(1) A California compliance instrument or an allowance approved pursuant to subarticles 4, 12, or 14 may be used to satisfy a compliance obligation.

(2) To fulfill any compliance obligation, a compliance instrument must be issued from an allowance budget year within or before the year during which the compliance obligation is calculated, unless:

(A) the allowance was purchased from the Allowance Price Containment Reserve pursuant to section 95913; or

(B) the allowance is used to satisfy an excess emissions obligation.

(c) A covered entity must transfer from its holding account to its compliance account a sufficient number of compliance instruments to meet the compliance obligation set forth in sections 95853 and 95855.

(d) Deadline for Annual Surrender. For any year in which a covered entity has an annual compliance obligation pursuant to section 95855, it must fulfill that obligation

(1) By May 15 of the calendar year following the year for which the obligation is calculated if the entity reports by April 1 pursuant to section 95103 of MRR;

(2) By July 15 of the calendar year following the year for which the obligation is calculated if the entity reports by June 1 pursuant to section 95103 of MRR.

(e) Data Review and Determination of Triennial Obligation

(1) When a positive or qualified positive verification statement for the third year of the compliance period is received by ARB, the Executive Officer will review the accuracy of the verification statement and determine the covered entity's triennial obligation.

(2) If a positive or qualified positive verification statement for the third year of the compliance period is not received by ARB on time as set forth in

MRR, ARB will assign emissions according to the requirements set forth in section 95153 of the Mandatory Reporting Regulation.

(3) When the data review and reconciliation process, as stated in section 95104 of the Mandatory Reporting Regulation, for a covered entity has concluded, the Executive Officer shall issue a final determination of the covered entity's triennial compliance obligation.

(f) Triennial Surrender.

(1) The covered entity must transfer sufficient valid compliance instruments to its compliance account to fulfill its triennial surrender obligation by November 1 of the calendar year following the third year of the compliance period.

(2) The total number of allowances and offset credits submitted to fulfill the combined Annual and Triennial Surrender obligations is subject to the quantitative use limit on offset credits pursuant to section 95854.

(3) The Triennial Surrender obligation shall equal the Triennial Compliance Obligation calculated pursuant to section 95853 less allowances and offset credits.

(g) When the Executive Officer has determined the covered entity has met its surrender obligations, the Executive officer shall:

(1) Retire the compliance instruments surrendered; and

(2) Inform programs to which California is linked or recognizes, pursuant to subarticles 12 and 14, of the retirements, including the serial numbers of the compliance instruments retired.

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code.
Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

§ 95857. Untimely Surrender of Compliance Instruments by a Covered Entity.

(a) Applicability.

(1) A covered entity or opt-in covered entity that does not meet the compliance deadline for annual or triennial compliance pursuant to 95856 is subject to the compliance obligation for excess emissions as described in this section; and

(2) The compliance obligation for untimely surrender ("excess emissions") will not apply to a covered entity or opt-in covered entity which is determined to have transferred insufficient instruments to meet the compliance obligations of 95856 solely because of the reversal of an offset credit by the Executive Officer pursuant to section 95983 until 30 days after notice of reversal.

(b) Excess Emissions.

(1) The quantity of excess emissions is the difference between the compliance obligation calculated pursuant to this subarticle and any compliance instruments timely surrendered by the covered entity;

(2) The covered entity's compliance obligation for untimely surrender is calculated as four times the entity's excess emissions; and

(3) A covered entity's compliance obligation for untimely surrender may only be fulfilled with CA GHG allowances or allowances issued pursuant to subarticle 12.

(c) Recovery of the Untimely Surrender Obligation.

(1) The obligation to surrender allowances for excess emissions is immediately due;

(2) Immediately upon determining that a covered entity has excess emissions, the Executive Officer shall prevent any transfers of compliance instruments from the holding account controlled by the covered entity;

(3) The Executive Officer shall transfer any remaining allowances from the Holding Account controlled by the covered entity with excess

emissions to its compliance account until the retirement obligations of this section are met;

(4) If the Executive Officer is unable to retrieve sufficient allowances using the above process, the Executive Officer shall provide the deficient covered entity 30 days to secure the allowances needed to cover its untimely surrender obligation;

(5) If the covered entity fails to transfer allowances equal to the untimely surrender obligation pursuant to this section to its compliance account within the period specified in 95857(c)(4), the Executive Officer will:

(A) Identify holding accounts controlled by affiliates of the deficient covered entity to which the covered entity has transferred compliance instruments during the compliance period for which a compliance obligation remains unfilled; and

(B) The Executive Officer will prevent transfers from the holding accounts identified in (A) above, and retrieve allowances from those accounts to meet the untimely surrender obligation pursuant to this section.

(6) Additionally, if the covered entity or opt-in covered entity does not surrender sufficient allowances equal to its untimely surrender obligation pursuant to this section by the end of the 30-day period, the Executive Officer may pursue enforcement activities pursuant to subarticle 15.

(d) When the covered entity or opt-in covered entity meets its obligations pursuant to subsection (c) above, the Executive Officer shall:

(1) Remove the restrictions on transfers from the holding accounts controlled by the covered entity and affiliated entities;

(2) Transfer the allowances used to fulfill the untimely surrender obligation in the following manner:

(A) Three fourths to the highest-priced tier of the Allowance Price Containment Reserve Account; and

(B) One fourth to the Retirement Account.

(3) Inform programs to which California is linked or recognizes, pursuant to subarticles 12 and 14, of the retirements, including the serial numbers of the compliance instruments retired.

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code.
Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

Subarticle 8: Disposition of Allowances

§ 95870. Disposition of Allowances.

(a) Allowance Price Containment Reserve. On December 15, 2011, the Executive Officer shall transfer allowances to the Allowance Price Containment Reserve, as follows:

(1) One percent of the allowances from budget years 2012-2014,

(2) Four percent of the allowances from budget years 2015-2017, and

(3) Seven percent of the allowances from budget years 2018-2020.

(b) Advance Auction. On December 15, 2011, the Executive Officer shall transfer two percent of the allowances from budget years 2015-2020 to the Auction Holding Account.

(1) These allowances shall be auctioned pursuant to section 95910.

(2) The proceeds from the sale of these allowances will be deposited into the Air Pollution Control Fund and will be available upon appropriation by the Legislature for the purposes designated in California Health and Safety Code sections 38500 et seq.

(c) Allocation to Public Utilities.

(1) Electrical Distribution Utilities. The Executive Officer will place an annual individual allocation in the holding account of each eligible

distribution utility on or before January 15 of each calendar year from 2012-2020 pursuant to section 95892. Allowances available for allocation to electrical distribution utilities shall be 89 million multiplied by the cap adjustment factor in Table 9.2 for each budget year 2012-2020.

(2) Reserved for Natural Gas Distribution Utilities.

(d) Allocation to Industrial Covered Entities. Allowances allocated for the purposes of industry assistance shall be transferred to holding accounts for industrial sectors listed in Table 8-1.

(1) The Executive Officer will place an annual individual allocation in the holding account of each eligible covered entity on or before January 15 of each calendar year 2012-2020.

(2) Allocation to eligible covered entities shall be conducted using the assistance factors specified for each listed industrial sector found in Table 8-1 and the methodology set forth in section 95891.

(3) The total amount of allowances allocated for the purposes of industry assistance shall not exceed the available amount of allowances after accounting for allocations made pursuant to section 95870(a) through (c). If the amount calculated under the methodology set forth in section 95891 exceeds the amount of allowances available, the number of allowances available will be prorated equally across all eligible covered entities. The proration will be calculated using the share of allowances available after accounting for allocations made pursuant to sections 95870(a) through (c) compared to total allowances that would be distributed according to the methodology set forth in section 95891.

Table 8-1: Industry Assistance

Leakage Risk	ARB Classification	NAICS	Industry Assistance Factor (AF) by Budget Year		
			2012-2014	2015-2017	2018-2020
High	Oil and gas extraction	211111	100%	100%	100%
	Natural gas liquid extraction	211112	100%	100%	100%
	Soda ash mining and manufacturing	212391	100%	100%	100%
	Reconstituted Wood Product Manufacturing	321219	100%	100%	100%
	Paper manufacturing	322121	100%	100%	100%
	Paperboard manufacturing	322130	100%	100%	100%
	All Other Basic Inorganic Chemical Manufacturing	325188	100%	100%	100%
	Flat glass manufacturing	327211	100%	100%	100%
	Glass container manufacturing	327213	100%	100%	100%
	Cement manufacturing	327310	100%	100%	100%
	Lime manufacturing	327410	100%	100%	100%
	Iron and steel mill	331111	100%	100%	100%
Medium	Food manufacturing	311	100%	75%	50%
	Cut and sew apparel mfg	3152	100%	75%	50%
	Breweries	312120	100%	75%	50%
	Sawmills	321113	100%	75%	50%
	Petroleum refining	324110	100%	75%	50%
	Pesticide and agricultural chemical manufacturing	325320	100%	75%	50%
	Polystyrene foam product mfg	326140	100%	75%	50%
	Gypsum product manufacturing	327420	100%	75%	50%
	Mineral wool manufacturing	327993	100%	75%	50%
	Rolled steel shape manufacturing	331221	100%	75%	50%
	Secondary smelting and alloying of aluminum	331314	100%	75%	50%
	Secondary smelting, refining, and alloying of nonferrous metal (except copper and aluminum)	331492	100%	75%	50%
	Iron foundries	331511	100%	75%	50%
	Turbine and turbine generator set units manufacturing	333611	100%	75%	50%
Low	Pharmaceutical and medicine mfg	325412	100%	50%	30%
	Aircraft manufacturing	336411	100%	50%	30%

(e) Reserved for Allocation to Voluntary Renewable Energy Allowance Set-Aside.

(f) Auction Proceeds for AB 32 Statutory Objectives. All remaining allowances not allocated for uses specified in sections 95870(a)-(e) will be designated for sale at auction. The proceeds from the sale of these allowances will be deposited into the Air Pollution Control Fund and will be available for appropriation by the Legislature for the purposes designated in California Health and Safety Code sections 38500 et seq.

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code.
Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

Subarticle 9: Direct Allocations of California GHG Allowances

§ 95890. General Provisions for Direct Allocations.

(a) Eligibility Requirements for Industrial Facilities. A covered entity or opt-in covered entity from the industrial sectors listed in Table 8-1 shall be eligible for direct allocations of California GHG allowances if it has complied with the requirements of the MRR and has obtained a positive or qualified positive verification statement for the prior year pursuant to the MRR.

(b) Eligibility Requirements for Electrical Distribution Utilities. An electrical distribution utility shall be eligible for direct allocation of California if it has complied with the requirements of the MRR and has obtained a positive or qualified positive verification statement on its sales number for the prior year pursuant to the MRR.

(c) Reserved for Natural Gas Distribution Utilities.

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code.
Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

§ 95891. Allocation for Industry Assistance.

(a) The Executive Officer shall determine the amount of allowances directly allocated to each eligible covered entity or opt-in covered entity using the product output-based benchmarking allocation calculation methodology specified in subsection (b) if the entity is from the sector listed in both Table 8-1 and Table 9-1. The Executive Officer shall determine the amount of allowances directly allocated to each eligible covered entity or opt-in covered entity using the thermal energy-based benchmarking allocation calculation methodology specified in subsection (c) if the entity is from the sector listed in Table 8-1 but not listed in Table 9-1.

(b) Product Output-Based Allocation Calculation Methodology. The Executive Officer shall calculate the amount of California GHG Allowances directly allocated under a product output-based methodology annually using the following formula:

$$A_t = \sum_{a=1}^{n} Output_{a,t} * B_a * AF_{I,t} * c_{I,t}$$

Where,

"A_t" is the amount of California GHG allowances directly allocated to the operator of an industrial facility for all activities with a product output-based allocation from budget year "t";

"t" is the budget year from which the direct allocation occurs;

"t-2" is the year two years prior to year "t";

"t-3" is the year three years prior to year "t";

"t-4" is the year four years prior to year "t";

"a" is each eligible activity as defined in Table 9-1;

"n" is the number of eligible activities at a facility;

"$Output_{a,t}$" is the annual arithmetic mean amount of manufactured product output from a specific activity at a given facility for the data years "t-2," "t-3," and "t-4," as reported to ARB under the MRR using the output metrics identified in Table 9-1. If three years of data are unavailable the Executive Officer may employ a shorter time period to calculate the annual average;

"B_a" is the emissions efficiency benchmark per unit of output assigned by the Executive Officer to each eligible activity defined in Table 9-1;

"$AF_{I,t}$" is the assistance factor for budget year "t" assigned to each listed industrial sector "I" as specified in Table 8-1; and

"$c_{I,t}$" is the adjustment factor for budget year "t" assigned to each listed industrial sector "I" to account for cap decline as specified in Table 9-2.

Table 9-1: Product Output for Establishing Emissions Efficiency Benchmarks

Sector	NAICS code	Activity	Product Output
Oil and gas extraction	211111	Crude oil extraction by thermal production technique Crude oil extraction by non-thermal production technique Natural gas extraction	Barrel of crude oil by thermal production Barrel of crude oil by non-thermal production Mscf of natural gas
Soda ash manufacturing	212391	Soda ash mining and manufacturing	Ton of soda ash
Paper manufacturing	322121	Paper manufacturing from purchased pulp	Ton of paper products
Paperboard manufacturing	322130	Paperboard manufacturing from purchased pulp	Ton of paperboard products
Petroleum refining	324110	Petroleum refining Petroleum refining	Barrel of petroleum products Energy intensity index
Flat glass manufacturing	327211	Flat glass manufacturing	Ton of flat glass pulled
Container glass manufacturing	327213	Container glass manufacturing	Ton of container glass pulled
Cement manufacturing	327310	Cement manufacturing	Ton of cement produced
Lime manufacturing	327410	Dolime manufacturing	Ton of dolime produced
Gypsum manufacturing	327420	Gypsum manufacturing	Ton of gypsum products
Mineral wool manufacturing	327993	Fiber glass manufacturing	Ton of fiber glass pulled
Steel mill using electric arc furnace	331111	Steel production using electric arc furnace	Ton of steel produced
Hot rolled steel manufacturing	331221	Hot rolled steel production from purchased steel	Ton of rolled steel produced

(c) Thermal Energy Based Allocation Calculation Methodology. The Executive Officer shall calculate the amount of California GHG Allowances directly allocated under the thermal energy based methodology annually using the following formula:

$$A_t = \left(Steam * B_{Steam} + TE * B_{Fuel}\right) * AF_{I,t} * c_{I,t}$$

Where,

"A_t" is the amount of California GHG allowances directly allocated to the operator of an industrial facility with a thermal energy-based allocation from budget year "t";

"t" is the budget year from which the direct allocation occurs;

"Steam" is the historical baseline annual arithmetic mean amount of steam consumed, measured in MMBtu, at the industrial facility for use in any industrial process, including heating or cooling applications.
This value shall include any steam used to generate electricity consumed on-site but shall exclude any steam used to generate electricity for sale or transfer to off-site end users;

"B_{Steam}" is the emissions efficiency benchmark per unit of steam, 0.06244 California GHG Allowances/MMBtu Steam;

"TE" is the historical baseline annual arithmetic mean amount of thermal energy produced from fuel combustion at a given facility, measured in MMBtus. This value shall include any energy used to generate electricity consumed on-site but shall exclude any energy used to generate electricity for sale or transfer to off-site end users. This value shall exclude energy to generate the steam accounted for in the "Steam" term;

"B_{Fuel}" is the emissions efficiency benchmark per unit of energy from fuel combustion, 0.05307 California GHG Allowances/MMBtu;

"$AF_{I,t}$" is the assistance factor for budget year "t" assigned to each listed industrial sector "I" as specified in Table 8-1; and

"$c_{I,t}$" is the adjustment factor for budget year "t" assigned to each listed industrial sector "I" to account for cap decline as specified in Table 9-2.

(1) Data Sources. In determining the average annual baseline values, the Executive Officer may employ all available data reported to ARB under the MRR for data years 2008-2010 and third-party verified data reported to the California Climate Action Registry for data years 2000-2007.

(2) Maximum Free Allocation. The Executive Officer shall ensure that the annual amount of California GHG Allowances directly allocated under the thermal energy based methodology to a covered entity for operations at a facility shall not exceed 110% of the maximum annual level of greenhouse gas emissions emitted during the historical data years of 2000-2010 from the facility in question.

(3) New Entrants. Covered entities of facilities that were not in operation prior to 2011 and are eligible for free allocation under the thermal energy-based methodology shall be assessed a baseline annual steam and/or thermal energy use values based on expected activity levels as determined by the Executive Officer.

(4) Facility Closures. Covered entities that are no longer subject to the cap-and-trade program due to reduced emissions or facility closure as determined subject to section 95812(b) shall no longer be eligible to receive allowances.

Table 9-2: Cap Adjustment Factors for Assistance to Industry

Cap Adjustment Factors for Assistance to Industry		
Budget Year	**Cap Adjustment Factor (c) for All Other Industries**	**Cap Adjustment Factor (c) for Cement Manufacturing (NAICS 327310)**
2012	1.000	1.000
2013	0.981	0.991
2014	0.963	0.981
2015	0.944	0.972
2016	0.925	0.963
2017	0.907	0.953
2018	0.888	0.944
2019	0.869	0.935
2020	0.851	0.925

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code.
Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

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

(a) Reserved for allocation to electrical distribution utilities.

(b) Transfer to Utility Accounts.

(1) Investor owned utilities. The Executive Officer will place allowances in the limited use holding account created for each electrical corporation.

(2) Publicly owned Electric Utilities. At least 90 days prior to receiving a direct allocation of allowances, publicly owned electric utilities will inform the Executive Officer of the share of their allowances that is to be placed:

(A) In the publicly owned electric utility's compliance account, or

(B) In the publicly owned electric utility's limited use holding account.

(c) Monetization Requirement. Each calendar year, an electrical distribution utility must offer for sale at auction all allowances in a limited use holding account that were issued:

(1) from budget years that correspond to the current calendar year; and

(2) from budget years prior to the current calendar year.

(d) Limitations on the Use of Auction Proceeds.

(1) Proceeds obtained from the monetization of allowances directly allocated to a publicly owned electric utility shall be subject to any limitations imposed by the governing body of the utility and to the additional limitations set forth in section 95892(d)(3) below.

(2) Proceeds obtained from the monetization of allowances directly allocated to investor owned utilities shall be subject to any limitations imposed by the California Public Utilities Commission and to the additional limitations set forth in section 95892(d)(3) below.

(3) Auction proceeds obtained by an electrical distribution utility shall be used exclusively for the benefit of retail ratepayers of each electrical distribution utility, consistent with the goals of AB 32, and may not be used for the benefit of entities or persons other than such ratepayers.

(A) Investor owned utilities shall ensure equal treatment of their own customers and customers of electricity service providers and community choice aggregators.

(B) To the extent that an electrical distribution utility uses auction proceeds to provide ratepayer rebates, it shall provide such rebates with regard to the fixed portion of ratepayers' bills or as a separate fixed credit or rebate.

(C) To the extent that an electrical distribution utility uses auction proceeds to provide ratepayer rebates, these rebates shall not be based solely on the quantity of electricity delivered to ratepayers from any period after January 1, 2012.

(e) Reporting on the Use of Auction Proceeds. No later than June 30, 2013, and each calendar year thereafter, each electrical distribution utility shall submit a report to the Executive Officer describing the disposition of any auction proceeds received in the prior calendar year. This report shall include:

(1) The monetary value of auction proceeds received by the electrical distribution utility.

(2) How the electrical distribution utility's disposition of such auction proceeds complies with the requirements of this section and the requirements of California Health and Safety Code sections 38500 et seq.

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code.
Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

§ 95893. Reserved for Allocation to Natural Gas Distribution Utilities for Protection of Natural Gas Ratepayers

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code.
Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

Subarticle 10: Auction and Sale of California Greenhouse Gas Allowances

§ 95910. Timing of Auction of California GHG Allowances.

(a) Timing of the Allowance Auctions.

(1) The first auction shall be conducted on February 14, 2012.

(2) Subsequent auctions shall be conducted on the twelfth business day of the first month of each calendar quarter.

(b) An allowance may be designated for auction prior to its vintage year.

(c) For each quarterly auction:

(1) Auction of Allowances from Current Budget Year. From the budget year that matches the current calendar year, one quarter of the allowances designated for auction pursuant to section 95870(f) will be offered.

(2) Auction of Allowances from Future Budget Years. From the budget year three years subsequent to the current calendar year, one quarter of the allowances designated for advance auction pursuant to section 95870(b) will be offered.

(3) Auctions of allowances from different budget years will be conducted separately.

(d) Auction of Consigned Allowances.

(1) An entity may consign allowances to the Executive Officer for sale at the quarterly auctions only from a limited use holding account.

(2) When the Executive Officer withdraws allowances or offset credits from suspended or revoked holding accounts pursuant to 95831(b)(1):

(A) Allowances shall be consigned to the next auction.

(B) If after review the Executive Officer determines the withdrawn offset credits are valid, the Executive Officer will retire them, withdraw a similar number of allowances from the Auction Holding Account, and consign those allowances to auction in place of the retired offset credits.

(3) Each consigning entity agrees to accept the auction settlement price for allowances sold at auction.

(4) Allowances consigned to auction at least 60 days prior to the regular quarterly auction will be offered for sale at that auction.

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code.

Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

§ 95911. Format for Auction of California GHG Allowances.

(a) Auction Format.

(1) The auction will consist of a single round of bidding.

(2) Bids will be sealed.

(3) Bid quantities must be submitted as multiples of 1,000 metric tons of CO_2e.

(4) Bid prices must be submitted in whole dollars and whole cents.

(b) Auction Reserve Price Schedule.

(1) Each auction will be conducted with an auction reserve price.

(2) No allowances will be awarded for bids lower than the auction reserve price.

(3) If an auction settlement price equals the reserve price:

(A) The auction operator will fulfill winning bids with allowances from consignment sources in the following order:

(i) allowances consigned to auction pursuant to section 95910(d)(2);

(ii) allowances consigned from limited use holding accounts pursuant to subarticle 5;

(iii) allowances directly allocated by ARB to auction pursuant to subarticle 8.

(B) When there are insufficient winning bids to exhaust the allowances from a consignment source in (A) above, the auction operator will sell an equal number of allowances from each consigning entity in that source.

(4) Allowances designated by ARB for an auction which remain unsold when the auction settlement price equals the auction reserve price

shall be transferred to the highest-priced tier in the Allowance Price Containment Reserve Account.

(5) Disposition of Consigned Allowances Remaining Unsold at Auction.

(A) Allowances consigned to auction from limited use holding accounts that remain unsold at auction will be returned to the respective source accounts.

(B) Allowances consigned to auction pursuant to section 95831(b)(1) that remain unsold at auction will be held in the Auction Holding Account until the next auction.

(6) Method for Setting the Auction Reserve Price.

(A) For auctions conducted in calendar year 2012 the Reserve Price shall be $10 per metric ton of CO_2e for vintage 2012 allowances, and $11.58 per metric ton of CO_2e for vintage 2015 allowances.

(B) For auctions conducted in calendar years after 2012 the Reserve Prices shall be the Auction Reserve Prices for the previous calendar year increased annually by 5 percent plus the rate of inflation as measured by the Consumer Price Index for All Urban Consumers.

(c) Auction Purchase Limit. For auctions conducted from January 1, 2012, through December 31, 2014, the share of allowances of any vintage year offered at any quarterly auction which may be purchased by one entity or a group of entities with a corporate association pursuant to 95914 shall be limited to less than:

(1) For covered entities and opt-in covered entities: ten percent of the allowances offered for auction.

(2) For investor owned electrical utilities receiving a direct allocation of allowances pursuant to 95892(b) and subject to the monetization requirement pursuant to 95892(c): the auction purchase limit in (A)

does not apply. This subsection (B) shall not be interpreted to exempt said investor owned electrical utilities from any other requirements of this article; and

(3) For all other auction participants: four percent of the allowances offered for auction.

(d) Determination of Winning Bidders and Settlement Price. The following process shall be used to determine winning bidders, amounts won, and a single auction settlement price:

(1) Each bid will consist of a price and the quantity of allowances, in multiples of 1,000 metric tons of CO_2e, desired at that price.

(2) Each bidder may submit multiple bids.

(3) Beginning with the highest bid price, bids will be considered in declining order by price, and the auction operator shall reject a bid:

(A) If acceptance of the bid would result in violation of the purchase limit pursuant to sections 95911(c), 95914, and 95915;

(B) If acceptance of the bid would result in violation of the holding limit pursuant to sections 95914 and 95920(b); or

(C) If acceptance of the bid would result in a total value of accepted bids for an auction participant greater than the value of the bid guarantee submitted by the auction participant pursuant to section 95912(i).

(4) Beginning with the highest bid price, bids will be considered in declining order by price and entities submitting bids at that price will be awarded allowances until either:

(A) The next lower bid price is less than the auction reserve price, in which case the current price becomes the auction settlement price; or

(B) The total quantity of allowances contained in the bids at the next lower bid price is greater than or equal to the number of

allowances yet to be awarded, in which instance, the next lower bid price becomes the auction settlement price and the procedure for resolution of tie bids in section 95911(d)(5) shall apply.

(5) Resolution of tie bids:

(A) If the quantity of allowances contained in the bids placed at the lowest bid is greater than the quantity of allowances available to be sold at that price, then the auction operator will assign a random number to each bundle of 1,000 metric tons of CO_2e contained in each of the bids at that price.

(B) Beginning with the lowest random number assigned and working in increasing order of the random numbers assigned, the auction operator shall sell allowances to the bidder assigned the random number until the remaining allowances are sold.

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code.
Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

§ 95912. Auction Administration and Registration.

(a) The Executive Officer may serve as auction administrator or designate an entity to serve as auction administrator.

(b) The Executive Officer may direct that the California allowances designated for auction be offered through an auction conducted jointly with other jurisdictions to which California links pursuant to subarticle 12, provided the joint auction conforms with this article.

(c) Auction Registration Requirements. An entity that intends to participate in the auction must complete an auction registration at least thirty days prior to the auction.

(1) The details of the auction will be provided in a public notice by the Executive Officer no later than 60 days prior to the auction.

(2) An entity will be required to provide information and documentation which must include:

(A) Information and documentation regarding the corporate identity, ownership, and capital structure of the applicant;

(B) the existence of any direct or indirect corporate associations pursuant to 95914;

(C) Declarations as to the beneficial holding of any compliance instrument that may be acquired through the auction which requires disclosure of bidding associations pursuant to 95915, or that already exists prior to the auction;

(D) The identification of any indictment or felony conviction of the bidder, or any member, director, principal, partner, or officer of the applicant or any associated or related entity;

(E) The identification of any previous or pending investigation with respect to any alleged violation of any rule, regulation, or law associated with any commodity market or exchange.

(F) The applicant's holding account number.

(d) Protection of Confidential Information.

(1) An entity approved for auction participation shall not publicly release confidential information related to its auction participation, including:

(A) Qualification status;

(B) Bidding strategy;

(C) Bid price or bid quantity information;

(D) Information on the financial security it provides to the auction administrator;

(E) Other information identified in the auction application by the auction administrator.

(2) If an entity participating in an auction has retained the services of an advisor regarding auction bidding strategy, the entity must ensure

against the advisor transferring information to other auction participants or coordinating the bidding strategy among participants.

(3) To the extent permitted by state law, the Executive Officer will treat the information contained in the auction application as confidential business information.

(4) Following the auction, the Executive Officer may release the following information:

(A) The names of the bidders;

(B) Auction settlement price; and

(C) Aggregated or distributional information on purchases with the names of the entities withheld.

(e) If the Executive Officer determines that a bidder has provided false or misleading information, or has withheld pertinent information in its application, or has violated any part of the auction rules, the bidder may be prohibited from participating in any future auctions. This prohibition shall be in addition to any other penalties, fines, and additional remedies available at law.

(f) An entity registering as an auction participant must also be registered as provided in sections 95811, 95813, or 95814, as applicable.

(g) An entity whose holding account has been revoked or is currently suspended pursuant to section 96011 cannot participate in an auction.

(h) All bids shall be submitted on a schedule and in a form and manner prescribed by the Executive Officer and will be considered binding offers for the purchase of allowances under the rules of the auction.

(i) Registrants must provide a bid guarantee to the auction administrator at least one week prior to the auction.

(1) The bid guarantee must be in one or a combination of the following forms:

(A) A bond issued by a financial institution with a United States banking license.

(B) Cash in the form of a wire transfer or certified funds, such as a bank check or cashier's check.

(C) An irrevocable letter of credit issued by a financial institution with a United States banking license.

(D) If California participates in a joint auction with one or more Canadian Provinces pursuant to 95912 (b) then bonds or irrevocable letters of credit issued by a financial institution with a Canadian banking license will be acceptable.

(2) The amount of the bid guarantee must be greater than or equal to the sum of the value of the bids submitted by the auction participant.

(j) At least 60 days prior to each auction the auction administrator shall publish on the following information:

(1) The date and time of the auction;

(2) application instructions for applying to participate in the auction;

(3) the form and manner for submitting bids;

(4) the procedures for conducting the auction;

(5) the administrative requirements for participation; and

(6) the number of CA GHG Allowances that will be available at each auction.

(k) To conduct the auction the auction administrator will:

(1) process registration bid guarantees;

(2) determine that bids and bid quantities conform with purchase limits set for the auction pursuant to 95911(c), the holding limit pursuant to 95920(b), and the amount of the bid guarantee provided by the registrant;

(3) determine the winning bids and auction price; and

(4) inform the Executive Officer of the auction results.

(l) Following the auction, the Executive Officer will:

(1) Certify whether the auction was operated pursuant to this article;

(2) After certification, direct the auction operator to:

(A) Collect payments from winning bidders;

(B) Declare forfeit and retain the bid guarantee mechanism submitted pursuant to 95912(i) for any bidder that fails to tender full payment when due for allowances awarded at auction, in an amount equal to any unpaid balance.

(C) Deposit auction proceeds from sales of ARB allowances sold at auction into the Air Pollution Control Fund.

(D) Distribute auction proceeds to entities that consigned allowances for auction pursuant to 95910(d).

(3) Upon determining that the payment for allowances has been deposited into the Air Pollution Control Fund or transferred to entities that consigned allowances, transfer the serial numbers of the allowances purchased into each winning bidder's Holding Account;

(4) Inform each approved external GHG emissions trading system and the associated tracking system of the serial numbers of allowances purchased at auction; and

(5) Publish the auction results at www.arb.ca.gov.

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code.
Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

§ 95913. Sale of Allowances from the Allowance Price Containment Reserve.

(a) The Executive Officer may administer sales from the Allowance Price Containment Reserve or contract with an entity to administer sales from the Allowance Price Containment Reserve.

(b) If California links to an external greenhouse gas emissions trading system (GHG ETS) then the linkage agreement will specify whether covered entities in the linked GHG ETS will be eligible to purchase from a jointly operated Allowance Price Containment Reserve, or whether each ETS will operate such Reserves separately.

(c) Timing, Eligible participants, and Limitations.

(1) Eligible participants.

(A) Only covered entities (including opt-in covered entities) registered as provided in sections 95811 or 95813 shall be eligible to purchase allowances from the Allowance Price Containment Reserve.

(B) Only covered entities (including opt-in covered entities) which hold no compliance instruments in their holding accounts or limited use holding accounts may purchase allowances from the Allowance Price Containment Reserve.

(2) The administrator of the Allowance Price Containment Reserve shall offer all of the allowances in the Allowance Price Containment Reserve Account at each reserve sale.

(3) Timing.

(A) The first reserve sale will be conducted on March 4, 2012.

(B) Subsequent sales shall be conducted three weeks after each quarterly allowance auction pursuant to 95910.

(C) The administrator shall provide all eligible participants with written notice of the number of allowances available for sale and the terms of the sale at least four weeks prior to the sale.

(4) Limitation. Allowances purchased from the Allowance Price Containment Reserve are subject to the Holding Limit established pursuant to section 95920.

(d) Reserve Tiers.

(1) Creation of Reserve Tiers. The Executive Officer shall divide allowances allocated to the Allowance Price Containment Reserve into three equal-sized tiers.

(2) Reserve Tier Prices. Sales of reserve allowances in calendar year 2012 shall be conducted at the following prices:

(A) Allowances from the first tier shall be offered for $40 per allowance;

(B) Allowances from the second tier shall be offered for $45 per allowance; and

(C) Allowances from the third tier shall be offered for $50 per allowance.

(3) Increase in Release Prices. In calendar years subsequent to 2012, allowances from each tier shall be offered at prices equal to the offer price for each tier from the previous calendar year increased by 5 percent plus the rate of inflation as measured by the Consumer Price Index for All Urban Consumers.

(e) Submissions of Bids to Purchase. At least two weeks prior to the scheduled sale, a covered entity shall submit to the reserve sale administrator:

(1) a schedule of bids containing the number of allowances the entity intends to purchase from each of the three reserve tiers, in multiples of 1,000 metric tons of CO_2e, up to the covered entity's holding limit; and

(2) a bid guarantee in an amount greater than or equal to the sum of the value of the bids submitted by the covered entity, in one or a combination of the following forms:

(A) A bond issued by a financial institution with a United States banking license.

(B) Cash in the form of a wire transfer or certified funds, such as a bank check or cashier's check.

(C) An irrevocable letter of credit issued by a financial institution with a United States banking license.

(D) If California participates in a joint Allowance Price Containment Reserve with one or more GHG ETS programs in the Canadian Provinces to which it links and covered entities from linked systems are eligible to purchase from the Reserve pursuant to 95913(b), then bonds or irrevocable letters of credit issued by a financial institution with a Canadian banking license will be acceptable.

(f) Purchase Determinations.

(1) The reserve sale administrator will conduct sales from each tier in succession, beginning with the lowest to the highest priced tier.

(2) For each tier the reserve sale administrator will only accept a bid

(A) If acceptance of the bid would not result in violation of the holding limit pursuant to 95920(b); or

(B) If acceptance of the bid would not result in a total value of accepted bids for a covered entity greater than the value of the bid guarantee submitted by the covered entity pursuant to section 95913(e)(2).

(3) If the sum of bids accepted by the reserve sale administrator for a tier is less than or equal to the number of allowances in the tier, the reserve sale administrator will determine the total amount to be distributed from each tier to each covered entity as equal to the number of allowances for which the entity submitted bids which were accepted by the reserve sale administrator.

(4) If the sum of bids accepted by the reserve sale administrator for a tier is greater than the number of allowances in the tier, the reserve sale administrator will determine the total amount to be distributed from each tier to each covered entity using the following procedure.

(A) The reserve sale administrator will calculate the share of the tier to be distributed to each bidding entity by dividing the quantity bid by that entity and accepted by the reserve sale administrator by the total quantity of bids which were accepted by the reserve sale administrator.

(B) The reserve sale administrator will calculate the number of allowances distributed to each bidding entity from the tier by multiplying the bidding entity's share calculated in (2)(A) above by the number of allowances in the tier, rounding the number down to the nearest whole number.

(5) Inform the Executive Officer of the calculated distributions as required.

(g) Resolution of Sales. Following each sale of allowances from the Allowance Price Containment Reserve, the Executive Officer shall:

(1) Certify that the reserve sale was conducted pursuant to this article;

(2) Upon certification of the sale results, authorize the reserve sale administrator to process payments from covered entities and deposit proceeds into the Air Pollution Control Fund;

(3) Upon determining that the payment for allowances has been deposited into the Air Pollution Control Fund, transfer the serial numbers of the allowances purchased from the Allowance Price Containment Reserve Account into each winning bidder's compliance account;

(4) Inform each approved external GHG emissions trading system and the associated tracking system of the serial numbers of allowances sold; and

(5) Publish the sale results at www.arb.ca.gov.

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code.
Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

§ 95914. Disclosure of Direct and Indirect Corporate Associations.

(a) Entities registered pursuant to 95830 must disclose direct and indirect corporate associations with other registered entities.

(1) An entity has a "direct corporate association" with another entity if either one of these entities:

(A) Holds more than twenty percent of any class of listed shares, the right to acquire such shares, or any option to purchase such shares of the other entity;

(B) Holds or can appoint more than twenty percent of common directors of the other entity;

(C) Holds more than twenty percent of the voting power of the other entity; or

(D) Controls more than twenty percent of the other entity's affairs through some other means.

(E) Holds compliance instruments in its own holding account in which the other entity has an ownership interest.

(2) An entity has an "indirect corporate association" with another entity if one of these entities:

(A) Has a direct corporate association with another party that has a direct corporate association with the other entity in question, or through a longer line of direct corporate associations; and

(B) The percentage ownership of the entity in the other entity, obtained by multiplying the percentages of ownership at each association in a line of direct corporate associations, must be more than twenty percent.

(b) If California links its ETS program with one or more GHG ETS programs in Canadian Provinces, then entities shall disclose corporate associations with entities registered into those ETS programs.

(c) If a registered entity has a direct or indirect corporate association with another registered entity, the information that must be disclosed includes:

(1) The name of the other entity;

(2) The share of the corporate association's purchase and holding limits assigned to the entity and associated entities pursuant to 95914(e) and 95914 (f);

(3) The type of corporate association (i.e., direct or indirect) and a brief description of the association, to include the following descriptors:

(A) Corporate parent;

(B) Subsidiary;

(C) Sister company;

(D) Partnership; and

(E) Other description.

(d) The entity must disclose the information to the Executive Officer:

(1) When registering pursuant to section 95830;

(2) At any time after registering when a disclosable association is created or exists;

(3) Within 30 days of a material change to the information disclosed on direct and indirect corporate associations; and

(4) At least 60 days prior to an auction when reporting a material change to the information disclosed, otherwise the entity may not participate in that auction.

(e) Application of the Corporate Association Disclosure to the Purchase Limit at Auction.

(1) The total number of compliance instruments which may be purchased in a single auction by a group of entities with a disclosed corporate association is limited pursuant to section 95911(c).

(2) Entities part of a corporate association may allocate shares of the purchase limit among themselves, if:

(A) The group of associated entities must inform the Executive Officer when submitting the auction application of an allocation of the purchase limit among the associated entities; this allocation results in each entity having a specified percentage share of the group's purchase limit.

(B) The sum of the shares allocated to each entity must be less than or equal to the purchase limit pursuant to section 95911(c).

(C) Each associated entity's allocated purchase share becomes the purchase limit for that entity.

(3) If entities with a corporate association do not allocate shares of the purchase limit among themselves, then the auction administrator will apply the purchase limit to the entities as follows:

(A) The administrator will order the entities' bids from highest to lowest bid price.

(B) Working from the highest to the lowest bid, the auction administrator will accept bids until the purchase limit for the associated entities is met.

(C) The auction operator will conduct this procedure before conducting the auction pursuant to section 95911.

(f) Application of the Corporate Association Disclosure to the Holding Limit.

(1) The total number of compliance instruments held by a group of entities with a disclosable corporate association must sum to less than the holding limit of the group of associated entities pursuant to section 95920(b).

(2) Entities part of a corporate association may allocate shares of the holding limit among themselves.

(A) The group of associated entities must inform the Executive Officer of the allocation or changes to the allocation pursuant to

section 95914(d); this allocation results in each entity having a specified percentage share of the group's holding limit.

(B) The sum of the shares allocated to each entity must be less than or equal to the holding limit.

(3) If entities with a corporate association do not allocate shares of the holding limit among themselves, the accounts administrator will not record any transaction which would result in the entities with a corporate association exceeding the holding limit.

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code.
Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

§ 95915. Identifying Disclosable Bidding Associations.

(a) Entities registering for the auction pursuant to section 95912 must disclose bidding associations with other entities also registered into the California cap-and-trade system or registered into one or more GHG ETS programs in Canadian Provinces to which California has linked.

(b) An entity has a disclosable "bidding association" with another entity if it:

(1) Has any form of agreement with another entity;

(2) Is partnered with the other entity for bidding purposes.

(3) Has agreed to provide assistance in any other way with the exception of investment or auction advisory services with the other entity.

(c) Disclosure requirements.

(1) Disclosable bidding associations must be reported in the auction registration application pursuant to section 95912(c).

(2) A complete description of the agreement or association, including parties to the agreement; their relationships, including which entity is purchasing and holding compliance instruments on behalf of a

recipient; and any terms or conditions. A copy of any documents that constitute or memorialize the agreement or association must be provided. If no such documents exist, the description of the agreement must explain how the agreement or association was created.

(d) Timing of Disclosure.

(1) The entity must disclose the information to the auction operator at least 30 days prior to an auction when reporting a material change to the information disclosed, otherwise the entity may not participate in that auction.

(2) Within 30 days of an auction or after filing an auction application, an entity may not communicate information on auction participation with any other entity that has not been disclosed as part of a bidding association, except as requested by the auction operator to remediate an auction application.

(3) Since an entity may not re-file the auction application after the deadline, an entity that makes a material change after the deadline may not participate in the auction.

(e) Application of the Bidding Association Disclosure to the Purchase Limit at Auction.

(1) The auction operator shall apply the purchase limit for an entity designated as the "recipient" in a bidding association to the bids submitted by that entity alone.

(2) Entities part of a bidding association may allocate shares of the purchase limit among themselves.

(A) The group of associated entities must inform the Executive Officer of an allocation of the purchase limit among the associated entities, such that the sum of the shares allocated to each entity sums to the purchase limit.

(B) Each associated entity's allocated purchase share becomes the purchase limit for that entity.

(3) If entities with a bidding association do not allocate shares of the purchase limit among themselves, the auction operator shall calculate the purchase limit for an entity or entities designated as a "purchaser" in a bidding association as the limit less the sum of bids submitted by the entity or entities in the bidding association designated as the "recipient," divided by the number of entities in the bidding association designated as "purchaser."

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code.
Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

Subarticle 11: Trading and Banking

§ 95920. Trading.

(a) General Prohibitions on Trading. The following practices involving any California compliance instruments are prohibited:

(1) a trade involving a counterparty whose identity is not disclosed to the Executive Officer;

(2) a trade involving, related to, or associated with:

(A) any manipulative or deceptive device in violation of this article;

(B) a corner or an attempt to corner the market for a regulated instrument;

(C) fraud, or an attempt to defraud any other entity;

(D) a false, misleading, or inaccurate report concerning information or conditions that affects or tends to affect the price of a regulated compliance instrument;

(E) an application, report, statement, or document required to be filed pursuant to this article, a statement which is false or misleading with respect to a material fact, or which omits any material fact required to be stated therein or necessary to make the contents therein not misleading; or

(F) any trick, scheme, or artifice to falsify or conceal a material fact, including use of any false statements or representations, written or oral, or documents made or provided to an entity on or through which transactions in regulated instruments occur, are settled, or are cleared.

(b) Holding Limit.

(1) The holding limit is the maximum number of California GHG allowances that may be held by an entity or group of associated entities registered pursuant to section 95830.

(2) The holding limit will apply to each entity with a holding account.

(3) Calculation The holding limit will be calculated and applied within each calendar year using the following formula:

Holding Limit = 0.1*Base + 0.025*(Annual Allowance Budget – Base)

In which:

"Base" equals 25 million metric tons of CO_2e.

"Annual Allowance Budget" is the number of allowances associated with the current budget year pursuant to subarticle 6.

(4) Limited Exemption from the Holding Limit.

(A) Allowances transferred by a covered entity or an opt-in covered entity to its compliance account during a single calendar year are exempt from the holding limit up to an amount equal to the

emissions reported in a positive or qualified positive verification statement covering the previous calendar year.

(B) The limited exemption for a calendar year is the sum of all previous annual transfer limits.

(C) On December 31 of the calendar year following the end of a compliance period, the limited exemption will be will be reduced by the sum of the entity's verified emissions over that compliance period.

(D) If a positive or qualified positive verification statement is not received by ARB on time as set forth in MRR, then ARB will calculate the exemption based on emissions assigned according to the requirements set forth in article 2, section 95130, title 17, California Code of Regulations, Requirements for Verification of Emissions Data Reports.

(5) If the Executive Officer determines that a reported transaction would result in an entity's holdings exceeding the holding limit, then the Executive Officer shall not approve the transaction pursuant to section 95921(a).

(6) The application of the holding limit will treat holdings of entities with a corporate association pursuant to section 95914 as being held by a single entity unless existing law or regulation prohibits coordinated market activity by the associated entities, including the transfer of instruments between accounts controlled by associated entities.

(7) The application of the holding limit will treat beneficial holdings by an agent as part of the holding of the owner.

(c) Restrictions on Registered Entities. The Executive Officer may impose the following restrictions on entities registered pursuant to section 95830 that violate any provision specified in this article:

(1) the number of compliance instruments held by a covered entity or opt-in covered entity may be restricted to an amount sufficient to cover its reported emissions;

(2) a covered entity or an opt-in covered entity may be subject to additional annual surrender requirements; and

(3) the registration of opt-in covered entities, voluntarily associated entities, and other registered participants under section 95830 may be suspended or revoked.

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code.
Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

§ 95921. Conduct of Trade.

(a) Each trade must meet the requirements set forth in this subarticle or the trade will not be accepted by the accounts administrator.

(b) Information Requirements. The following information must be provided for the accounts administrator to record the transaction:

(1) Account number and authorized account representative of seller;

(2) Account number and authorized account representative of purchaser;

(3) Serial number of compliance instrument;

(4) Date and time of transaction agreement;

(5) Settlement date and time, if not the same as date and time of transaction agreement;

(6) Price of the instrument in U.S. dollars. If California links to Canadian provinces pursuant to subarticle 12, the price of the instrument may be reported in Canadian dollars;

(7) Account number and authorized representative of an entity for whom the instrument is to be held in benefit;

(c) The seller and buyer must report each transaction within three calendar days of settlement of the transaction agreement.

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code.
Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

§ 95922. Banking, Expiration, and Voluntary Retirement.

(a) Allowances issued for a current or previous compliance period. A CA GHG allowance or an allowance approved pursuant to subarticle 12 may be held ("banked") by an entity registered pursuant to section 95930.

(b) Allowances issued for a future compliance period. A CA GHG Allowance or an allowance approved pursuant to subarticle 12 issued from an allowance budget year within a future compliance period may be held by an entity registered pursuant to section 95930.

(c) Expiration of Compliance Instruments. A California compliance instrument does not expire and is not removed from the tracking system until:

(1) it is surrendered by a covered entity or opt-in covered entity and retired by the Executive Officer;

(2) an entity voluntarily submits the instrument to the Executive Officer for retirement; or

(3) the instrument is retired by an approved external GHG emissions trading system to which the California system is linked as provided in subarticle 12.

(d) Voluntary Retirement of Compliance Instruments.

(1) An entity registered pursuant to section 95930 may voluntarily submit any compliance instrument for retirement.

(2) To voluntarily retire a compliance instrument, the registered entity submits a transaction report to the accounts administrator listing its

account number, the serial numbers of the instruments to be retired, and the ARB Retirement Account as the destination account.

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code.
Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

Subarticle 12: Linkage to External Greenhouse Gas Emissions Trading Systems

§ 95940. General Requirements.

A compliance instrument issued by an external greenhouse gas emissions trading system (GHG ETS) may be used to meet the requirements of this Article if the external GHG ETS and the compliance instrument have been approved pursuant to sections 95941 and 95942.

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code.
Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

§ 95941. Procedures for Approval of External GHG ETS.

The Board may approve a linkage with an external GHG ETS after public notice and opportunity for public comment in accordance with the Administrative Procedure Act (Government Code sections 11340 et seq.). Provisions set forth in this Article shall specify which compliance instruments issued by a linked GHG ETS may be used to meet a compliance obligation under this Article.

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code.
Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

§ 95942. Approval of Compliance Instruments from External GHG ETS.

(a) Once a linkage is approved, a compliance instrument issued by the approved external GHG ETS, as specified in section 95942, may be used to meet a compliance obligation under this Article.

(b) An allowance issued by an approved external GHG ETS and specified in section 95942 is not subject to the quantitative usage limit specified in section 95854.

(c) An offset credit or sector-based credit issued by an external GHG ETS is subject to the quantitative usage limit specified in section 95854, when used to meet a compliance obligation under this Article.

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code.
Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

§ 95943. Reserved for Linkage.

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code.
Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

Subarticle 13: Offset Credits Issued by ARB

§ 95970. General Requirements for Offset Credits Issued by ARB.

An Offset Project Operator or its Authorized Project Designee must meet the requirements for offset credits issued by ARB. An offset credit issued by ARB must:

(a) represent a GHG emission reduction or GHG removal enhancement that is real, additional, quantifiable, permanent, verifiable, and enforceable;

(b) when used for compliance under this Article be subject to the quantitative usage limit pursuant to section 95855;

(c) result from the use of a Compliance Offset Protocol adopted by the Board pursuant to section 95971;

(d) result from an offset project that meets the requirements specified in section 95973;

(e) result from an offset project that is listed pursuant to section 95975;

(f) follows the monitoring, reporting and record retention requirements pursuant to section 95976;

(g) be verified pursuant to sections 95977 through 95978;

(h) be issued pursuant to sections 95980 through 95981; and

(i) be registered pursuant to section 95982.

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code.
Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

§ 95971. Procedures for Approval of Compliance Offset Protocols.

The Board shall provide public notice of and opportunity for public comment prior to approving any Compliance Offset Protocols, including updates or modifications to existing Compliance Offset Protocols.

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code.
Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

§ 95972. Requirements for Compliance Offset Protocols.

(a) To be approved by the Board, a Compliance Offset Protocol must:

(1) accurately determine the extent to which GHG emission reductions or GHG removal enhancements are achieved by the offset project type;

(2) establish data collection and monitoring procedures relevant to the type of GHG emissions sources or GHG sinks for that offset project type;

(3) establish a project baseline that reflects a conservative estimate of business-as-usual performance or practices for the offset project type;

(4) account for activity-shifting leakage and market-shifting leakage for the offset project type;

(5) account for any uncertainty in quantification factors for the offset project type;

(6) ensure GHG emission reductions are permanent;

(7) include a mechanism to ensure permanence of GHG removal enhancements for sequestration offset project types; and

(8) establish the length of the crediting period pursuant to section 95972(b) for the relevant offset project type.

(b) Crediting Periods. The crediting period for a non-sequestration project must be no less than 7 years and no greater than 10 years. The crediting period for a sequestration project must be no less than 10 years and no greater than 30 years.

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code.
Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

§ 95973. Requirements for Offset Projects Using ARB Compliance Offset Protocols.

(a) General Requirements for Offset Projects. To qualify under the provisions set forth in this article, an offset project must:

(1) meet all of the requirements in a Compliance Offset Protocol approved by the Board pursuant to section 95971;

(2) meet the following additionality requirements as of the date of Offset Project Commencement:

(A) the GHG emission reduction or GHG removal enhancement activities, that result in GHG reductions or GHG removal enhancements, is not required by law, regulation, or any legally binding mandate applicable in the project's jurisdiction, or any GHG reduction or GHG removal enhancement activities that would otherwise occur in a conservative business-as-usual scenario;

(B) the Offset Project commencement date occurs after December 31, 2006; and

(C) the GHG reductions or GHG removal enhancements resulting from the offset project exceed the project baseline calculated by the Compliance Offset Protocol for that offset project type as set forth in the following:

(i) Compliance Offset Protocol Ozone Depleting Substances Projects, incorporated by reference [DATE];

(ii) Compliance Offset Protocol Livestock Projects, incorporated by reference [DATE];

(iii) Compliance Offset Protocol Urban Forest Projects, incorporated by reference [DATE]; and

(iv) Compliance Offset Protocol U.S. Forest Projects U.S., incorporated by reference [DATE].

(3) be located in the United States, Canada, or Mexico.

(b) Local, Regional, and National Environmental Impact Assessment Requirements. An Offset Project Operator or Authorized Project Designee must fulfill all local, regional and national requirements on environmental impact assessments that apply based on the offset project location.

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code.
Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

§ 95974. Authorized Project Designee.

(a) General Requirements for Designation of Authorized Project Designee. An Offset Project Operator may designate an entity as an Authorized Project Designee at the time of offset project listing. The Offset Project Operator must identify to ARB or an Offset Project Registry the rights and responsibilities they are assigning or delegating to an Authorized Project Designee at the time of offset project listing.

(1) The Offset Project Operator may assign ownership rights of offset credits to the following:

(A) Authorized Project Designee; or

(B) any other third party not otherwise prohibited by this article.

(2) The Offset Project Operator may delegate responsibility to the Authorized Project Designee for performing the requirements of sections 95975, 95976, and 95977.

(b) Modifications to Authorized Project Designee and Activities. An Offset Project Operator may modify or change an Authorized Project Designee, or any other third party authorized pursuant to section 95974(a)(1), for a listed offset project once within each calendar year after the offset project has been listed by ARB or an Offset Project Registry by submitting a request, in writing, to ARB or an Offset Project Registry.

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code.
Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

§ 95975. Listing of Offset Projects Using ARB Compliance Offset Protocols.

(a) General Requirements for Offset Project Operators or Authorized Project Designees Who Are Submitting an Offset Project for Listing. Before an offset project can be listed by ARB or an Offset Project Registry the Offset Project Operator, its Authorized Project Designee or another third party as provided in section 95974(a)(1) must be:

(1) registered with ARB pursuant to section 95830; and

(2) must not be subject to any Holding Account restrictions imposed pursuant to section 96011.

(3) An offset project must be listed by an Offset Project Registry approved pursuant to section 95986, if the offset project listing is not being originated by ARB.

(b) General Requirements for Offset Project Listing. For offset projects being listed by ARB or an Offset Project Registry in an initial or renewed crediting period, the Offset Project Operator or Authorized Project Designee must:

(1) Attest, in writing, to ARB as follows:
"I certify under penalty of perjury under the laws of California the GHG reductions or GHG removal enhancements for [project] from [date] to [date] will be measured in accordance with the [appropriate ARB Compliance Offset Protocol] and all information required to be submitted to ARB is true, accurate, and complete";

(2) Attest, in writing, to ARB as follows:
"I understand I am voluntarily participating in the California Greenhouse Gas Cap-and-Trade Program under title 17, article 5, and by doing so, I am now subject to all regulatory requirements and enforcement mechanisms of this program"; and

(3) provide all documentation required pursuant to section 95975(c) to ARB or an Offset Project Registry.

(4) The attestations in section 95975(b)(1) and 95975(b)(2) may be provided to an Offset Project Registry with the listing information but must be provided to ARB when the requirements in section 95981(d)(1) apply.

(c) Offset Project Listing Information Requirements. Before an offset project is publicly listed for an initial or renewed crediting period the Offset Project Operator or Authorized Project Designee must provide the listing information in a Compliance Offset Protocol for that offset project type as set forth in:

(1) Compliance Offset Protocol Ozone Depleting Substances Projects, [DATE];

(2) Compliance Offset Protocol Livestock Projects, [DATE];

(3) Compliance Offset Protocol Urban Forest Projects, [DATE]; and

(4) Compliance Offset Protocol U.S. Forest Projects [DATE].

(d) Notice of Completeness for Offset Project Listing Information. The Offset Project Operator or Authorized Project Designee will be notified after review by ARB or the Offset Project Registry, if the information submitted pursuant to section 95975(c) is complete and may be listed. If it is determined that the information submitted pursuant to section 95975(c) is incomplete, the Offset Project Operator or Authorized Project Designee will be notified within 30 calendar days by ARB or an Offset Project Registry.

(e) Timing for Offset Project Listing in an Initial Crediting Period. The Offset Project Operator or Authorized Project Designee must submit the information in section 95975(c) to ARB or an Offset Project Registry no later than the date at which the Offset Project Operator or Authorized Project Designee submits its required Offset Project Data Report to ARB or an Offset Project Registry pursuant to section 95976.

(f) Listing Status of Offset Projects in an Initial Crediting Period. After the Offset Project Operator or Authorized Project Designee submits the offset project for listing in an initial crediting period and the required documentation pursuant to section 95975(c), and ARB or the Offset Project Registry has reviewed the offset project against the additionality requirements in section 95973(a)(2), the offset project listing status will be "Proposed Project." If the offset project is not accepted for listing by an Offset Project Registry, the Offset Project Operator or Authorized Project Designee may request ARB to make a final determination if the project meets the requirements in section 95975 to be listed for an initial crediting period by the Offset Project Registry. In making this determination, ARB may consult with the Offset Project Registry before making the final determination.

(g) Timing for Offset Project Listing in a Renewed Crediting Period. The Offset Project Operator or Authorized Project Designee must submit the information in section 95975(c) for a renewed crediting period to ARB or an Offset Project Registry no earlier than 18 months and no later than 9 months from conclusion of the initial crediting period or a previous renewed crediting period.

(h) Listing Status of Offset Projects in a Renewed Crediting Period. After the Offset Project Operator or Authorized Project Designee submits the offset project for listing in a renewed crediting period and the required documentation pursuant to section 95975(c), and ARB or the Offset Project Registry has reviewed the offset project against the additionality requirements in section 95973(a)(2)(A) and (2)(C) as of the date of the commencement of the renewed crediting period, the offset project listing status will be "Proposed Renewal." If the offset project is not accepted for listing by an Offset Project Registry, the Offset Project Operator or Authorized Project Designee may request ARB to make a final

determination if the project meets the requirements in section 95975 to be listed for a renewed crediting period by the Offset Project Registry. In making this determination, ARB may consult with the Offset Project Registry before making the final determination.

(i) Limitations for Crediting Period Renewals. A crediting period may be renewed if the offset project meets the requirements for additionality pursuant to subsections 95975(f) and (h).

(1) The crediting period for non-sequestration projects may be renewed twice for the length of time identified by the Compliance Offset Protocol.

(2) Sequestration projects are not subject to any renewal limits.

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code.
Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

§ 95976. Monitoring, Reporting, and Record Retention Requirements for Offset Projects.

(a) General Requirements for Monitoring Equipment for Offset Projects. The Offset Project Operator or Authorized Project Designee must employ the procedures in the Compliance Offset Protocol for monitoring measurements and project performance for offset projects. All required monitoring equipment must be maintained and calibrated in a manner and at a frequency required by the equipment manufacturer. All modeling, monitoring, sampling, or testing procedures must be conducted in a manner consistent with the applicable procedure.

(b) The Offset Project Operator or Authorized Project Designee must use the missing data methods as provided in a Compliance Offset Protocol for that offset project type, if provided and applicable.

(c) An Offset Project Operator or Authorized Project Designee must put in place all monitoring equipment or mechanisms required by a Compliance Offset Protocol for that offset project type as set forth in:

(1) Compliance Offset Protocol Ozone Depleting Substances Projects, [DATE];

(2) Compliance Offset Protocol Livestock Projects, [DATE];

(3) Compliance Offset Protocol Urban Forest Projects, [DATE]; and

(4) Compliance Offset Protocol U.S. Forest Projects [DATE].

(d) Offset Project Reporting Requirements. An Offset Project Operator or Authorized Project Designee shall submit an Offset Project Data Report to ARB or an Offset Project Registry annually and cover a calendar year. The Offset Project Data Report shall contain the information required by a Compliance Offset Protocol for that offset project type as set forth in:

(1) Compliance Offset Protocol Ozone Depleting Substances Projects [DATE];

(2) Compliance Offset Protocol Livestock Projects [DATE];

(3) Compliance Offset Protocol Urban Forest Projects [DATE]; and

(4) Compliance Offset Protocol U.S. Forest Projects; [DATE]

(5) The Offset Project Operator or Authorized Project Designee must attest, in writing, to ARB as follows:

"I certify under penalty of perjury under the laws of California the GHG reductions and/or GHG removal enhancements for [project] from [date] to [date] are measured in accordance with the [appropriate ARB approved protocol] and all information required to be submitted to ARB in the Offset Project Data Report is true, accurate, and complete."

This attestation may be provided to an Offset Project Registry with the Offset Project Data Report but must be provided to ARB when the requirements in section 95981(d)(1) apply.

(6) All Offset Project Data Reports for the previous year's reported data are due April 1.

(7) If an Offset Project Data Report is not submitted to ARB or an Offset Project Registry by the applicable reporting deadline, the GHG reductions or GHG removal enhancements quantified and reported in the Offset Project Data Report are not eligible to receive offset credits.

(e) Requirements for Record Retention for Offset Projects. An Offset Project Operator or its Authorized Project Designee must meet the following requirements:

(1) The Offset Project Operator or Authorized Project Designee must retain the following documents:

(A) all information submitted as part of the Offset Project Data Report;

(B) documentation of the offset project boundary, including a list of all GHG emissions sources and GHG sinks included in the offset project boundary and the project baseline, and the calculation of the project baseline, project emissions, GHG emission reductions, or GHG removal enhancements;

(C) fuel use and any other underlying measured or sampled data used to calculate project baseline emissions, GHG emission reductions, or GHG removal enhancements for each source, categorized by process and fuel, or material type;

(D) documentation of the process for collecting fuel use or any other underlying measured or sampled data for the offset project and its GHG emissions sources and GHG sinks for quantifying project baseline emissions, project emissions, GHG emission reductions, or GHG removal enhancements;

(E) documentation of all project baseline emissions, project emissions, GHG emission reductions, or GHG removal enhancements;

(F) all point of origin and chain of custody documents required by a Compliance Offset Protocol, if applicable;

(G) all chemical analyses, results, and testing-related documentation for material and sources used for inputs to project baseline emissions, project emissions, GHG emission reductions, or GHG removal enhancements;

(H) all model inputs or assumptions used for quantifying project baseline emissions, project emissions, GHG emission reductions, or GHG removal enhancements;

(I) any data used to asses the accuracy of project baseline emissions, GHG emission reductions, or GHG removal enhancements from each offset project GHG emissions source or GHG sink, categorized by process;

(J) quality assurance and quality control information including information regarding any measurement gaps, missing data substitution, calibrations or maintenance records for monitoring equipment, or models providing data for calculating project baseline emissions, project emissions, GHG emission reductions, or GHG removal enhancements;

(K) a detailed technical description of any offset project continuous measurement/monitoring system, including documentation of any findings and approvals by federal, state, or local agencies;

(L) raw and aggregated data from any measurement system;

(M) documentation of any changes over time and the log book on tests, down-times, calibrations, servicing, and maintenance for any measurement/monitoring equipment providing data for

project baseline calculations, project emissions, GHG emission reductions, or GHG removal enhancements;

(N) for sequestration offset projects, documentation of inventory methodologies and sampling procedures including all calculation methodologies and equations used, and any data related to plot sampling; and

(O) any other documentation or data required to be retained by a Compliance Offset Protocol, if applicable.

(2) Documents shall be retained in paper, electronic, or other usable format for five years after the end of the crediting period for non-sequestration offset projects or, for sequestration offset projects, the length of time that the offset project is issued offset credits plus 100 years.

(3) The documents retained pursuant to this section must be sufficient to allow for the verification of each Offset Project Data Report.

(4) Upon request by ARB or an Offset Project Registry, the Offset Project Operator or Authorized Project Designee must provide to ARB or an Offset Project Registry all documents pursuant to this section, including data used to develop an Offset Project Data Report within 10 calendar days of the request.

(f) General Procedure for Interim Gas or Fuel Analytical and Monitoring Equipment Data Collection. This section only applies if a Compliance Offset Protocol does not already include methods for collecting or accounting for data in the event of missing data due to an unforeseen breakdown of gas or fuel analytical monitoring data equipment.

(1) In the event of an unforeseen breakdown of an offset project data monitoring equipment and gas or fuel flow monitoring devices required for the GHG emission reductions or GHG removal enhancement estimation, ARB may authorize an Offset Project Operator or

Authorized Project Designee to use an interim data collection procedure if ARB determines that the Offset Project Operator or Authorized Project Designee has satisfactorily demonstrated that:

(A) the breakdown may result in a loss of more than 20 percent of the source's gas or fuel data for the year covered by an Offset Project Data Report;

(B) the gas or fuel analytical data monitoring equipment cannot be promptly repaired or replaced without shutting down a process unit significantly affecting the offset project operations, or that the monitoring equipment must be replaced and replacement equipment is not immediately available;

(C) the interim procedure will not remain in effect longer than is reasonably necessary for repair or replacement of the malfunctioning data monitoring equipment; and

(D) the request was submitted within 30 calendar days of the breakdown of the gas or fuel analytical data monitoring equipment.

(2) An Offset Project Operator or Authorized Project Designee seeking approval of an interim data collection procedure must, within 30 calendar days of the monitoring equipment breakdown, submit a written request to ARB that includes all of the following:

(A) the proposed start date and end date of the interim procedure;

(B) a detailed description of what data are affected by the breakdown;

(C) a discussion of the accuracy of data collected during the interim procedure compared with the data collected under the Offset Project Operator's or Authorized Project Designee's usual equipment-based method; and

(D) a demonstration that no feasible alternative procedure exists that would provide more accurate emissions data.

(3) ARB may limit the duration of the interim data collection procedure or include other conditions for approval.

(4) Data collected pursuant to an approved interim data collection procedure shall be considered captured data for purposes of compliance with a Compliance Offset Protocol. When approving an interim data collection procedure, ARB shall determine whether the accuracy of data collected under the procedure is reasonably equivalent to data collected from properly functioning monitoring equipment, and if it is not, the relative accuracy to assign for purposes of assessing possible offset material misstatement under section 95977(e)(2)(C)(xvii) of this article.

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code.
Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

§ 95977. Verification of GHG Emission Reductions or GHG Removal Enhancements from Offset Projects.

(a) General Requirements. An Offset Project Operator or its Authorized Project Designee must obtain the services of an ARB-accredited verification body for the purposes of verifying Offset Project Data Reports submitted under this Article.

(b) Schedule for Verification of Non-Sequestration Offset Projects. The verification of GHG emission reductions or GHG removal enhancements for non-sequestration offset projects must be performed annually and cover a calendar year. If an Offset Project Commencement date is during a calendar year, the verification of GHG emission reductions or GHG

removal enhancements may be included in the verification for the next full calendar year.

(c) Schedule for Verification of Sequestration Offset Projects. The verification of GHG emission reductions or GHG removal enhancements for sequestration offset projects must be performed at least once every six years and may cover up to six years of GHG reductions or GHG removal enhancements by calendar year. After an initial verification with a Positive Offset Verification Statement, reforestation offset projects may defer the second verification for twelve years, but verification of Offset Project Data Reports must be performed at least once every six years thereafter.

(d) Timing for Submittal of Offset Verification Statements to ARB or an Offset Project Registry. Any Offset Verification Statement must be received by ARB or an Offset Project Registry by October 1 of the year in which the Offset Project Data Report was submitted. If the Offset Verification Statement is not submitted to ARB or an Offset Project Registry by the verification deadline, the GHG reductions or GHG removal enhancements quantified and reported in the Offset Project Data Report are not eligible to be issued offset credits.

(e) Requirements for Offset Verification Services.

(1) Rotation of Verification Bodies. An offset project shall not have more than six consecutive years of offset project data verified by the same verification body or verifier(s). An Offset Project Operator or Authorized Project Designee may contract with a previous verification body or verifier(s) only after three years of offset project data have been verified by a different verification body or verifier(s).

(2) Offset Verification Services. GHG emissions, GHG reductions, or GHG removal enhancements from a listed offset project must be verified according to the following verification requirements.

(A) Notice of Verification Services for Offset Projects. Before offset verification services may begin, the verification body must submit a Notice of Verification Services to ARB and an Offset Project Registry, if applicable. The verification body may begin offset verification services for the Offset Project Operator or Authorized Project Designee ten working days after the Notice for Verification Services is received by ARB or the Offset Project Registry, or earlier if approved by ARB in writing. The Notice for Verification Services must include the following information:

(i) the name of the offset project type, including the length of the offset project crediting period, and title of the Compliance Offset Protocol used to implement the offset project;

(ii) a list of staff who will be designated to provide offset verification services as part of an offset verification team, including the names of each designated staff member, the lead verifier, independent reviewer, all subcontractors, and a description of the roles and responsibilities each team member will have during the verification process;

(iii) documentation that the offset verification team has the skills required to provide offset verification services for the Offset Project Operator or Authorized Project Designee. At least one offset verification team member must be accredited by ARB as an offset project specialist for an offset project of that type; and

(iv) general information on the Offset Project Operator or Authorized Project Designee, including:

a. the name of the Offset Project Operator or Authorized Project Designee, including contact information, address, telephone number, and E-mail address;

b. the locations that will be subject to offset verification services;

c. the date(s) of on-site visits, with address and contact information; and

d. a brief description of expected offset verification services to be performed, including expected completion date.

(B) If any information submitted pursuant to sections 95977(e)(2)(A)(ii) and 95977(e)(2)(A)(iv) changes after the Notice for Verification Services is submitted to ARB and the Offset Project Registry, if applicable, the verification body must notify ARB and the Offset Project Registry, if applicable, at least five days prior to the start of offset verification services. If any information submitted pursuant to sections 95977(e)(2)(A)(ii) and 95977(e)(2)(A)(iv) changes during verification services, the verification body must notify ARB and the Offset Project Registry, if applicable, before the offset verification statement is provided to ARB or the Offset Project Registry.

(C) Offset verification services must include the following:

(i) Verification Plan for Offset Projects. The offset verification team must obtain information from the Offset Project Operator or Authorized Project Designee necessary to develop a Verification Plan. Such information must include the following:

a. information to allow the offset verification team to develop a general understanding of offset project boundaries, operations, project baseline emissions, and annual GHG reductions or GHG removal enhancements;

b. information regarding the training or qualifications of personnel involved in developing the Offset Project Data Report;

c. the name and date of the Compliance Offset Protocol used to quantify and report project baselines, GHG reductions, GHG removal enhancements, and other required data as applicable in the Compliance Offset Protocol; and

d. information about any data management system, offset project monitoring system, and models used to track project baselines, GHG reductions, GHG removal enhancements, and other required data as applicable in the Compliance Offset Protocol.

(ii) The offset verification team must develop an Offset Verification Plan that includes, at a minimum:

a. dates of proposed meetings and interviews with personnel related to the offset project;

b. dates of proposed site visits;

c. types of proposed document and data reviews; and

d. expected date for completing offset verification services.

(iii) The offset verification team must discuss with the Offset Project Operator or Authorized Project Designee the scope of the offset verification services and request any information and documents needed for initial offset verification services. The offset verification team must review the documents submitted and plan and conduct a review of original documents and supporting data for the Offset Project Data Report.

(iv) Site Visits for Offset Projects. For a non-sequestration offset project, at least one accredited offset verifier in the offset verification team, including the project specialist, must make at least one site visit every year to each offset project location for which an Offset Project Data Report is submitted. For a forest or urban forest offset project, at least one accredited offset verifier in the offset verification team, including the project specialist, must make a site visit every year that offset verification services are provided. A site visit is also required after the first full calendar year of operations of an offset project. During the site visit, the offset verification team member(s) must conduct the following:

a. during the initial site visit the offset verification team members must:

(i) assess offset project eligibility and additionality according to section 95973 and the applicable Compliance Offset Protocol;

(ii) confirm that the project boundary is appropriately defined;

(iii) review project baseline calculations and modeling;

(iv) assess the operations, functionality, data control systems, and review GHG measurement and monitoring techniques; and

(v) confirm that all applicable eligibility criteria to design, measure, and monitor the offset project conforms to the requirements of the applicable Compliance Offset Protocol; and

b. during the initial and each subsequent site visit the offset verification team must:

(i) check that all project boundaries, GHG emissions sources, GHG sinks, and GHG reservoirs in the applicable Compliance Offset Protocol are identified appropriately;

(ii) review and understand the data management systems used by the Offset Project Operator or Authorized Project Designee to track, quantify, and report GHG reductions, GHG removal enhancements, or other data required as applicable in the Compliance Offset Protocol. This includes reviewing data collection processes and procedures, sampling techniques and metering accuracy, quality assurance/quality control processes and procedures; and missing data procedures. The offset verification team member(s) must evaluate the uncertainty and effectiveness of these systems;

(iii) interview key personnel involved in collecting offset project data and preparing the Offset Project Data Report;

(iv) make direct observations of equipment for data sources and equipment supplying data for sources in the sampling plan determined to be high risk;

(v) collect and review other information that, in the professional judgment of the team, is needed in the verification process;

(vi) confirm the offset project conforms with all local, state, or federal environmental regulatory requirements; and

(vii) review all chain of custody documents as required in the Compliance Offset Protocol, if applicable.

(viii) If the offset project is found by the offset verification team to not meet the requirements of section 95977(e)(2)(C)(iv)(b.)(vi) the offset project is ineligible to

receive offset credits for GHG reductions or GHG removals quantified and reported in the Offset Project Data Report.

(v) The offset verification team must review offset project operations to identify applicable GHG emissions sources, project emissions, GHG sinks, and GHG reservoirs required to be included and quantified in the Offset Project Data Report as required by the applicable Compliance Offset Protocol. This must include a review of the GHG emissions inventory and each type of GHG emissions source and GHG sink to ensure that all GHG emissions sources, GHG sinks, and GHG reservoirs required to be reported for the offset project are properly included in the Offset Project Data Report.

(vi) An offset Project Operator or Authorized Project Designee must make available to the offset verification team all information and documentation used to calculate and report project baseline and annual GHG emissions, GHG reductions, and GHG removal enhancements and other information required by the applicable Compliance Offset Protocol.

(vii) Sampling Plan for Offset Project Data Reports. As part of confirming the Offset Project Data Report, the offset verification team must develop a sampling plan that meets the following requirements:

a. The offset verification team must develop a sampling plan based on a strategic analysis developed from document reviews and interviews to assess the likely nature, scale, and complexity of the offset verification services for an Offset Project Operator or Authorized

Project Designee. The analysis must review the inputs for the development of the submitted Offset Project Data Report, the rigor and appropriateness of the GHG data management system, and the coordination within an Offset Project Operator's or Authorized Project Designee's organization to manage the operation and maintenance of equipment and systems used to develop the Offset Project Data Reports;

b. The offset verification team must include a ranking of GHG emissions sources, GHG sinks, and GHG reservoirs within the offset project boundary by amount of contribution to total CO_2e emissions, GHG reductions, or GHG removal enhancements, and a ranking of GHG emissions sources, GHG sinks, or GHG reservoirs with the largest calculation uncertainty; and

c. The offset verification team must include a qualitative narrative of uncertainty risk assessment in the following areas as applicable to the Compliance Offset Protocol:

(i) data acquisition equipment;

(ii) data sampling and frequency;

(iii) data processing and tracking;

(iv) project baseline and annual GHG emissions, GHG reductions, and GHG removal enhancement calculations;

(v) data reporting;

(vi) chain of custody requirements; and

(vii) management policies or practices in developing Offset Project Data Reports.

(viii) After completing the analysis in sections 95977(e)(2)(C)(vii)(a.) through 95977(e)(2)(C)(vii)(c.), the

offset verification team must include in the sampling plan a list which includes the following:

a. GHG emissions sources, GHG sinks, and GHG reservoirs that will be targeted for document reviews to ensure conformance with the Compliance Offset Protocol and data checks as specified in 95977(e)(2)(C)(xii), and an explanation of why they were chosen;

b. methods used to conduct data checks for each GHG emissions source, GHG sinks, and GHG reservoirs; and

c. a summary of the information analyzed in the data checks and document reviews conducted for each GHG emissions source, GHG sink, or GHG reservoir.

(ix) The sampling plan list prepared pursuant to section 95977(e)(2)(C)(viii) must be updated and finalized prior to the completion of verification services.

(x) The offset verification team must revise the sampling plan to describe tasks completed or needed to be completed by the verification team as relevant information becomes available and potential issues emerge of offset material misstatement or nonconformance with the requirements of the Compliance Offset Protocol and this subarticle.

(xi) The verification body must retain the sampling plan in paper, electronic, or other format for a period of not less than ten years following the submission of each Offset Verification Statement. The sampling plan must be made available to ARB or the Offset Project Registry within 10 days upon request. The verification body must also retain all material received, reviewed, or generated to render an Offset Verification Statement for an Offset Project Operator or

Authorized Project Designee for ten years following the submittal of each Offset Verification Statement. The documentation must allow for a transparent review of how a verification body reached its conclusion in the Offset Verification Statement.

(xii) Data Checks for Offset Project Data Reports. To determine the reliability of the submitted Offset Project Data Report, the offset verification team must use data checks. Such data checks must focus first on the largest and most uncertain estimates of project baseline GHG emissions, project emissions, GHG reductions, or GHG removal enhancements, and the offset verification team must:

a. use data checks to ensure that the appropriate methodologies and GHG emission factors have been applied in calculating the project baseline and annual GHG emissions, project emissions, GHG reductions, or GHG removal enhancement calculations in the Compliance Offset Protocol;

b. chose GHG emissions sources, project emissions, GHG sinks, and GHG reservoirs for data checks based on their relative sizes and risks of offset material misstatement or nonconformance as indicated in the sampling plan;

c. use professional judgment in the number of data checks required for the offset verification team to conclude with reasonable assurance whether the Offset Project Operator's or Authorized Project Designee's total annual reported GHG reductions or GHG removal enhancements are free of offset material misstatement and the Offset Project Data Report otherwise conforms to

the requirements of the Compliance Offset Protocol and this subarticle. At a minimum a data check must include the following:

(i) tracing data in the Offset Project Data Report to its origin;

(ii) looking at the process for data compilation and collection;

(iii) reviewing all GHG inventory designs, and sampling procedures, if applicable;

(iv) recalculating GHG emissions, project emissions, GHG reductions, or GHG enhanced removals estimates to check original calculations;

(v) reviewing calculation methodologies used by the Offset Project Operator or Authorized Project Designee for conformance with the Compliance Offset Protocol and this subarticle;

(vi) reviewing meter and fuel analytical instrumentation calibration, if applicable; and

(vii) reviewing the quantification from models approved for use in the Compliance Offset Protocol, if applicable; and

d. compare its own calculated results with the reported offset project data in order to confirm the extent and impact of any omissions and errors. Any discrepancies must be investigated. The comparison of data checks must provide enough detail to indicate which GHG emissions sources, GHG sinks, and GHG reservoirs were checked, the types and quantity of data that were evaluated for each GHG emissions source, GHG sink,

and GHG reservoir, and any discrepancies that were identified.

(xiii) Offset Project Data Report Modifications. As a result of review by the offset verification team and prior to completion of an Offset Verification Statement, the Offset Project Operator or Authorized Project Designee must make any possible improvements or corrections to the submitted Offset Project Data Report, and a revised Offset Project Data Report must be submitted to ARB or the Offset Project Registry. Documentation for all Offset Project Data Report submittals must be retained by the Offset Project Operator or Authorized Project Designee for the length of time specified in section 95976(e)(2).

(xiv) To verify that the Offset Project Data Report is free of offset material misstatement, the offset verification team must make its own determination of GHG reductions or GHG removal enhancements relative to the project baseline, and must determine whether there is reasonable assurance that the Offset Project Data Report does not contain an offset material misstatement for the Offset Project Operator or Authorized Project Designee, on a CO_2e basis. To assess conformance with this subarticle and the Compliance Offset Protocol the offset verification team must review the methods and factors used to develop the Offset Project Data report for adherence to the requirements of this subarticle and the Compliance Offset Protocol.

(xv) Issues Log. The offset verification team must keep a log of any issues identified in the course of offset verification activities that may affect determinations of offset material

misstatement and nonconformance. The issues log must identify the section of this subarticle or Compliance Offset Protocol related to the nonconformance, if applicable, and indicate if the issues were corrected by the Offset Project Operator or Authorized Project Designee prior to completing the offset verification services. Any other concerns that the offset verification team has with the preparation of the Offset Project Data Report must be documented in the issues log. The issues log must indicate whether the issues could have any bearing on offset material misstatement or conformance.

(xvi) An assessment of offset material misstatement is conducted for annual net GHG reductions or GHG removal enhancements relative to the project baseline in metric tons of CO_2e.

(xvii) The offset verification team must determine whether the GHG reductions or GHG removal enhancements quantified and reported in the Offset Project Data Report contain an offset material misstatement using the following equation:

$$Percent\ accuarcy = 100\% - \sum \frac{[Errors + Omissions + Misreporting]\ x\ 100\%}{Total\ reported\ emissions}$$

Where:

"Errors" means any differences between the reported GHG emissions, project emissions, GHG reductions, or GHG removal enhancements and GHG emissions, project emissions, GHG reductions, or GHG removal enhancements for a data source subject to data checks in 95977(e)(2)(C)(xii) calculated by the offset verification team.

"Omissions" means any GHG emissions, GHG reductions, project emissions, or GHG removal enhancements that the offset verification team concludes must be part of the Offset Project Data Report, but were not included by the Offset Project Operator or Authorized Project Designee in the Offset Project Data Report.

"Misreporting" means duplicative, incomplete, or other GHG emissions, project emissions, GHG reductions, or GHG removal enhancements the offset verification team concludes should, or should not, be part of the Offset Project Data Report.

"Total reported emissions" means annual reported net GHG reductions or GHG removal enhancements relative to the project baseline in metric tons CO_2e.

(xviii) Completion of offset verification services must include:

a. Offset Verification Statement. Upon completion of the offset verification services pursuant to section 95977(e)(2) the verification body must complete an Offset Verification Statement, and provide it to the Offset Project Operator or Authorized Project Designee and ARB or the Offset Project Registry by the verification deadline pursuant to section 95977(d). Before the Offset Verification Statement is completed, the verification body must have the offset verification services and findings of the offset verification team independently reviewed within the verification body by an independent reviewer not

involved in verification services for that Offset Project Operator or Authorized Project Designee during that year.

b. The independent reviewer shall serve as the final check of the offset verification team's work to identify any significant concerns, including:

(i) errors in planning;

(ii) errors in data sampling; and

(iii) errors in judgment by the offset verification team that are related to the draft offset verification statement.

c. The independent reviewer must maintain independence from the offset verification services by not making specific recommendations about how the offset verification services should be conducted. The independent reviewer will review documents relevant to the offset verification services provided and identify any failure to comply with the requirements of this subarticle or with the verification body's internal policies and procedures for providing offset verification services. The independent reviewer must concur with the verification findings before the Offset Verification Statement can be issued.

d. When the offset verification team completes its findings:

(i) The verification body must provide to the Offset Project Operator or Authorized Project designee a detailed verification report. The detailed verification report must at a minimum include the verification plan, the detailed comparison of the data checks conducted during offset verification services, the issues log identified in the course of

verification activities and the issue resolutions, and any qualifying comments on findings during offset verification services. The detailed verification report must also include the calculations performed in 95977(e)(2)(C)(xvii) and be made available to ARB or the Offset Project Registry within 10 days upon request.

(ii) The verification body must provide the Offset Verification Statement to the Offset Project Operator or Authorized Project Designee and ARB or the Offset Project Registry, attesting to ARB whether the verification body has found the submitted Offset Project Data Report to be free of offset material misstatement, and whether the Offset Project Data Report is in conformance with the requirements of this subarticle and the Compliance Offset Protocol.

(iii) In the case of a Qualified Positive Offset Verification Statement, the verification body will qualify the Offset Verification Statement to indicate any non-conformances contained within the Offset Project Data Report and that these non-conformances do not result in an offset material misstatement.

(iv) The offset verification team must have a final discussion with the Offset Project Operator or Authorized Project Designee explaining their findings and notifying the Offset Project Developer or Authorized Project Designee of any unresolved issues noted in the issues log before the Offset Verification Statement is finalized.

(v) The lead verifier in the offset verification team must attest to ARB in the offset verification statement that the offset verification team has carried out all offset verification

services as required by this subarticle, and the lead verifier who has conducted the independent review of offset verification services and findings must attest to his or her independent review on behalf of the verification body and his or her concurrence with the offset verification findings.

(vi) The lead verifier must attest in the offset verification statement, in writing, to ARB as follows:

"I certify under penalty of perjury under the laws of California the offset verification team has carried out all offset verification services as required by section 95977 and the findings are true, accurate, and complete and have been independently reviewed by an independent reviewer as required under sections 95977(e)(2)(C)(xviii)(a.) - 95977(e)(2)(C)(xviii)(c.)."

(xix) Prior to the verification body providing an Adverse Offset Verification Statement to ARB or the Offset Project Registry, the Offset Project Operator or Authorized Project Designee must be provided at least ten working days to modify the Offset Project Data report to correct any offset material misstatement or nonconformance found by the offset verification team. The modified report and Offset Verification Statement must be submitted to ARB or the Offset Project Registry before the applicable verification deadline, unless the Offset Project Operator or Authorized Project Designee makes a request to ARB or an Offset Project Registry pursuant to section 95977(e)(2)(C)(xix)(a.)

a. If the Offset Project Operator or Authorized Project Designee and the verification body cannot reach agreement on modifications to the Offset Project Data

Report that result in a Positive Offset Verification or Qualified Positive Offset Verification Statement, due to a disagreement on the requirements of this article or Compliance Offset Protocol, the Offset Project Operator or Authorized Project Designee may petition the Executive Officer or Offset Project Registry to make a decision as to the verifiability of the submitted Offset Project Data Report.

b. If the Executive Officer or Offset Project Registry determines that the Offset Project Data Report does not meet the standards and requirements specified in this article, the Offset Project Operator or Authorized Project Designee shall have the opportunity to submit within 30 calendar days of the date of this decision any Offset Project Data Report revisions that address the Executive Officer's or Offset Project Registry's determination, for re-verification of the Offset Project Data Report. In re-verifying a revised Offset Project Data Report, the verification body and offset verification team shall be subject to the requirements in sections 95977(e)(2)(C)(xviii)(a.) through 95977(e)(2)(C)(xviii)(d.), and must submit the revised Offset Verification Statement to ARB or the Offset Project Registry within 15 days.

c. If the Offset Project Operator or Authorized Project Designee disagrees with a determination made by an Offset Project Registry, they can re-initiate the dispute resolution process in section 95977(e)(2)(C)(xix)(a.) through the Executive Officer.

(i) The process must be reinitiated within 60 days of the applicable verification deadline.

(ii) The Executive Officer, verification body, Offset Project Operator or Authorized Project Designee shall be held to the requirements in section 95977(e)(2)(C)(xix)(b.).

(xx) Upon submission of the Offset Verification Statement to ARB or the Offset Project Registry, the Offset Project Data Report must be considered final and no further changes may be made. All verification requirements of this article shall be considered complete.

(xxi) If the Executive Officer finds a high level of conflict of interest existed between a verification body and an Offset Project Operator or Authorized Project Designee, or an Offset Project Data Report that received a Positive Offset or Qualified Positive Offset Verification Statement fails an ARB audit, the Executive Officer may set aside the Positive Offset or Qualified Positive Offset Verification Statement submitted by the verification body and require the Offset Project Operator or Authorized Project designee to have the Offset Project Data Report re-verified by a different verification body within 90 calendar days of this finding.

(xxii) Upon request by the Executive Officer or the Offset Project Registry, the Offset Project Operator or Authorized Project Designee must provide the data used to generate an Offset Project Data Report, including all data available to the offset verification team in the conduct of offset verification services within 10 working days of the request.

(xxiii) Upon request by the Executive Officer or the Offset Project Registry the verification body must provide ARB or the Offset

Project Registry the detailed verification report given to the Offset Project Operator or Authorized Project Designee, as well as the sampling plan and any other supporting documentation. All documentation must be provided by the verification body to the Executive Officer or the Offset Project Registry within 10 working days of the request.

(xxiv) Upon written notification by ARB the verification body must make itself available for an offset verification services audit when providing Offset Verification Services for a project using a Compliance Offset Project protocol listed with ARB or an Offset Project Registry.

(f) Additional Project-Specific Requirements for Offset Verification Services. In addition to meeting the verification requirements in this section, GHG emission reductions or GHG removals resulting from an offset project must also meet any additional verification requirements in the Compliance Offset Protocol, if applicable for an offset project of that type.

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code.
Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

§ 95978. Offset Verifier and Verification Body Accreditation.

A verifier or verification body must meet the accreditation requirements in title 17, article 2, section 95132 to provide verification services to verify GHG emission reductions or GHG removal enhancements for offset projects listed pursuant to this article.

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code.
Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

§ 95979. Conflict of Interest Requirements for Verification Bodies for Verification of Offset Project Data Reports.

(a) The conflict of interest provisions of this section shall apply to verification bodies, lead verifiers, and verifiers accredited by ARB to perform verification services.

(b) The potential for a conflict of interest shall be deemed to be high where:

(1) the verification body and Offset Project Operator or Authorized Project Designee share any senior management staff or board of directors membership, or any of the senior management staff of the Offset Project Operator or Authorized Project Designee have been employed by the verification body, or vice versa, within the previous three years; or

(2) within the previous three years, any staff member of the verification body or any related entity has provided to the Offset Project Operator or Authorized Project Designee any of the following non-offset verification services:

(A) designing, developing, implementing, reviewing, or maintaining an inventory or offset project information or data management system for air emissions, unless the review was part of providing GHG offset verification services;

(B) developing GHG emission factors or other GHG-related engineering analysis, including developing or reviewing a California Environmental Quality Act (CEQA) GHG analysis that includes offset project specific information;

(C) designing energy efficiency, renewable power, or other projects which explicitly identify GHG reductions or GHG removal enhancements as a benefit;

(D) designing, developing, implementing, internally auditing, consulting, or maintaining a GHG emission reduction or GHG enhanced removal offset project;

(E) owning, buying, selling, trading, or retiring shares, stocks, or GHG offset credits from the offset project;

(F) dealing in or being a promoter of offset credits on behalf of an Offset Project Operator or Authorized Project Designee;

(G) preparing or producing GHG-related manuals, handbooks, or procedures specifically for the Offset Project Operator or Authorized Project Designee;

(H) appraisal services of carbon or GHG liabilities or assets;

(I) brokering in, advising on, or assisting in any way in carbon or GHG-related markets;

(J) directly managing any health, environment or safety functions for the Offset Project Operator or Authorized Project Designee;

(K) bookkeeping or other services related to the accounting records or financial statements;

(L) any service related to information systems, including 14001 certification, unless those systems will not be part of the verification process;

(M) appraisal and valuation services, both tangible and intangible;

(N) fairness opinions and contribution-in-kind reports in which the verification body has provided its opinion on the adequacy of consideration in a transaction, unless the resulting services will not be part of the verification process;

(O) any actuarially oriented advisory service involving the determination of amounts recorded in financial statements and related accounts;

(P) any internal audit service that has been outsourced by the Offset Project Operator or Authorized Project Designee that relates to the Offset Project Operator's or Authorized Project Designee's internal accounting controls, financial systems, or financial statements, unless the result of those services will not be part of the verification process;

(Q) acting as a broker-dealer (registered or unregistered), promoter, or underwriter on behalf of the Offset Project Operator or Authorized Project Designee;

(R) any legal services;

(S) expert services to the Offset Project Operator or Authorized Project Designee or a legal representative for the purpose of advocating the Offset Project Operator's or Authorized Project Designee's interests in litigation or in a regulatory or administrative proceeding or investigation, unless providing factual testimony; and

(T) any regulatory enforcement action, including citations and fines.

"Member" for the purposes of this section means any employee or subcontractor of the verification body or related entities of the verification body. "Member" also includes any individual with majority equity share in the verification body or its related entities.

"Related entity" for the purposes of this section means any direct parent company, direct subsidiary, or sister company.

(3) The potential for conflict of interest will be deemed to be high when any member of the verification body provides any type of incentive to an Offset Project Operator or Authorized Project Designee to secure an offset verification services contract.

(4) The potential for a conflict of interest will also be deemed to be high where any member of the verification body has provided offset verification services for the Offset Project Operator or Authorized Project Designee within the last three years, except within the time periods in which the Offset Project Operator or Authorized Project Designee is allowed to use the same verification body as specified in sections 95977(e)(1).

(c) The potential for a conflict of interest must be deemed to be low where no potential for a conflict of interest is found under section 95979(b) and any non-offset verification services provided by any member of the verification body to the Offset Project Operator or Authorized Project Designee within the last three years are valued at less than 20 percent of the fee for the proposed verification.

(d) The potential for a conflict of interest must be deemed to be medium where the potential for a conflict of interest is not deemed to be either high or low as specified in sections 95979(b) and 95979(c), or where there are any instances of personal or familial relationships between the verification body and management or employees of the Offset Project Operator or Authorized Project Designee.

If a verification body identifies a medium potential for conflict of interest and wishes to provide offset verification services for the Offset Project Operator or Authorized Project Designee for an offset project listed with ARB or an Offset Project Registry, the verification body must submit, in addition to the submittal requirements specified in section 95979(e), a plan to avoid, neutralize, or mitigate the potential conflict of interest situation. At a minimum, the conflict of interest mitigation plan must include:

(1) a demonstration that any members with potential conflicts have been removed and insulated from the project;

(2) an explanation of any changes to the organizational structure or verification body to remove the potential conflict of interest. A demonstration that any unit with potential conflicts has been divested or moved into an independent entity or any subcontractor with potential conflicts has been removed; and

(3) any other circumstance that specifically addresses other sources for potential conflict of interest.

(e) Conflict of Interest Submittal Requirements for Accredited Verification Bodies. Before providing any offset verification services, the verification body must submit to the Offset Project Operator or Authorized Project Designee and ARB or the Offset Project Registry a self-evaluation of the potential for any conflict of interest that the verification body, its staff, its related entities, or any subcontractors performing offset verification services may have with the Offset Project Operator or Authorized Project Designee for which it will perform offset verification services. The submittal must include the following:

(1) identification of whether the potential for conflict of interest is high, low, or medium based on factors specified in sections 95979(b), (c), and (d);

(2) identification of whether any member of the offset verification team has previously provided offset verification services for the Offset Project Operator or Authorized Project Designee, and, if so, the years in which such offset verification services were provided; and

(3) identification of whether any member of the offset verification team or related entity has engaged in any non-offset verification services of any nature with the Offset Project Operator or Authorized Project Designee either within or outside California during the previous three years. If non-offset verification services have previously been provided, the following information must also be submitted:

(A) identification of the nature and location of the work performed for the Offset Project Operator or Authorized Project Designee and whether the work is similar to the type of work to be performed during verification;

(B) the nature of past, present, or future relationships with the Offset Project Operator or Authorized Project Designee including:

(i) instances when any member of the offset verification team has performed or intends to perform work for the Offset Project Operator or Authorized Project Designee;

(ii) identification of whether work is currently being performed for the Offset Project Operator or Authorized Project Designee, and if so, the nature of the work;

(iii) how much work was performed for the Offset Project Operator or Authorized Project Designee in the last three years, in dollars;

(iv) whether any member of the offset verification team has any contracts or other arrangements to perform work for the Offset Project Operator or Authorized Project Designee or a related entity; and

(v) how much work related to GHG reductions or GHG enhanced removals the offset verification team has performed for the Offset Project Operator or Authorized Project Designee or related entities in the last three years, in dollars;

(C) explanation of how the amount and nature of work previously performed is such that any member of the offset verification team's credibility and lack of bias should not be under question;

(D) a list of names of the staff that would perform offset verification services for the Offset Project Operator or Authorized Project Designee, and a description of any instances of personal or family relationships with management or employees of the Offset Project Operator or Authorized Project Designee that potentially represent a conflict of interest;

(E) identification of any other circumstances known to the verification body, or Offset Project Operator or Authorized Project Designee that could result in a conflict of interest; and

(F) attest, in writing, to ARB as follows:
"I certify under penalty of perjury of the laws of California the information provided in the Conflict of Interest submittal is true, accurate, and complete."

(f) Monitoring Conflict of Interest Situations.

(1) After commencement of offset verification services, the verification body must monitor and immediately make full disclosure, in writing, to ARB or the Offset Project Registry regarding any potential for a conflict of interest situation that arises for a project using a Compliance Offset Protocol. This disclosure must include a description of actions that the verification body has taken or proposes to take to avoid, neutralize, or mitigate the potential for a conflict of interest.

(2) The verification body must monitor arrangements or relationships that may be present for a period of one year after the completion of offset verification services for a project using a Compliance Offset Protocol. During that period, within 30 days of entering into any contract with the Offset Project Operator or Authorized Project Designee for which the verification body has provided offset verification services, the verification body must notify ARB or the Offset Project Registry of the contract and the nature of the work to be performed. ARB or the Offset

Project Registry, within 30 working days, will determine the level or conflict using the criteria in sections 95979(a) through (d), if the Offset Project Operator or Authorized Project Designee must re-verify their Offset Project Data Report, and if accreditation revocation is warranted by ARB.

(3) The verification body must notify ARB or the Offset Project Registry within 30 days, of any emerging conflicts of interest during the time offset verification services are being provided for a project using a Compliance Offset Protocol.

(A) If ARB or the Offset Project Registry determines that an emerging potential conflict disclosed by the verification body is medium risk, and this risk can be mitigated, then the verification body meets the conflict of interest requirements to continue to provide offset verification services for the Offset Project Operator or Authorized Project Designee.

(B) If ARB or the Offset Project Registry determines that an emerging potential conflict disclosed by the verification body is medium or high risk, and this risk cannot be mitigated, then the verification body will not be able to continue to provide offset verification services for the Offset Project Operator or Authorized Project Designee, and may be subject to the suspension or revocation of accreditation by ARB under title 17, article 2, section 95132(d).

(4) The verification body must report to ARB and the Offset Project Registry, if applicable, any changes in its organizational structure, including mergers, acquisitions, or divestitures, for one year after completion of offset verification services.

(5) ARB may invalidate a Positive of Qualified Positive Offset Verification Statement received in section 95981(d) if it discovers a potential

conflict of interest has arisen for any member of the offset verification team. In such a case, the Offset Project Operator or Authorized Project designee shall be provided 90 calendar days to complete re-verification.

(6) If the verification body or its subcontractor(s) are found to have violated the conflict of interest requirements of this article, the Executive Officer may rescind accreditation of the body, its verifier staff, or its subcontractor(s) for any appropriate period of time as provided in title 17, article 2, section 95132(d).

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code.
Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

§ 95980. Issuance of Offset Credits.

(a) One offset credit, which represents one metric ton of CO_2e for a direct GHG emission reduction or direct GHG removal enhancement, will be issued only if:

(1) ARB or an Offset Project Registry has listed the offset project pursuant to section 95975;

(2) the GHG emission reductions or GHG removal enhancements were issued a Positive Offset or Qualified Positive Offset Verification Statement pursuant to section 95977; and

(3) ARB or an Offset Project Registry has received a Positive Offset or Qualified Positive Offset Verification Statement issued and attested to by an ARB-accredited verification body for the time period for which offset credits would be issued.

(b) Determination for Timing and Duration of Initial Crediting Periods. The initial crediting period will begin with the date that the first verified emission reductions or removal enhancements occur, according to the first Positive

Offset or Qualified Positive Offset Verification Statement that is received by ARB or an Offset Project Registry.

(c) Determination for Timing and Duration of Renewed Crediting Periods. A renewed crediting period will begin the day after the conclusion of the prior crediting period.

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code.
Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

§ 95981. Process for Issuance of Offset Credits.

(a) ARB or an Offset Project Registry will issue an offset credit that meets the requirements of section 95980 to an Offset Project Operator, Authorized Project Designee, or any other third party authorized by the Offset Project Operator pursuant to section 95974(a)(1), no later than 45 calendar days after a Positive Offset or Qualified Positive Offset Verification Statement is received by ARB or an Offset Project Registry.

(b) Change of Listing Status. When ARB or an Offset Project Registry issues an offset credit for an offset project, the listing status for that offset project will be changed to either "Active Project" or "Active Renewal."

(c) Notice of Determination of Issuance of Offset Credits. Not later than 15 calendar days after ARB or an Offset Project Registry issues an offset credit, ARB or an Offset Project Registry will notify the Offset Project Operator, Authorized Project Designee, or any other third party authorized by the Offset Project Operator pursuant to section 95974(a)(1) of the issuance.

(d) Requirements for Offset Projects Submitted Through an Offset Project Registry Seeking Issuance of ARB Offset Credits.

(1) If an Offset Project Operator or Authorized Project Designee provides information for listing pursuant to section 95975, monitors and reports pursuant to section 95976, and has their offset project verified pursuant to section 95977 through an Offset Project Registry, the Offset Project Operator or Authorized Project Designee must provide the following information to ARB for issuance of ARB offset credits:

(A) the attestations required in sections 95975(b)(1), 95975(b)(2), 95976(d)(5), 95977(e)(2)(C)(xviii)(d.)(ii), 95977(e)(2)(C)(xviii)(d.)(v), and 95977(e)(2)(C)(xviii)(d.)(vi);

(B) offset project listing information submitted to an Offset Project Registry pursuant to sections 95975(b) and (c);

(C) offset project data reports submitted to an Offset Project Registry pursuant to section 95976(d);

(D) verification statement submitted pursuant to section 95977(e)(2)(C)(xviii)(d.)(ii);

(E) the detailed verification report required in section 95977(e)(2)(C)(xviii)(d.)(i.)

(F) attest, in writing, to ARB as follows:
"I certify under penalty of perjury of the laws of California all information provided to ARB for issuance of offset credits is true, accurate, and complete."

(2) ARB will notify the Offset Project Operator, Authorized Project Designee, or other third party identified in section 95974(a)(1) within 30 calendar days if the information in section 95981(d)(1) is complete or request additional specific information.

(3) Within 30 calendar days of determining the information submitted in section 95981(d)(1) is complete, ARB will issue offset credits that meet the requirements of section 95980.

(4) ARB may request any additional information from the Offset Project Operator, Authorized Project Designee, Offset Project Registry, or verification body before issuing offset credits that meet the requirements of section 95980.

(5) If ARB determines the information submitted in sections 95981(d)(1) and (d)(4) does not meet the requirements for issuance of ARB offset credits, then the Offset Project Designee or Authorized Project Operator may petition the Executive Officer, within 10 days of denial, for a review of submitted information in section 95981(d)(1) and (d)(4) and respond to any issues that prevent the issuance of ARB offset credits.

(6) The Executive Office must make a final determination within 30 calendar days of receiving the request in section 95981(d)(5) and may request additional information from the Offset Project Operator or Authorized Project Designee, verification body, or Offset Project Registry. This determination made by the Executive Officer is final.

(e) If the offset credits issued pursuant to section 95981(a) originated from an offset project submitted through an Offset Project Registry, the Offset Project Registry must retire the original offset credits issued by the Offset Project Registry in its system before ARB registers the offset credits pursuant to section 95982.

(f) Receipt of Offset Credits Issued by ARB. ARB will transfer the offset credits into the Holding Account of the Offset Project Operator, Authorized Project Designee, or any other third party authorized by the Offset Project Operator pursuant to section 95974(a)(1), within 15 working days of the notice of determination pursuant to sections 95981(c) and (d).

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code.
Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

§ 95982. Registration of Offset Credits Issued by ARB.

An offset credit issued by ARB will be registered by:

(a) creating a unique ARB serial number; and

(b) transferring this serial number to the Holding Account of the listed Offset Project Operator, Authorized Project Designee, or another third party as provided in section 95974(a)(1) unless otherwise required by section 95983.

§ 95983. Offset Reversals.

(a) For forest sequestration projects, a portion of the offset credits issued by ARB must be placed into the Forest Buffer Account, or if the offset project is originally submitted through an Offset Project Registry the portion of the offset credits issued by the Offset Project Registry must be transferred to ARB for placement in the Forest Buffer Account.

(1) The amount that must be placed in the Forest Buffer Account upon credit issuance shall be determined as set forth in Compliance Offset Protocol for Forest Projects [DATE].

(2) Offset credits will be transferred to the Forest Buffer Account by ARB at the time of offset credit registration pursuant to section 95982.

(3) If a forest offset project is originally submitted through an Offset Project Registry, all offset credits that should be set aside into the Forest Buffer Account must be transferred to ARB by the Offset Project Registry. The Offset Project Registry must retire the original offset credits issued by the Offset Project Registry in its system.

(b) Unintentional Reversals. If the Offset Project Operator or Authorized Project Designee determines there has been any unintentional reversal, it

must notify ARB, in writing, of the reversal within six months of its discovery.

(1) In the case of an unintentional reversal the Offset Project Operator or Authorized Project Designee shall, provide in writing:

(A) an explanation of the nature of the unintentional reversal; and

(B) a verified estimate of current carbon stocks within the offset project boundary within one year of the discovery of the unintentional reversal.

(2) If ARB determines that there has been an unintentional reversal, it will retire a quantity of offset credits pursuant to section 95985(e).

(c) Intentional Reversals. Requirements of the Offset Project Operator or Authorized Project Designee for intentional reversals are as follows:

(1) If an intentional reversal occurs, the Offset Project Operator or Authorized Project Designee shall, within 30 calendar days of the intentional reversal:

(A) give notice, in writing, to ARB of the intentional reversal; and

(B) provide a written description and explanation of the intentional reversal to ARB.

(2) After ARB receives written notice by the Offset Project Operator or Authorized Project Designee, ARB will determine if an intentional reversal has occurred, and notify, in writing, the Offset Project Operator or Authorized Project Designee of its determination.

(3) Within three months of receiving the notice for intentional reversal from ARB, the Offset Project Operator or Authorized Project Designee shall submit a verified estimate of current carbon stocks within the offset project boundary.

(d) Disposition of Forest Sequestration Projects After an Unintentional Reversal. If a reversal lowers the forest offset project's actual standing

live carbon stocks below its project baseline, the forest offset project will automatically be terminated by ARB or an Offset Project Registry.

(1) If the forest offset project is automatically terminated due to an unintentional reversal, another offset project may be initiated and submitted to ARB or an Offset Project Registry for listing within the same offset project boundary.

(2) If the forest offset project has experienced an unintentional reversal and its actual standing live carbon stocks are still above the approved baseline levels, it may continue without termination as long as the unintentional reversal has been compensated by the Forest Buffer Account. The offset project must continue contributing to the Forest Buffer Account in future years as quantified in section 95983(a)(1).

(e) Disposition of Forest Sequestration Projects After an Intentional Reversal.

(1) If ARB determines that an intentional reversal has occurred pursuant to section 95983(c), the forest offset project will automatically be terminated by ARB or an Offset Project Registry.

(2) New offset projects may not be initiated within the same offset project boundary if the forest offset project is terminated due to an intentional reversal.

(3) Offset credits issued to an offset project that suffers an intentional reversal may be determined to be invalid pursuant to section 95985.

§ 95984. Ownership and Transferability of Offset Credits Issued by ARB.

Initial ownership of an offset credit will be with the registered Offset Project Operator, Authorized Project Designee, or another third party as provided in section 95974(a)(1) unless otherwise required by section 95983. An offset credit issued by ARB may be sold, traded, or transferred, unless:

(a) the offset credit has been retired or surrendered for compliance in any voluntary or regulatory program;

(b) it resides in the Forest Buffer Account pursuant to section 95983; or

(c) it has been invalidated pursuant to section 95985.

§ 95985. Invalidation of Offset Credits.

(a) An offset credit issued by ARB under this Article will remain valid:

(1) until the offset credit has been retired or surrendered for compliance in any voluntary or regulatory program; or

(2) unless invalidated pursuant to section 95985(b).

(b) An offset credit may be determined to be invalid for the following reasons:

(1) a finding pursuant to section 95983 that a reversal occurred in a forest sequestration project; or

(2) ARB has determined that errors by verifiers, verification bodies, Offset Project Operators, Authorized Project Designee, or others involved in producing the documentation used to support the issuance of offset credits are sufficient to warrant a reversal.

(c) If ARB determines that an offset credit it issued is invalid pursuant to this section:

(1) the offset credit will be cancelled and removed from any Holding or Compliance account or the ARB Forest Buffer Account;

(2) the current holder, user, or retiree of the offset credit will be notified at the time of ARB's determination; and

(3) any approved program for linkage pursuant to subarticle 12 will be notified of the invalidation at the time of ARB's determination.

(d) If an offset credit found to be invalid pursuant to this section, except as provided in section 95985(e) and (f), has been retired or surrendered for compliance in any voluntary or regulatory program, the user or retiree of that offset credit must replace each metric ton of CO_2e with another approved compliance instrument pursuant to subarticle 4, within 30 calendar days pursuant to this section. If the user or retiree does not

replace the invalid offset credit within 30 calendar days of the notice of invalidation, each outstanding offset credit will constitute a violation. If the user or retiree is no longer in business ARB will require the Offset Project Operator or Authorized Project Designee to replace the offset credits and will notify the Offset Project Operator or Authorized Project Designee that they must replace them. The Offset Project Operator or Authorized Project Designee must replace each metric ton of CO_2e with another approved compliance instrument pursuant to subarticle 4, within 30 calendar days of being notified by ARB. If the Offset Project Operator or Authorized Project Designee does not replace the invalid offset credit within 30 calendar days of being notified by ARB, each outstanding offset credit will constitute a violation.

(e) If an intentional reversal occurs from a forest offset project, the Offset Project Operator or Authorized Project Designee must replace each metric ton of CO_2e with another approved compliance instrument pursuant to subarticle 4, within 30 calendar days of being notified by ARB. If the Offset Project Operator or Authorized Project Designee does not replace the invalid offset credit within 30 calendar days of being notified by ARB, each outstanding offset credit will constitute a violation.

(f) If an unintentional reversal occurs from a forest offset project, ARB will retire offset credits in the amount of tons reversed from the Forest Buffer Account. All other invalidated offset credits must be replaced pursuant to section 95985(d).

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code.
Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

§ 95986. Executive Officer Approval Requirements for Offset Project Registries.

(a) The approval requirements specified in this subarticle apply to all Offset Project Registries that will operate to provide registry services under this article.

(b) The Executive Officer may approve Offset Project Registries that meet the requirements specified in this section.

(c) The Offset Project Registry must be registered with ARB and apply for a Holding Account pursuant to section 95830.

(1) Offset Project Registry Approval Application. To apply for approval as an Offset Project Registry, the applicant shall submit the following information to the Executive Officer.

(A) name of applicant;

(B) name of president or chief executive officer;

(C) list of all board members, if applicable;

(D) addresses of offices located in the United States;

(E) documentation that the applicant carries least fifty million U.S. dollars of liability insurance; and

(F) list of any judicial proceedings and administrative actions filed against the applicant within the previous five years, with a detailed explanation as to the nature of the proceedings.

(2) The applicant must submit, in writing, the procedures to screen and address internal conflicts of interest. The applicant must provide the following information to the Executive Officer:

(A) staff, management, and board member conflict of interest policy where there is clear criteria for what constitutes a conflict of interest. The policy must:

(i) identify specific activities and limits on monetary and non-monetary gifts staff, management, or board members must not conduct or accept to meet the Offset Project Registry's internal policies of conflict of interest policy; and

(ii) include a requirement for annual disclosure by each staff, management, or board member of all monetary or non-monetary gifts received for the previous calendar year;

(B) list of all service types provided by the applicant,

(C) the industrial sectors the applicant serves,

(D) locations where services are provided; and

(E) a detailed organizational chart that includes the applicant and any parent, subsidiary, and affiliate companies.

(3) The program has the following capabilities for registration and tracking of offset credits:

(A) a comprehensive registration requirement for all registry participants

(B) tracking ownership and transactions of all offset credits it issues at all times; and

(C) possesses a permanent repository of ownership information on all transactions involving all offset credits it issues from the time they are issued to the time they are retired, including prices and counter-parties.

(d) The applicant's primary business must be operating an Offset Project Registry for voluntary or regulatory purposes.

(4) The applicant may not act as an Offset Project Developer, Authorized Project Designee, or offset project consultant once approved as an Offset Project Registry.

(5) The applicant may not act as a verification body and provide verification services pursuant to section 95977 once approved as an Offset Project Registry.

(e) The Offset Project Registry must continue to maintain the liability insurance required in section 95986(c) while it provides registry services

to Offset Project Operators or Authorized Project Designees who are implementing offset projects.

(f) If any information submitted pursuant to sections 95986(c) through (e) changes after the approval of an Offset Project Registry, the Offset Project Registry must notify the Executive Officer within 30 calendar days and provide updated information consistent with that required in sections 95986(c) through (e).

(g) The Offset Project Registry must attest, in writing, to ARB as follows:

(1) "As the authorized representative for this Offset Project Registry, I understand that the Offset Project Registry is voluntarily participating in the California cap-and-trade program under title 17, article 5, and the Offset Project Registry is now subject to all regulatory requirements and enforcement mechanisms of this program";

(2) "All information generated and submitted to ARB by the Offset Project Registry related to an offset project that uses an ARB Compliance Offset Protocol will be true, accurate, and complete";

(3) "All information provided to ARB as part of an ARB audit of the Offset Project Registry will be true, accurate, and complete";

(4) "All registry services provided will be in accordance to the requirements of section 95987";

(5) "The Offset Project Registry is committed to participating in all ARB training related to ARB's compliance offset program or Compliance Offset Protocols"; and

(6) The authorized representative of the Offset Project Registry must attest in writing, to ARB: "I certify under penalty of perjury under the laws of California I have authority to represent the Offset Project Registry and all information provided as part of this application is true, accurate, and complete."

(h) The management staff at the Offset Project Registry must take ARB provided training on ARB's compliance offset program.

(i) ARB Approval.

(1) Within 60 calendar days of receiving an application for approval as an Offset Project Registry and completion by all management staff of the training required in section 95986(h), the Executive Officer will inform the applicant in writing either that the application is complete or that additional specific information is required to make the application complete.

(2) The applicant may be allowed to submit additional supporting documentation before a decision is made by the Executive Officer.

(3) Within 60 calendar days following completion of the application process, the Executive Officer shall approve an Offset Project Registry if evidence of qualification submitted by the applicant has been found to meet the requirements of sections 95986(c) and (d) and issue an Executive Order to that effect.

(4) The Executive Officer and the applicant may mutually agree, in writing, to longer time periods than those specified in subsections 95986(i)(1) and 95986(i)(3).

(5) The Executive Officer approval for an Offset Project Registry is valid for a period of five years, whereupon the applicant may re-apply. At the time of re-application, the Offset Project Registry must meet all of the requirements in section 95986(c) and must not have been subject to any enforcement action under this article.

(j) Modification, Suspension, and Revocation of an Executive Order Approving an Offset Project Registry. The Executive Officer may review, and for good cause, modify, suspend, or revoke an Executive Order providing approval to an Offset Project Registry.

(1) During revocation proceedings, the Offset Project Registry may not continue to provide registry services.

(2) Within five working days of suspension or revocation of approval, an Offset Project Registry must notify all Offset Project Operators or Authorized Project Designees for whom it is providing registry services, or has provided registry services within the past 12 months, of its suspension or revocation of approval.

(3) An Offset Project Operator or Authorized Project Designee who has been notified by an Offset Project Registry of a suspended or revoked approval must re-submit its project information with a new Offset Project Registry or ARB.

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code.
Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

§ 95987. Offset Project Registry Requirements.

(a) The Offset Project Registry shall use Compliance Offset Protocols approved pursuant to section 95971 to determine whether an offset project may be listed with the Offset Project Registry for potential issuance of ARB offset credits.

(b) The Offset Project Registry must make the following information publicly available for each offset project:

(1) within 10 working days of the offset project listing requirements being deemed complete in section 95975(d):

(A) offset project name;

(B) offset project location;

(C) Offset Project Operator and, if applicable, the Authorized Project Designee;

(D) type of offset project;

(E) name and date of the Compliance Offset Protocol used by the offset project;

(F) date of offset project listing submittal and Offset Project Commencement date; and

(G) identification if the offset project is an Initial or renewed crediting period;

(2) within 10 working days of the Offset Project Data Report being issued an Offset Verification Statement:

(A) annual project baseline emissions;

(B) annual GHG reductions or GHG removal enhancements achieved by the offset project;

(C) the unique serial numbers of offset credits issued by the Offset Project Registry to the offset project;

(D) total, by calendar year, of verified GHG reductions or GHG removal enhancements for the offset project; and

(E) Offset Verification Statement for each year the Offset Project Data Report was verified; and

(3) clear identification of which offset projects are listed and submitting Offset Project Data Reports using Compliance Offset Protocols.

(c) Conflict of Interest Review by Offset Project Registries. The Offset Project Registry must apply the conflict of interest requirements in section 95979 when making a conflict of interest determination for a verification body proposing to conduct verification services under section 95977. The Offset Project Registry must review and make sure the conflict of interest submittal in section 95979(e) is complete. When an Offset Project Operator submits its information pursuant to section 95981(d) to ARB, the Offset Project Registry must provide ARB with the information and attestation identified in section 95979(e).

(d) The Offset Project Registry may provide guidance to Offset Project Operators, Authorized Project Designees, or offset verifiers for offset projects using a Compliance Offset Protocol, if there is no clear requirement for the topic in an ARB Compliance Offset Protocol, this article, or an ARB guidance document.

(1) An Offset Project Registry must maintain all correspondence and records of communication with an Offset Project Operator, Authorized Project Designee, or offset verifier when providing clarifications or guidance for an offset project using a Compliance Offset Protocol.

(2) Before providing such guidance, the Offset Project Registry may request ARB to provide clarification on the topic.

(3) Any Offset Project Operator or Authorized Project Designee requests for clarifications or guidance must be documented and the Offset Project Registry response must be submitted on an ongoing monthly basis to ARB beginning with the date of approval as an Offset Project Registry.

(e) The Offset Project Registry must audit at least 20% of the annual verifications of its offset projects developed using a Compliance Offset protocol.

(1) The audit must include the following checks:

(A) attendance with the offset verification team on the offset project site visit;

(B) in-person or conference call attendance for the first offset verification team and Offset Project Operator or Authorized Project Designee meeting;

(C) in-person or conference call attendance to the last meeting or discussion between the verification team and Offset Project Operator or Authorized Project Designee;

(D) documentation of any findings during the audit that lead to the Offset Project Registry to provide guidance or require corrective action with the verification team, including a list of issues noted during the audit and how those were resolved;

(E) a review of the detailed verification report and sampling plan to ensure that it meets the minimum requirements in section 95977 and documentation of any discrepancies found during the review; and

(F) an investigative review of the conflict of interest assessment provided by the verification body, which includes the following:

(i) discussions with both the lead verifier who submitted the conflict of interest assessment form and the Offset Project Registry or Authorized Project Designee to confirm the information on the conflict of interest assessment form is true, accurate, and complete;

(ii) an Internet-based search to ascertain the existence of any previous relationship between the verification body and the Offset Project Operator or Authorized Project Designee, and if so the nature and extent; and

(iii) any other follow up by the Offset Project Registry to have reasonable assurance that the information provided on the conflict of interest assessment form is true, accurate, and complete.

(2) All information related to audits of offset projects developed using a Compliance Offset Protocol must be provided to ARB within 10 days of an ARB request.

(3) The audits must be selected to provide a representative sampling of geographic locations of all offset projects, representative sampling of verification bodies, representative sampling of lead verifiers,

representative sampling of offset project types, and representative sampling of offset projects by size.

(4) The Offset Project Registry must provide an annual report to ARB by January 31 for its previous year's audit program of offset projects developed using Compliance Offset Protocols that includes:

(A) a list of all offset projects audited;

(B) locations of all offset projects audited;

(C) verification bodies associated with each offset project and names of offset verification team members;

(D) dates of site visits;

(E) Offset Project Registry staff that conducted the audit; and

(F) audit findings as required in section 95987(e)(1)(D) through (E).

(f) The Offset Project Registry must provide all information in its possession, custody, or control related to a listed offset project within 10 days of request by ARB.

(g) The Offset Project Registry must make its staff and all information related to listed offset projects by the Offset Project Registry available to ARB during any audits or oversight activities initiated by ARB to ensure the requirements listed in section 95987 are being carried out as required by this article.

(h) The Offset Project Registry must retire any offset credits issued for a project using a Compliance Offset Protocol once notified by ARB that the offset credits are eligible to be issued by ARB.

(i) The Offset Project Registry must provide an annual report by January 31 of the previous year's offset projects that are at least listed using a Compliance Offset Protocol. The report must contain the name of the offset project, type of offset project and applicable Compliance Offset Protocol, name of Offset Project Operator or Authorized Project Designee, location of project, status of offset project, associated verification body,

crediting period, amount of any credits issued to date, amount of any credits retired for the offset project by the Offset Project Registry to date.

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code.
Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

§95988. Record Retention Requirements for Offset Project Registries.

All information submitted and correspondence related to listed offset projects by the Offset Project Registry must be maintained by the Offset Project Registry for five years after the end of the crediting period for non-sequestration offset projects or, for sequestration offset projects the length of time that the offset project is issued offset credits by the Offset Project Registry plus 100 years.

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code.
Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

Subarticle 14: Recognition of Compliance Instruments from Other Programs

§ 95990. Recognition of Offset Credits for Early Action.

(a) ARB shall accept offset credits from offset projects registered with third-party offset programs approved pursuant to section 95990(c) if the offset credits meet the criteria set forth in this section.

(b) Criteria for Approval of Offset Credits Issued by Third Parties. An offset credit may be used to meet a compliance obligation under this article if the offset credit results from a GHG reduction or GHG removal enhancement which:

(1) occurred between January 1, 2005, and December 31, 2014;

(2) is verified pursuant to section 95990(f);

(3) results from an offset project with an offset project commencement date prior to January 1, 2012;

(4) results from an offset project located in the United States; and

(5) results from the use of one of the following offset quantification methodologies:

(A) Climate Action Reserve Livestock Protocol versions 1.0 through 3.0;

(B) Climate Action Reserve Urban Forest Protocol versions 1.0 through 1.1;

(C) Climate Action Reserve Ozone Depleting Substances Protocol version 1.0; and

(D) Climate Action Reserve Forest Protocol version 2.1; or

(E) Climate Action Reserve Forest Protocol versions 3.0 through 3.2, if the offset project meets the following requirements for ensuring permanence:

(i) conservation easement; or

(ii) contribution of offset credits based on the reversal risk of the offset project to an insurance buffer account.

(c) Approval of Third-Party Offset Programs for Purposes of Accepting Offset Credits for Early Action. To qualify as a third-party offset program for purposes of accepting offset credits for early action, the program must be issued an Executive Order pursuant to section 95986(d); or meet the following requirements:

(1) The program must provide documentation that it carries at least two million U.S. dollars of liability insurance.

(2) The program has the following capabilities for registration and tracking of offset credits:

(A) a comprehensive registration requirement for all registry participants;

(B) tracking ownership and transactions of all offset credits it issues at all times; and

(C) a permanent repository of ownership information on all transactions involving all offset credits it issues from the time they are issued to the time they are retired, including prices and counter-parties.

(3) The program's primary business is operating an offset project registry for voluntary or regulatory purposes.

(4) The program must agree to submit any available original documentation submitted by an Offset Project Operator or third-party verifier regarding the offset project, including registration documentation, sampling plans, and verification reports.

(5) The program must agree to retire and disqualify any offset credits it issues when retired or used in any voluntary or regulatory program, including when they are retired or approved for use in the California Cap-and-Trade Program.

(6) An authorized representative of the third-party offset program must attest in writing, to ARB, as follows:
"I certify under penalty and perjury of the laws of California the information provided in demonstrating this program meets the requirements in Section 95990(c) and is true, accurate, and complete."
"Upon acceptance of any offset credits for early action purposes, this program will meet the requirements in section 95990(c)(5)."

(d) Registration of Offset Credits Issued by Third Parties. Once an offset credit that is issued by an approved third-party offset program is determined by ARB to meet the criteria set forth in section 95990(b), ARB will assign an ARB serial number to the offset credit. Both the approved third-party offset program and ARB shall maintain the serial numbers of the offset credits it issues in perpetuity and track the transactions of offset credits until ARB retires it, at which time ARB will notify the approved third-party offset program to simultaneously retire it.

(e) Ineligible Offset Credits Issued by Third Parties. This section does not apply to an offset credit issued by an approved third-party offset program that has been retired, canceled, or used to meet a voluntary commitment or a surrender obligation in any voluntary or regulatory system.

(f) Regulatory Verification of Offset Credits for Early Action. Any offset credits issued by an approved third-party offset program that meet the requirements in section 95990(b) must be verified under the following requirements to be used to meet a compliance obligation under this article:

(1) The project must be verified by an ARB-accredited verification body that meets the accreditation requirements in section 95978.

(2) The verification body is subject to the conflict of interest requirements in section 95979. The potential for conflict of interest must be assessed against the Offset Project Developer for the project and any individuals or companies that currently hold the serialized offset credits for the project that will be submitted to be issued an ARB serialized offset credit. The conflict of interest submittal in section 95979 must be submitted to ARB.

(3) The verification body must conduct all of the offset verification services in section 95977 for the offset project and serialized offset credits that will potentially be issued ARB offset credits, for each offset data report for each year of the offset credits issued by the approved third-party offset program.

(A) If the offset project is still in operation, the verification body must conduct a site visit as required in section 95977(e)(2)(C)(iv).

(B) If the offset project is no longer in operation, the verification body will conduct a desk review of any available original documentation to confirm any previous verification findings

related to the types of verification services required in section 95977(e)(2)(C)(iv).

(i) The Offset Project Operator or the approved third-party offset program must provide the verification report(s) for the offset project to the ARB verifier to assist in the verification and desk review.

(ii) The Offset Project Operator must provide any original documentation to assist the verification body in its desk review.

(C) The sampling plan in section 95977(e)(2)(C)(vii) must cover all serialized offset credits issued by the approved third-party offset program that may potentially be issued an ARB offset credit;

(D) The data checks in section 95977(e)(2)(C)(xii) must include checks across the sources identified in the sampling plan, covering all years of the serialized offset credits issued by the approved third-party offset program that may potentially be issued an ARB offset credit;

(E) The verification body must submit an offset verification statement to ARB covering the serialized offset credits issued by the approved third-party offset program for the offset project that may potentially be issued an ARB offset credit;

(F) Only serialized offset credits issued by an approved third-party offset program that are within the scope of the offset verification services for an offset project and have received a positive offset or qualified positive offset verification statement are eligible to be issued an ARB offset credit.

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code.
Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

§ 95991. Sector-Based Offset Credits.

Sector-based offset credits may be generated through reduced or avoided GHG emissions from within, or carbon removed and sequestered from the atmosphere by, a specific sector in a particular jurisdiction. The Board may consider for acceptance compliance instruments issued from sector-based offset crediting programs that meet the requirements set forth in section 95994 and originate from developing countries or from subnational jurisdictions within those developing countries, except as specified in subarticle 13.

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code.
Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

§ 95992. Procedures for Approval of Sector-Based Crediting Programs.

The Board may approve a sector-based crediting program in an eligible jurisdiction after public notice and opportunity for public comment in accordance with the Administrative Procedure Act (Government Code section 11340 et seq.). Provisions set forth in this article shall specify which compliance instruments issued by an approved sector-based crediting program may be used to meet a compliance obligation under this Article.

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code.
Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

§ 95993. Sources for Sector-Based Offset Credits.

Sector-based credits may be generated from:

(a) Reducing Emissions from Deforestation and Forest Degradation (REDD) Plans; and

(b) Reserved for other sources of sector-based credits.

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code.
Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

§ 95994. Requirements for Sector-Based Offset Crediting Programs.

(a) General Requirements for Sector-Based Crediting Programs. The Board may consider for approval a sector-based crediting program which may include the following sectoral requirements:

(1) Sector Plan. The host jurisdiction has established a plan for reducing emissions from the sector.

(2) Monitoring, Reporting, Verification, and Enforcement. The program includes a transparent system that regularly monitors, inventories, reports, verifies, and maintains accounting for emission reductions across the program's entire sector, as well as maintains enforcement capability over its reference activity producing credits.

(3) Offset Criteria. The program has requirements to ensure that offset credits generated by the program are real, additional, quantifiable, permanent, verifiable and enforceable.

(4) Sectoral Level Performance. The program includes a transparent system for determining and reporting when it meets or exceeds its crediting baseline(s), and evaluating the performance of the program's sector during each program's crediting period relative to the business as usual or other emissions reference level.

(5) Public Participation and Participatory Management Mechanism. The program has established a means for public participation and consultation in the program design process.

(6) Nested Approach. If applicable, the program includes:

(A) Offset project-specific requirements that establish methods to inventory, quantify, monitor, verify, enforce, and account for all project-level activities

(B) a system for reconciling offset project-based GHG reductions in sector-level accounting from the host jurisdiction.

(b) Sector-Specific Requirements. Pursuant to section 95996, specific sectors may have specific requirements unique to that sector.

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code.
Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

§ 95995. Quantitative Usage Limit.

Sector-based offset credits approved by ARB for compliance pursuant to section 95821(d) are subject to the quantitative usage limit specified in section 95854.

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code.
Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

§ 95996. Reserved for Sector-Specific Requirements.

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code.
Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

§ 95997. Reserved for Approved Sector-Based Crediting Programs.

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code.

Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

Subarticle 15: Enforcement and Penalties

§ 96010. Jurisdiction.

Any of the following actions shall conclusively establish a person's consent to be subject to the jurisdiction of the State of California, including the administrative authority of ARB and the jurisdiction of the Superior Courts of the State of California:

(a) registration with ARB pursuant to subarticle 5;

(b) the purchase or holding of a compliance instrument issued by ARB;

(c) receipt of compensation of any kind, including sales proceeds and commissions, from any transfers of allowances or offset credits issued by ARB pursuant to subarticle 13 or recognized by ARB pursuant to subarticle 14; or

(d) verification of an offset credit to be issued by ARB.

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code.
Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

§ 96011. Authority to Suspend, Revoke, or Modify.

(a) The Executive Officer may suspend, revoke, or place restrictions on the Holding Account of a voluntarily associated entity determined to be in violation of any provision of this article.

(b) The Executive Officer may place restrictions on a Holding Account of a covered entity or an opt-in covered entity determined to be in violation of any provision of this article or of article 2 of this subchapter.

(c) The Executive Officer may suspend or revoke the registration for an entity registered pursuant to 95814(b).

(d) The Executive Officer may suspend, revoke, or modify any Executive Order issued under this article or under article 2 of this subchapter, including an order accrediting a verifier, for a violation of any provision of this article.

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code.
Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

§ 96012. Injunctions.

Any violation of this article may be enjoined pursuant to Health and Safety Code section 41513.

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code.
Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

§ 96013. Penalties.

Penalties may be assessed pursuant to Health and Safety Code section 38580 for any violation of this article.

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code.
Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

§ 96014. Violations.

(a) If a covered entity fails to surrender a sufficient number of compliance instruments to meet its compliance obligation as specified in sections 95856 or 95857 there is a separate violation of this Article for each required compliance instrument that has not been surrendered.

(b) There is a separate violation for each day or portion thereof after the compliance date that each required compliance instrument has not been surrendered.

(c) Each day or portion thereof in which any other violation of this Article occurs is a separate offense.

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code.
Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

Subarticle 16: Other Provisions

§ 96020. Severability, Effect of Judicial Order.

Each provision of this article shall be deemed severable, and in the event that any provision of this article is held to be invalid, the remainder of this article shall continue in full force and effect.

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code.
Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

§ 96021. Confidentiality.

(a) Emissions data submitted to ARB under this article is public information and shall not be designated as confidential.

(b) Any entity submitting information to the Executive Officer pursuant to this subarticle may claim such information as "confidential" by clearly identifying such information as "confidential." Any claim of confidentiality by an entity submitting information must be based on the entity's belief that the information marked as confidential is either trade secret or otherwise exempt from public disclosure under the California Public Record Act (Government Code, section 6250 et seq.). All such requests for confidentiality shall be

handled in accordance with the procedures specified in California Code of Regulations, title 17, sections 91000 to 91022.

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code.
Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

§ 96022. Reserved Provisions.

[Placeholder]: Provisions to be developed.

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code.
Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

State of California

California Environmental Protection Agency
AIR RESOURCES BOARD
Office of Climate Change

STAFF REPORT: INITIAL STATEMENT OF REASONS PROPOSED REGULATION TO IMPLEMENT THE CALIFORNIA CAP-AND-TRADE PROGRAM

PART II

STAFF REPORT AND COMPLIANCE OFFSET PROTOCOL

URBAN FOREST PROJECTS

Public Hearing to Consider the Proposed Regulation to Implement the California Cap-and-Trade Program

Date of Release: October 28, 2010
Scheduled for Consideration: December 16, 2010

Location:

California Air Resources Board
Byron Sher Auditorium
1001 I Street
Sacramento, California 95814

This report has been reviewed by the staff of the California Air Resources Board and approved for publication. Approval does not signify that the contents necessarily reflect the views and policies of the Air Resources Board, nor does mention of trade names or commercial products constitute endorsement or recommendation for use.

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Compliance Offset Protocol for Urban Forest Projects
Date: October 13, 2010

Staff Report

I. Introduction and Background on Compliance Offset Protocols

A. Staff Proposal

Staff is recommending the Board adopt four compliance offset protocols to support the proposed Cap-and-Trade program. They include a compliance offset protocol for Livestock Manure (digester) projects, Ozone Depleting Substances destruction projects, Urban Forest projects, and Forest Projects. This part discusses the development of a compliance offset protocol for Urban Forest projects.

B. Rationale for Compliance Offset Protocols

The Air Resources Board's (ARB or Board) proposed cap-and-trade program allows the use of offsets, emission reductions from uncapped sectors, to comply with emission reduction obligations. Offset credits are issued from projects developed using ARB-adopted compliance offset protocols. Compliance offset protocols contain the project eligibility criteria to ensure reductions are additional, quantification methodologies and regulatory verification and enforcement requirements, as required by AB32. Therefore, they represent the standard by which offset projects are reviewed and judged. They contain the basic methods and procedures to conduct the offset project and determine the greenhouse gas reduction benefits. AB 32 also requires that offsets be "real, permanent, quantifiable, verifiable, enforceable, and additional."

C. ARB Transition to Compliance Offset Protocol

In order to encourage early actions to reduce greenhouse gas (GHG) emissions, the Board decided to adopt GHG emission reduction project protocols starting in 2007. In October 2007, the Board adopted its first Forest Project Protocol, version 2.1 developed by the Climate Action Reserve (CAR). In September 2008, the Board adopted the Livestock Manure Project Protocol version 2.1 and Urban Forest Protocol version 1.0, also for early action projects. Finally in September 2009, the Board adopted the Forest Project Protocol version 3.0, an update to version 2.1 to enable greater participation in forest projects. The Ozone Depleting Substances Project Protocol version 1.0 was adopted by CAR in early February 2010, and the timing precluded it from being adopted by the Board.

The adoption of the protocols represented the Board's endorsement of technically sound approaches for carbon accounting for early action projects. Each of these protocols were developed by CAR and taken through an ARB public review process before they were adopted by the Board.

At its February 2010 meeting, the Board requested staff to initiate a public process to transition the protocols for use as compliance offset protocols for compliance purposes in the proposed cap-and-trade program. The Board rescinded approval of the early action protocols in order to begin the transition to a regulatory compliance offset program. Staff began the process by reviewing updates made to the early action protocols since the Board adopted them. On June 23, 2010, ARB staff held a public workshop to discuss the four protocols that were under consideration for modification to align with criteria in AB 32 and the proposed cap-and-trade rule.

D. Compliance Offset Protocol Structure and Regulatory Requirements

Protocols consist of two main structural elements, project requirements and project quantification. Project requirements include items such as eligibility, monitoring and reporting, and verification and enforcement provisions. AB 32 requires ARB to adopt regulatory requirements for verification and enforcement of any offset reductions used for compliance purposes. Project quantification identification with the quantification methodologies and equations used in project accounting such as baseline determination and calculation of emissions and emission reductions.

Compliance offset protocols will be incorporated by reference into the proposed cap-and-trade regulation. This incorporation makes the offset protocol document an enforceable regulation. AB 32 exempts quantification methodologies from the Administrative Procedure Act (APA), however those elements of the protocol are still regulatory, The exemption allows future updates to the quantification methodologies to be made through a public review and Board adoption process but without the need for rulemaking documents. Each protocol identifies sections that are considered quantification and exempt from APA requirements. Any changes to the non-quantification elements of the offset protocols would be considered a regulatory update subject to the full regulatory development process.

Since the protocols will now be used in the context of a compliance program, staff has modified language in the protocols to refer to the regulatory requirements in the proposed cap-and-trade regulation where needed rather than splitting the protocols into separate documents based on regulatory requirements and quantification methodologies. In sections where there is a regulatory requirement in the cap-and-trade regulation, staff refers readers to the regulation.

In addition, the proposed cap-and-trade rule includes offset program regulatory requirements, including but not limited to, eligibility criteria for start dates, project locations, offset project reporting periods, project document retention, project listing information, project reporting information, verification requirements, permanence mechanisms for sequestration projects, and enforcement provisions. Where there are regulatory requirements in the cap-and-trade rule, staff has modified language in the protocol to align with the rule.

E. Environmental Impacts

The California Environmental Quality Act (CEQA) and ARB policy require an analysis to determine any potentially adverse environmental impacts of any potential projects under the compliance offset program. ARB determined that adoption and implementation of the proposed compliance offset protocols constitute "projects" as defined by Public Resources Code §21000 et seq. The CEQA Guidelines, §15378 provides the definition of a project. ARB has included a tiered environmental review of the proposed cap-and-trade regulation, the offset program, and subsequently adopted compliance offset protocols in the cap-and-trade regulation.

II. Compliance Offset Urban Forest Project Protocol

A. Role of Urban Forests in Climate Change Mitigation

Urban forestry is the professional management of urban tree populations by local governments and agencies, public institutions, utilities, and non-governmental organizations for the purpose of improving the urban environment. As long as trees are growing, they remove CO2 from the air in a process called carbon sequestration, transforming CO2 into carbon and making use of it to build living matter—leaves, stems, trunk, roots. Urban forests absorb atmospheric CO2 and store carbon in woody biomass, and have the potential to provide greenhouse gas (GHG) reductions when managed for climate benefits. A climate protection role for urban forests has been recognized by the Climate Action Team (CAT 2007) and by ARB's AB 32 implementation Scoping Plan, where urban forestry is one of five strategies to enhance the capacity for urban and rural forests to remove atmospheric CO2.

B. Development of the Urban Forest Compliance Offset Protocol

Version 1.0 of the Climate Action Reserve's (CAR) Urban Forest Project Protocol was developed over a two year stakeholder process which began in September 2006. CAR assembled a 19 member Steering Committee comprised of representatives from CAL FIRE, the USDA Forest Service, the California Energy Commission, the Sacramento Municipal Utility District, ARB, three non-governmental organizations, and a professional arborist. A twenty-five

member Technical Committee comprised of subject-matter experts in urban forestry, forest biometrics, and carbon sequestration provided peer review of methods and the final documents.

CAR and ARB staff solicited comment on the draft protocol through email, correspondence, telephone, and a public workshop on July 29, 2008 at CAL EPA headquarters. On September 29, 2008, ARB formally adopted version 1.0 of the urban forest project protocol as a means to encourage early action projects to reduce GHGs. In February 2010, the Board requested ARB staff to transition the early action protocol to a compliance offset protocol for compliance purposes in the proposed cap-and-trade program.

Version 1.1 of the protocol was adopted by CAR on March 10, 2010. Version 1.1 incorporates updates to project start date, a supplemental method for quantifying vehicle and equipment fossil fuel combustion GHG emissions when entities lack fuel and equipment use data, clarifying language on reporting schedules, and an update to verification schedules.

Staff presented the Urban Forest project protocol at a June 23, 2010, workshop to introduce the protocol to stakeholders and address any questions or concerns at that time. Stakeholders were provided an opportunity to provide feedback on the staff's presentation and proposal for moving ahead with the Urban Forest project protocol.

C. Description of the Compliance Offset Urban Forest Protocol

Overview

ARB's proposed Compliance Offset Urban Forest Project Protocol is based on version 1.1 of the Climate Action Reserve's Urban Forest Project Protocol. For this compliance offset protocol, the GHG reduction project is a planned set of tree planting and maintenance activities in urban areas along streets, in parks, on educational campuses, and in utility service areas, to enhance atmospheric CO2 removal and permanently increase carbon storage.

To fit into a statewide, national, and international GHG accounting framework, urban forest project accounting must meet recognized and robust standards including the requirements of AB 32. This requires that GHG reductions be real, additional, independently verified, not double-counted, and permanent. The offset protocol is designed to meet these standards and requirements and provide accurate and standardized GHG accounting methods for complete, consistent, transparent, accurate, and conservative accounting GHG emissions and emission reductions associated with urban forest projects. The offset protocol also defines eligibility rules, offset project boundaries, provides GHG

reduction and emission calculation methods, and identifies procedures for project monitoring, reporting parameters, and verification. All projects that pass the eligibility requirements set forth in this offset protocol and the cap-and-trade regulation are eligible to register GHG reductions for the duration of the project-crediting period, which is twenty-five years with an option to renew.

Additionality

Eligible projects under this offset protocol must result in reductions that are additional to what would have occurred in the absence of the project. The offset protocol ensures additionality utilizing a performance standard approach and a regulatory additionality requirement.

The performance standard is an identified standard of performance applicable to urban forest projects undertaken by municipalities, educational campuses, and utilities. The purpose of a performance standard is to establish a threshold that is significantly better than average GHG production for a specified activity, which, if met or exceeded by a project developer, satisfies the criterion of "additionality." If the project meets the threshold, then it exceeds what would happen under the business-as-usual scenario and generates surplus/additional GHG reductions.

For the Urban Forest Project Offset Protocol, projects must exceed "business as usual" performance standard thresholds established for municipalities, educational campuses, and utilities. The performance standards are defined by Net Tree Gain calculations, which is the difference between the number of trees planted minus number of trees removed due to disease, mortality or disturbance. A Net Tree Gain of zero represents maintenance of a stable urban tree population.

In addition to the performance standard, eligible projects must show regulatory additionality, meaning that there are no state or federal regulations or local agency ordinances/rulings or other mandates requiring the planting of project trees.

Permanence

Three requirements help ensure that atmospheric CO2 removed by urban trees is permanently stored as carbon. First, project tree carbon stocks must be reported annually for 100 years. Second, projects must replace dead project trees and lost planting sites. Third, failure to compensate lost tree carbon for which offset credits have been issued, with replacement trees, is considered a reversal.

Quantification Methodologies

The offset protocol includes quantification of atmospheric CO2 removal and carbon storage by tree carbon stock change, and CO2 emissions by vehicles and equipment used in project tree maintenance. Project GHG reduction is calculated as the difference between atmospheric CO2 removal and carbon sequestration by project trees and CO2 emissions by project vehicles and equipment. Staff believes the quantification methods in version 1.1 of the offset protocol are robust, as urban tree structure and function are well understood. The offset protocol contains requirements for urban tree inventory, monitoring, measurement, and levels of accuracy. For cases where sampling may be performed rather than census, procedures for determining statistical confidence in estimates of project tree population carbon stocks are provided. Methods for estimating CO2 emissions from project vehicle and equipment fossil fuel combustion are based on USEPA and ARB emission factors.

The offset protocol uses equations approved by the USDA Forest Service, Center for Urban Forest Research to estimate urban tree volume, biomass, and carbon content from tree measurements. These are published in the offset protocol and can be implemented by hand or in spreadsheet software. Equations for estimating CO2 emissions from fossil fuel combustion by project vehicles and equipment are based on USEPA methods and the compliance offset version of the offset protocol incorporates updated fuel emission factors.

Monitoring, Reporting and Verification

Project developers are responsible for monitoring performance of the project and reporting project monitoring data. Project monitoring data reported annually include project and non-project tree planting, removal, expenditures, vehicle and equipment fuel use and CO2 emissions, and project tree species, location, dimension, volume, biomass, and carbon stocks. Project developers must submit verified reports of project tree carbon stock change, and project GHG reductions resulting from project activity at least once every six years. For transparency, project information will be made publically available.

III. Specific Changes made to CAR's Urban Forest Project Protocol

Staff has included three content changes. Because only verifiable GHG reductions may qualify for offset credit, staff has removed quantification and reporting of non-creditable indirect GHG reductions attributed to building energy use and fossil fuel displacement. Staff removed carbon stock quantification based on urban tree growth modeling, based on the fact that urban tree growth models are provided in CAR's protocol as "proof of concept" shareware which have not been peer reviewed or published. As a result, in the compliance offset protocol, project tree carbon is quantified and verified from measurements gathered during periodic censuses or from sampling. Developers of urban forest projects are required to monitor carbon stocks for which offset credits have been

issued for a hundred years and held accountable for any reversals of project offset credits.

Broadly, the types of changes made to transition the CAR Protocol to an ARB compliance offset protocol included:

- Aligning and clarifying terminology to match ARB regulations, such as project developer versus operator, CRTs versus offset credits, project start date versus project commencement, etc.
- Aligning requirements such as listing and reporting requirements to match Cap and Trade regulations
- Requiring ARB's regulatory verification program for accreditation of verification bodies, verification services, conflict of interest, etc.

The following list provides specific changes made to transition CAR's protocol to an ARB compliance offset protocol:

- Referenced to CAR protocol and removed all other references;
- Removed references specific to CAR and their process, including references to CRT's, CAR attestation forms that ARB does not need to implement the offset protocol, verification requirements, and process for starting a project.
- Some text was removed and replaced with references to the regulatory language. This includes language on the legal requirement test, the performance standard test, and the project documentation section;
- Modified terminology to be consistent with the regulation.
    - Project developers are now offset project operators or authorized project designees;
    - Project start date changed to project commencement;
    - Project Monitoring and Operation changed to Project Documentation;
    - Record Keeping Section and changed to Document Retention;
    - Updated glossary to reflect regulatory definitions.
- Aligned start date eligibility with ARB regulation and changed project commencement information to be in line with ARB's regulatory process;
- Changed the Reporting period and verification cycle to align with regulation;
- Changed 12 month reporting period for a project to a single calendar year;
- Included annual reporting requirements, project data report requirements and record retention requirements;
- Project listing requirements replaced the project submittal form;
- Changed verification to be in line with regulation and removed language on project developer disclosure of non-compliance to verifier;
- Removed text on non-compliance due to "acts of nature"
- Removed text that was unrelated or unnecessary for project quantification, or implementation.
- Removed language on non-creditable co-benefits and indirect GHG reductions attributed to building energy use, tree residues used as biofuel.

- Entity was replaced with "municipality", "educational campus" or "utility" where applicable.
- Performance Standard Test modified to emphasize the Net Tree Gain metric.
- Modified the Project GHG Reduction equation from an annual estimate to a crediting-period basis, which can be multi-year for sequestration projects.
- Removed option to estimate tree carbon stocks based on growth modeling, including Appendix D and references in Appendix C.
- Required monitoring of credited carbon stocks to be monitored for 100 years.
- Corrected sampling error equation in Section 6.1.2 (Requirements for Tree Monitoring and Acceptable Levels of Uncertainty)
- Removed placeholder language on remote sensing approaches to urban forest inventory and urban forest carbon stock estimation which are still in development and have not yet been peer reviewed.
- Updated fuel CO2 emission factors
- Project documentation for verification: inserted explicit requirements to document fuel consumption and vehicle/equipment CO2 emission calculations, carbon stock, stock-change, and CO2 tonnage calculations, project GHG reduction calculations.
- Some requirements specific to urban forestry verification concerning reconciling results from desk verification and site visit verification, and have been removed with the elimination of desk verification.

IV. References

CAR (2010) Urban Forestry Project Protocol Version 1.1. March 10, 2010. http://www.climateactionreserve.org/how/protocols/adopted/urban-forest/current-urban-forest-project-protocol/ (accessed August 30, 2010)

California Environmental Protection Agency

AIR RESOURCES BOARD

Compliance Offset Protocol for Urban Forest Projects

Adopted: [INSERT Date of Board Adoption]

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maintenance. In such situations, stratified random sampling will be the most efficient and meaningful method for selecting samples. In this method, the population to be sampled is first divided into meaningful subunits or strata. These may be large subdivisions, planning sectors, maintenance districts, or any other convenient management or planning unit.

If strata are assigned so that each is more or less homogeneous with respect to the characters being measured, fewer samples will be needed to adequately characterize each stratum. For instance, if tree cover is to be assessed in different portions of a city, visual estimates of the tree canopy cover could be used to help demarcate zones where canopy cover is relatively uniform. A sample of street trees might be stratified by tree species, size, and/or age, depending on the purpose of the evaluation. If these trees were classified in a municipal street tree database, stratification might be accomplished relatively simply from existing tree data. However, if such data are lacking, it may be necessary to conduct a preliminary sample to delineate the population before sampling occurs.

Once strata are assigned and delineated, samples are drawn at random from within each stratum. If the number of samples selected from each stratum is not proportional to the size of the stratum, the averages from each will have to be weighted to obtain an overall population average. Given prior knowledge about the population, stratified sampling is a commonly used probability method that is superior to random sampling because it reduces error.

A.3.5 Sampling Size

Optimal sample size will vary somewhat with the characteristics being rated or tallied.

In general:

- Up to a point, the reliability of estimates will increase as sample size increases
- The more variable the population is with respect to the characteristic(s) being rated, the larger the sample should be
- A large sample is required to accurately estimate the frequencies of relatively rare events or characteristics
- Larger sample sizes are needed to detect relatively small differences between means or proportions; smaller sample sizes may suffice if the differences are relatively large

The optimum sample size represents a compromise between cost and accuracy, since both generally increase with increasing sample size. An optimum sample size can be determined by identifying the point of diminishing returns beyond which further increases in accuracy are not worth the additional costs of data collection. Optimum sample size will vary with the type of data being collected, so it is not possible to set a single number for all applications.

However, certain statistical formulas can be used to estimate the minimum sample size needed for a specific purpose. A number of statistics web sites include on-line interactive calculators that allow required sample sizes to be estimated. Before these sample size calculators can be used, several things must be known about the data that will be collected and how it will be analyzed.

Type of Data

Main types include:

1. Continuous – variables can take any value, e.g. tree diameters
2. Discrete – variables can only have certain discrete values
    a. Types of discrete data include:

A.3.2 Random Sampling and Random Numbers

Most statistical methods used in environmental areas are based on the assumption of random sampling. This means that every unit in the population has an equal chance (or known probability) of being chosen for the sample. Furthermore, the selection of random units should be independent of other units that have been sampled. If a sample unit is rejected because it is too close to one already chosen, the sample will not be random and independent. A relatively simple and reliable method for randomization is to use random numbers. Most spreadsheet, database, and statistical programs have functions that generate random numbers. Random number generators can also be downloaded (e.g. http://www.buffalo.edu/~raulin/random.html or http://nhse.npac.syr.edu/roadmap/algorithms/random.html) or random numbers can be chosen from printed tables.

Several techniques can be used to draw a random sample from a population that consists of individual objects or records (e.g. street addresses or tree numbers). Many spreadsheet programs include tools that can produce a random sample of a specified size from a range of cells. Alternatively, a unique random number can be assigned to each unit or record, sorting the list based on the random number, and picking the required number of units from the top of the sorted database.

In some cases, it is necessary to take random samples across a geographic area, such as part or all of a city or forested area. In such a situation, random sample points can be assigned by randomly sampling from a coordinate grid that has been established for the area in question. This may either be an existing set of map-based coordinates, such as UTM or State Plane grids, or an arbitrary grid based on units measured on a map or aerial photograph (e.g. distances measured from the bottom and left edge of the map or photo). After the range of X and Y coordinates have been determined within the area to be sampled, X and Y coordinates can be selected randomly to generate random sample points. This is simple random sampling, one of five common random sampling techniques. The other four include systematic sampling, stratified sampling, cluster sampling, and multi-stage sampling. The i-Tree random sampling tool can be used to locate sample plots (http://itreetools.org/applications/sig.shtm).

A.3.3 Systematic Sampling

Systematic sampling means that the sample units are selected at equally spaced intervals over a population. Examples include selecting every tenth tree from a list of trees or selecting sample plots at equally spaced distances over a project area. In carefully planned forest surveys, systematic sampling can yield more precise results than simple random sampling. Systematic sampling is unbiased if the first unit is randomly selected. One advantage to systematic sampling is that it is simpler to select one random number and then collect data on every 5th, 10th or 15th (project developer chooses the interval) tree on the list, than to select as many random numbers as the sample size (although these numbers can be generated by any spreadsheet program). It also provides a good spread across a tree population. A disadvantage is that a list is needed to start with to be able to know total sample size and to calculate a sampling interval. The only advantage of systematic sampling over simple random sampling is the simplicity of needing to choose only one random number.

A.3.4 Stratified Sampling

In many urban forest applications, it is desirable to have samples distributed throughout the population. For instance, the project developer may want to ensure that trees from each of several different land use zones are included in the sample because it has been determined that trees are growing differently in different land use areas due to differences in care and

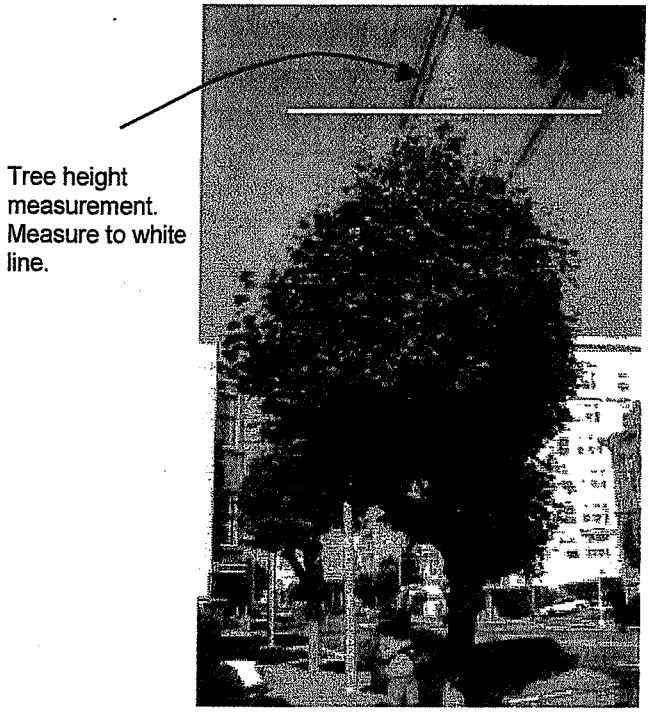

Figure A.2. Example of Tree with Erratic Leader

A.3 Sampling from Populations

As previously mentioned, sampling involves measuring only a portion of the trees on the project and using the data to estimate parameters of interest for the overall population. The following information is from CAR (2010).

A.3.1 Statistical Bias

The reason for using statistically sound sampling methods is to avoid bias in the estimates of the parameter(s) measured. Although the value of any single estimate (biased or not) is unlikely to equal the true population value, the mean of a large number of unbiased estimates will approximate the true value. In contrast, the mean of a large number of biased estimates will either be higher or lower than the true population value, depending on the direction of the bias. If the project developer is interested in knowing the actual value of a parameter from the population (e.g. actual tree dbh), they generally want to use an unbiased estimator of that parameter. In some situations, a small bias (e.g. a tendency to slightly over- or underestimate cover) can be tolerated if the bias is small relative to the standard deviation of the estimate (i.e. errors (perhaps 10% to 15% or less).

Bias in estimates can come from various sources. For instance, if tree shadows are counted as canopy in aerial photo interpretation (misclassification bias), the canopy cover estimate will be biased upward. Many types of bias can be avoided through good sampling design and the careful implementation of appropriate evaluation techniques.

$$DRC = SQRT [12.2^2 + 13.2^2 + 3.8^2 + 22.1^2]$$
$$= SQRT [825.93]$$
$$= 28.74$$
$$= 28.7$$

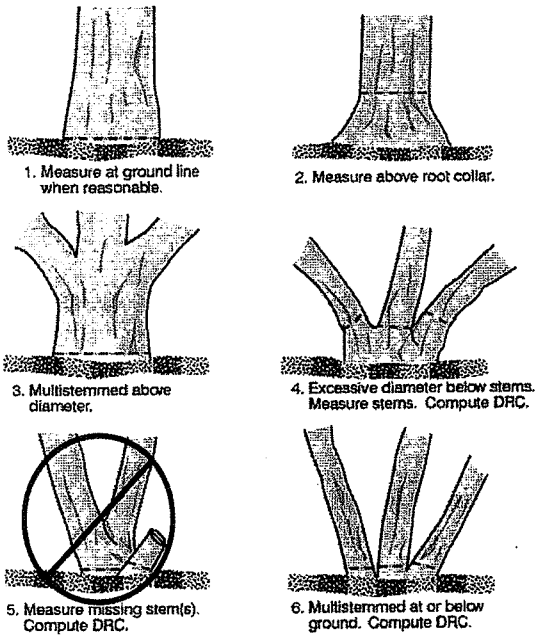

Figure A.1. Measuring DRC in Various Situations

Tree Height

From ground level to tree top to nearest 0.5 m (omit erratic leader as shown in Figure A.2) with range pole, altimeter or clinometer.

plus one number when genus and species letters are duplicated in study. Use species coding lists in i-Tree Manual 2.2 as guide. (Example: *Acer saccharum* = ACSA and *Acer saccharinum* (in same study) would be ACSA1).

Diameter at Breast Height (dbh in cm)

Measure the diameter at breast height (1.37m) to nearest 0.1 cm using a dbh tape (available from most forestry suppliers). Where possible for multi-stemmed trees forking below 1.37 m measure above the butt flare and below the point where the stem begins forking. When this is not possible, measure diameter at root collar (DRC) as described below. Saplings (dbh/DRC 2.54 - 12.5 cm) will be measured at 1.37 m unless falling under multi-stemmed/unusual stem categories requiring DRC measurements (per FHM Field Methods Guide [see reference in CAR 2010]).

Diameter at Root Collar (DRC in cm)

The method for measuring diameter at the root collar is adapted from the FHM Field Methods Guide. For species requiring diameter at the root collar, measure the diameter at the ground line or at the stem root collar, whichever is higher. For these trees, treat clumps of stems having a unified crown and common root stock as a single tree; examples include mesquite, juniper, and mountain mahogany. For multi-stemmed trees, compute and record a cumulative DRC (see below); record individual stem diameters and a stem status (live or dead) on a separate form or menu as required.

Measuring DRC: Before measuring DRC, remove the loose material on the ground (e.g. litter) but not mineral soil. Measure just above any swells present, and in a location so that the diameter measurements are reflective of the volume above the stems (especially when trees are extremely deformed at the base).

Stems must be at least 1.0 ft in length and 1.0 inch in diameter to qualify for measurement; stems that are missing due to cutting or damage must have previously been at least 1.0 ft in length (estimate by checking diameter of wound and compare with diameter and length of other stems – checking taper).

Whenever DRC is impossible or extremely difficult to measure with a diameter tape (e.g. due to thorns, extreme number of limbs), stems may be estimated and recorded to the nearest 1.0 inch class.

Additional instructions for DRC measurements are illustrated in Figure A.1. Do not measure cut stems as shown in Diagram 5 of Figure A.1; measure only complete stems.

Computing and Recording DRC: For all trees requiring DRC, with at least one stem 1.0 inch in diameter or larger at the root collar, DRC is computed as the square root of the sum of the squared stem diameters. For a single-stemmed DRC tree, the computed DRC is equal to the single diameter measured and rounded to the nearest 0.1 inch.

Use the following formula to compute DRC:

$$DRC = SQRT\,[SUM\,(\text{stem diameter}^2)]$$

For example, a multi-stemmed woodland tree with stems of 12.2, 13.2, 3.8, and 22.1 would be calculated as:

A.2.2 What to Record

For assessing and monitoring carbon stocks and energy emission reductions, any database associated with an inventory system must be capable of producing the reports required for project reporting. Table A.1 shows an example list of key data fields, drawn from i-Tree's STRATUM software developed by the USDA Forest Service as an inventory and reporting tool. More detailed components required for a STRATUM inventory are listed in the STRATUM users guide available at http://itreetools.org/resource_learning_center/elements/i-Tree_v12_UsersManual_Final.pdf. The manual also includes information on UFORE plot sampling methods based on the *Forest Inventory and Analysis (FIA) Field Core Methods Handbook* (see reference in CAR 2010).

Table A.1. Example of Common Data Fields for Tree Inventorying

Data Field	Description	Purpose
Tree Id	unique tree identifier	tree location
Zone	alphanumeric code/name showing management area or zone where tree is located	area/zone comparisons or sampling areas
Street Segment	numeric code used with STRATUM sampling program	used in sampling to predict population by dbh classes
City Managed	numeric code showing city or private tree ownership	asset value, structure
Species Code	alphanumeric code denoting genus and species	species and tree count,
Land Use	numeric code for landuse types (e.g., single family residential, commercial, park)	may assist in stratified sampling
Loc Site	numeric code for tree site (e.g., front lawn, planting strip, median, cutout)	tree location info, stratified sampling, energy benefits
DBH	numeric code for diameter-at-breast-height	growth, structure, age, carbon storage, annualization, costs
Mtce Recommendation	numeric code for recommended mtce (e.g., young tree, mature tree)	tree health,mortality, pruning needs assessments
Priority Task	numeric code for highest priority task to perform on tree	tree health,mortality, pruning needs assessments
Sidewalk Damage	numeric code describing extent of damage	costs, size and species associated with damage
Wire Conflict	numeric code describing utility line conflicts	costs, size and species associated with conflicts
Condition Wood	numeric code describing wood (structural) health of tree	asset value, structure
Condition Leaves	numeric code describing foliar (functional) health of tree	asset value, structure
OtherOne, Two, Three	numeric data field with up to 10 variables to be described by user	3 fields in STRATUM to be defined by user
Setback	distance between tree and nearest air-conditioned/heated space	energy analysis use/energy conservation projects
Tree Orient	numeric data listing 1 of 8 azimuth orientations of tree in reference to building	energy analysis use/energy conservation projects

Source: i-Tree STRATUM program.

Essentially, the data to be collected will depend upon the project needs. To estimate carbon stocks, information on tree species and 'diameter at breast height' (dbh) are the minimum requirements.

A.2.3 Measuring Method and Allowable Error for Primary Measurements

This section describes the minimum data collection fields and allowable measurement error necessary to report an urban forest GHG tree project.

Species

The most common method for identifying species in an inventory is the use of species code – usually a four-letter code taken from first two letters of genus and species names, or four letters

Service Northeastern Area State and Private Forestry website at http://www.na.fs.fed.us/urban/inforesources/inventory/InventorySoftwareListDetails.pdf. This list is an addendum to *A Guide to Street Tree Inventory Software* (see reference in CAR 2010) available at http://www.na.fs.fed.us/spfo/pubs/uf/streettree/toc.htm. This publication provides pertinent information on choosing an inventory system (Box B.1) including evaluation procedures and software comparisons. In addition, the *Best Management Practices Tree Inventories* companion guide to the *American National Standards Institute (ANSI) A300 Standards for Tree Care* series provides information on key components and data collection fields for urban tree inventories.

Box A.1. Considerations for Selecting an Inventory System

Choosing an Inventory Program
It is important to make several considerations before purchasing a tree inventory software program.

These can include:

1. Identify project management goals and the data needed to satisfy these goals. Extraneous data along with missing data will increase agency costs.
2. If the project uses a computer system and no upgrade is planned for the system in the near future, choose a program that will operate with the hardware and software that the project currently uses.
3. If a computer system will be purchased or an upgrade to the current system is planned, the hardware requirements for that system depend on the software programs that will be used on it. The software determines what is needed for hardware.

The consequences of not considering the above are numerous, and may include the following:

- The purchase of a program that is not satisfactory in meeting management goals.
- Over-expenditure on a program with more functionality than what is needed to satisfy management goals.
- The purchase of a computer system that does not meet software requirements.
- Over-expenditure on a computer system that has more functionality than what the agency needs.
- The purchase of a program that will not operate with the existing operating system and/or computer hardware.
- An excess of time and money spent during data collection and entry for extraneous data that are not needed to satisfy management goals.
- A lack of data that should have been collected and entered into the program in order to satisfy management goals.

Several questions should be asked before purchasing an inventory software program, including:

- Does the program integrate well with and work similarly to the other programs used by the agency (such as a word processor, spreadsheet, or scheduler)?
- Does the program store data in a common (standard) file format so that they can be used with other applications?
- Is the software developer keeping up with advances in computer technology (such as operating systems, hardware, and software standards)?
- Are software upgrades reasonably priced, and can the existing data be transferred without difficulty?
- Is the software developer reputable?
- Is the company/developer going to be around (along with their program) for the long term?
- Does the company provide sound and reasonably priced technical support?

Source: see reference in CAR (2010)

Appendix A Urban Forest Inventories and Sampling – Quantification Methodology[10]

The Urban Forest Project Protocol requires collecting information about trees over time. This can be accomplished through field surveys, where it may not be practical to perform a complete inventory of every tree in the overall population. However, it is still possible to obtain reliable information about the overall population by collecting data from a representative subset or sample. Sampling is the technique used to choose representative units for study from a larger population (see reference in CAR 2010). This appendix provides basic information about field survey and remote-sensing approaches, inventories and sampling, and lists additional resources.

A.1 Options for Data Collection

A.1.1 Field Surveys

Field or ground surveys can provide high quality data on individual trees if inspectors are well-trained and motivated. For example, tree dbh can be directly measured for use in biomass equations. Urban tree inventory includes locating the tree using a Global Positioning System (GPS), collecting relevant data, delivery of a database, and reporting findings. During a field survey information on the condition and management needs of each tree can be collected. These data may trigger actions that will improve tree growth and survival.

A.2 Complete Inventory

A complete inventory will always provide the most accurate assessment of the tree population. Typically the only bias introduced is from measurement inaccuracies.Establishing measurement protocols, training data collectors, and performing regular quality control assessments should limit this error.

The primary questions to answer when conducting both complete inventories and sampling are 1) what data are necessary to collect, 2) how should these data be recorded – on paper or electronically, and 3) what margin of error is acceptable for samples? The first two questions are data collection issues and are addressed in this section. The third question is a data analysis issue and will be addressed in the sampling section of this appendix.

From an efficiency and accuracy perspective, the use of PDAs (personal digital assistants) or other electronic devices for field data collection is preferable over recording data on paper forms. Electronic devices currently allow for immediate backup of data to a removable disk. Data could be incorrectly entered, but that occurs with paper forms as well. However, collecting data on paper opens the possibility of a second data entry error when the data are eventually entered into electronic databases for analysis. In contrast, data on PDAs or disks are transferred and immediately ready for quality control and accuracy checks.

A.2.1 Inventory Systems

There are numerous urban tree inventory systems available to consumers ranging from freeware to software packages requiring fee-for-service support. One of the most comprehensive tree inventory and management software lists available is on the USDA Forest

[10] The entirety of Appendix A is considered a quantification method.

References

California Air Resources Board. 2008. *Off-road mobile sources emission reduction program.* http://www.arb.ca.gov/msprog/offroad/offroad.htm. (May 25, 2008).

CAR. 2010, Urban Forest Project Protocol, version 1.1. Climate Action Reserve, March 10, 2010. www.climateactionreserve.org (accessed March 16, 2010).

Federal Register, Vol. 74, No. 209. (October 30, 2009)

Reporting uncertainty	The level of uncertainty associated with an entity's chosen method of sampling and/or inventorying carbon stock and calculation methodologies. Contrast with inherent uncertainty.
Tree Biomass	The amount of organic material comprising the above-ground (bole, stems and leaves) and below-ground (roots) components of a tree.
Tree maintenance plan (TMP)	Describes annual tree maintenance levels of service and associated expenditures.
Tree residue	Above-ground biomass from urban trees (as distinguished from construction debris) that can be salvaged for reuse, such as mulch, wood products, or fuel.
Tree resource	All trees planted and maintained by an entity.

	assumes that the moisture content of freshweight biomass is 30%.
Global Warming Potential (GWP)	The ratio of the time-integrated radiative forcing from the instantaneous release of one kilogram of a trace substance relative to that of one kilogram of a reference gas, i.e., CO_2. GWP factors are used to convert emissions from GHGs other than carbon dioxide to their equivalent carbon dioxide emissions.
Greenhouse gas (GHG)	"Greenhouse gas" or "GHG" means carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), sulfur hexafluoride (SF6), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), hydrocarbons and other fluorinated greenhouse gases as defined in the Regulation.
Greenhouse Gas sink	Any physical unit or process that removes a GHG from the atmosphere.
Greenhouse Gas source	Any type of emitting activity that releases GHGs into the atmosphere.
Inherent uncertainty	For this protocol, the scientific uncertainty associated with calculating carbon stocks and greenhouse gas emissions.
Leakage	Increased GHG emissions or decreased GHG removals that result from the displacement of activities or resources from inside the offset project's boundary to locations outside the offset project's boundary as a result of the offset project activity. For this protocol, shifting of activities or resources *from* other parts of the municipality, educational campus, or utility *to* the project, causing unanticipated increases in GHG emissions outside the project boundary.
Net tree gain (NTG)	Number of trees planted minus the number removed annually. NTG can be measured at the entity or project level.
Offset Credit	A tradable compliance instrument issued or approved by ARB that represents a GHG reduction or GHG removal enhancement of one metric ton of CO_2e. The GHG reduction or GHG removal enhancement must be real, additional, quantifiable, permanent, verifiable and enforceable.
Project activity	The atmospheric CO2 removal, carbon storage, emission reductions and emissions due to a GHG tree project.

11 Glossary of Terms

Additional	Greenhouse gas emission reductions or removals that exceed any greenhouse gas reduction or removals otherwise required by law, regulation, or legally binding mandate, and that exceed any greenhouse gas reductions or removals that would otherwise occur in a conservative business-as-usual scenario.
GHG reservoir	A physical unit or component of the biosphere, geosphere or hydrosphere with the capability to store, accumulate, or release of a GHG removed from the atmosphere by a GHG sink or a GHG captured from a GHG emission source. In the case of forests, GHG reservoirs include above-ground or below-ground biomass or roots, litter, soil, bole, branches and leaves, among others.
Carbon sequestration	The removal and storage of carbon from the atmosphere in greenhouse gas sinks or greenhouse gas reservoirs through physical or biological processes The process by which trees remove carbon dioxide from the atmosphere and transform it into biomass.
Carbon stock	The quantity of carbon contained in a GHG reservoir. For this protocol, urban trees are carbon stocks.
CO_2 equivalent (CO_2e)	The number of metric tons of CO_2 emissions with the same global warming potential as one metric ton of another greenhouse gas.
Dry weight (DW) biomass	The weight of aboveground tree biomass when dried to 0% moisture content. Also known as oven-dry and bone-dry biomass. Convert from green biomass to dry weight biomass by multiplying by 0.56 for hardwoods or 0.48 for softwoods.
Entity	A person, firm, association, organization, partnership, business trust, corporation, limited liability company, company, or government agency
Freshweight or green biomass	The weight of aboveground tree biomass when fresh (or green), which includes the moisture present at the time the tree was cut. The moisture content of green timber varies greatly among different species. The Reserve

the time an offset project data report is verified, the verifier will conduct a verification of each aggregated vintage year of GHG reductions or removals quantified and reported within the offset project data report.

10.1 Additional Verification Requirements

During initial verification, the verification body must determine if the methodology in the tree monitoring plan is acceptable and if it has sufficient detail for analysis during verification of the project.

9 Reporting Parameters

General requirements for monitoring, reporting, and record retention are included in the Regulation. This section provides requirements on additional reporting and procedures specific to this protocol.

9.1 Annual Reporting and Project Reporting

Offset project operators or authorized project designees must provide the following documentation annually. See Appendix D for specific requirements.

- Project tree carbon stocks (reported in tons of carbon)
- Vehicle and equipment fuel consumption associated with planting and maintenance of project trees (or all trees, if the proration approach from Section 6.2 is used)
- Project Tree Monitoring Plan, if applicable
- Project tree carbon stock change and CO_2 sequestration
- Project vehicle and equipment CO_2 emissions
- Project GHG Reduction (removal enhancement)

9.2 Document Retention

For the purposes of independent verification and historical documentation, offset project operators and authorized project designees are required to keep all information outlined in the Regulation and in this protocol for 100 years after the end of the crediting period. The list below provides specific types of system information offset project operators and authorized project designees must retain.

System information the offset project operator or authorized project designee must retain includes:

- All data inputs for the calculation of vehicle and equipment fuel consumption and CO_2 emissions, tree carbon stocks, and project GHG reductions
- CO_2e tonnage calculations
- Initial and subsequent verification records and results
- Tree monitoring plan, and all tree maintenance plans and records relevant to the urban forest project

9.3 Verification Cycle

Offset project operators or authorized project designees must submit an offset project data report for verification of GHG enhanced removals at least once every six years.

A verification statement must be received by October 1 of the next calendar year for the previous six years for which the statement is verifying project GHG removal enhancements.

10 Regulatory Verification Requirements

All offset project data reports are subject to regulatory verification as set forth in the Regulation by an ARB accredited verification body. The offset project data report must receive a positive offset or qualified positive offset verification statement to be issued compliance offset credits. At

If the potential for leakage is determined, the offset project operator or authorized project designee must explain to the verifier the changes in expenditures. Additional information on municipal, educational campus, or utility-level tree planting activities may be requested by the verification body.

8.2 Project Tree Monitoring Plan

A tree monitoring plan is important for several reasons. The plan provides sufficient and transparent information on tree measurement and monitoring. This information is used to ensure the quantification methods meet the standards of this protocol. In addition, the plan informs the project about the status of tree sites, helping to ensure that lost trees are replaced and risks of reversals are minimized. The items below must be included in a project tree monitoring plan. For further technical information on urban forest inventory and monitoring, consult Appendix A.

- Choice of method from the options in Section 6.1.
- Detailed description of procedures to census (or sample, if applicable), measure, and report information on the project trees, including the survey method, sample sizes, and method for choosing samples.
- Methods used to measure and record tree size.
- Methods used and information collected on tree survival and health.
- Statistical methods used to extrapolate sample data to the total project tree population, if applicable.
- Estimated sampling error, if applicable.

8.3 GHG Emissions and Sequestration Activity Data

The data below are required inputs for estimating project GHG reductions. Transparent reporting of this information assists with verification of the project.

- Data on the species, dimensions (including dbh), date of measurement, and location of measured trees.
- Specific equations used to calculate tree volume, biomass and carbon content.
- Make and model year, annual amount and type of fuel used by tree planting and care vehicles (or the vehicle miles traveled and average fuel economy).
- Equipment type, horsepower rating, annual amount and type of fuel consumed in tree maintenance equipment (or the number of hours equipment is used).

expenditures for each of the criteria below in the project listing form and maintain records on actual levels and expenditures each year for the project lifetime.

Tree planting:

- Number of trees planted in new tree sites each year, not including replacement trees (total for the municipality, educational campus, or utility, including project and non-project trees).
- Number of trees planted to replace removed trees each year ("replacement trees"), including replacement trees planted in relocated tree sites (separately for non-project and project trees).
- Species, size, and location of project trees planted in new tree sites each year.
- Species, size, and location of project replacement trees planted in existing or relocated tree sites each year.
- Number and location of relocated project tree sites each year.
- Reasons for relocations and, if applicable, modifications made to the project to reduce the chance of future relocations.
- Project tree resource: percentage of total project tree sites now planted.
- Annual tree planting expenditure (separately for the project and for the municipality, educational campus, or utility).

Young tree care:

- Number of young project trees inspected/pruned each year.
- Inspection/pruning cycle (total number of project trees / number treated per year).
- Annual expenditure (separately for the project and for the municipality, educational campus, or utility).

Mature tree care:

- Number of mature project trees inspected/pruned each year.
- Inspection/pruning cycle (total number of project trees / number treated per year).
- Annual expenditure (separately for the project and for the municipality, educational campus, or utility).

Tree removal:

- Number of trees removed from existing tree sites each year (separately for non-project and project trees).
- Species, size, and location[9] of project trees removed each year.
- Reasons for removals and, if applicable, modifications made to the project to reduce the chance of future removals.
- Removal cycle (total number of project trees to remove / number removed per year).
- Annual expenditure (separately for the project and for the municipality, educational campus, or utility).

Administration/other:

- Average $/tree site expenditure (total $ on admin and other / total tree numbers) (separately for the project and municipality, educational campus, or utility).
- Annual expenditure (separately for the project and for the municipality, educational campus, or utility).

[9] Tree site location must be designated on a map of the project physical boundaries.

8 Project Monitoring – Quantification Methodology[8]

General requirements for monitoring, reporting, and record retention are provided in the Cap-and-Trade Regulation. Offset project operators and authorized project designees are responsible for monitoring the performance of the project and maintaining records of monitoring data in accordance with the requirements stipulated in Section 9 and Appendix D. Monitoring is required for a period of 100 years following the final issuance of compliance offset credits to a project for quantified GHG reductions or removals.

Monitoring requirements are divided into these categories:

- Tree maintenance plan
- Tree monitoring plan
- GHG emissions and sequestration activity data

The tree maintenance plan (TMP) is used to assess the potential of leakage and other aspects of project performance. The tree monitoring plan and GHG emissions and sequestration activity data are used to verify GHG emissions and sequestration estimates.

8.1 Tree Maintenance Plan

Reporting planting and maintenance activities and expenditures is critical to assessing leakage and GHG tree project compliance. At the level of the municipality, campus, or utility, by comparing reported annual tree care expenditures for different years a verifier can assess if a boost in project activity coincides with a drop in the level of care non-project trees are receiving. At the project level, information about tree maintenance and expenditures helps assess the strength of the project and its likelihood of success. In addition, all tree planting and removal practices by the municipality, campus, or utility must be reported each year to determine the number of eligible project trees.

To standardize annual reporting of tree planting and maintenance operations, activities are grouped into five program areas: tree planting, young tree care (< 5 years), mature tree care (> 5 years), tree removal, and administration/other (e.g. clerical, training, outreach). Annual expenditures and the level of service provided are indicators for each program area. Level of service is a quantifiable measure of tree care activities performed during a year. Higher levels of service indicate greater amounts of work performed. Reporting municipalities, educational campuses, or utilities must provide a TMP that describes municipal, educational campus, or utility-level expenditures for a 10- to 20-year period and project level activities for the reporting period.

Below are the specific TMP requirements. All information is for GHG project activities and expenditures (i.e. those related to project trees), except where noted. In some cases, information about the municipality, educational campus, or utility is also required to assess leakage potential (i.e. activities and expenditures related to non-project trees). Where both project and municipal, educational campus, or utility-level information is required, this is denoted in parentheses. Otherwise the information pertains to the project only.

Note that offset project operators or authorized project designees must report on the most recent annual levels and expenditures and estimate the anticipated annual levels and

[8] The entirety of Section 8 is considered a quantification method.

7 Permanence

GHG projects involving biological carbon sequestration must address the potential reversibility of sequestered carbon, which is the loss of stored carbon after GHG offset credits have been issued. Consistent with guidance from the Intergovernmental Panel on Climate Change, ARB's underlying standard for permanence is a minimum of 100 years - the biological carbon should remain stored for 100 years (e.g. a reduction of carbon created in 2010 will remain stored until 2110 and if it is reversed, e.g. through mortality, it must be replaced).

The Regulation requires that credited GHG reductions and removals be "permanent." ARB expects offset project operators and authorized project designees to take steps to maximize the likelihood that the carbon gains of urban forest projects are preserved for 100 years or longer. To this end, the following are requirements of this protocol:

1. The requirement for all projects to monitor onsite carbon stocks, submit annual offset project data reports, and undergo third-party verification of those reports with site visits at least once every six years for the duration of the Project Life.
2. Continuous replacement of dead project trees at all tree sites during the project lifetime (i.e. projects must have an average net tree gain of no less than zero). Prior to removal, dead trees must be measured for dbh (and height, if applicable) and their carbon content calculated and recorded using procedures in Appendix B. Dead trees must be replaced within one year from when they were removed. This timeframe allows for planting to occur at the appropriate time of year (e.g. loss and removal may occur in the fall and replanting occurs in the spring). Each tree site may have one or more replacement trees over time. Also, the location of some GHG project tree sites may change due to disturbances that unexpectedly eliminate tree sites. It is the offset project operator's or authorized project designee's responsibility to promptly locate and plant replacement sites so that there is no reduction in the total number of treed project sites.
3. If reversals are not compensated for with replacement trees, ARB requires that GHG offset credits be retired in proportion to any reversals (i.e. the carbon lost, in CO_2 equivalents, from removed trees), such that the total number of issued GHG offset credits does not exceed the total quantity of carbon stored (in CO2 equivalents) by a project since its commencement date.

Table 6.4. Total Hours of Equipment Run-Time for Tree Pruning and Removal

	Pruning				Removal				
dbh	2.3-hp saw	3.7-hp saw	Bucket truck[a]	Chipper[b]	2.3-hp saw	3.7-hp saw	7.5-hp saw	Bucket truck	Chipper
1-6	0.05	NA	NA	0.05	0.3	NA	NA	0.2	0.1
7-12	0.1	NA	0.2	0.1	0.3	0.2	NA	0.4	0.25
13-18	0.2	NA	0.5	0.2	0.5	0.5	0.1	0.75	0.4
19-24	0.5	NA	1.0	0.3	1.5	1.0	0.5	2.2	0.75
25-30	1.0	NA	2.0	0.35	1.8	1.5	0.8	3.0	1.0
31-36	1.5	0.2	3.0	0.4	2.2	1.8	1.0	5.5	2.0
36+	1.5	0.2	4.0	0.4	2.2	2.3	1.5	7.5	2.5

[a] Mean HP = 43
[b] Mean HP = 99

Note: Values by dbh classes (inches) and assume crews work efficiently and equipment is not run idle.

Source: see references in CAR 2010.

6.4 Quantifying GHG Emissions from Vehicles and Equipment for Municipalities with Insufficient Data

In some instances, municipalities may not have the data necessary to calculate GHG emissions for tree planting and maintenance activities as required in Sections 6.2 and 6.3 (if, for instance, tree maintenance activities are contracted out to private entities). If data required to calculate CO_2 emissions from tree planting and maintenance activities is not obtainable, municipal projects may use a default emission factor equal to 4.17 kg CO_2 per project tree per year to calculate the annual CO_2 emissions from all, or a portion of, the tree planting and maintenance activities associated with a municipal urban forest project.[7] However, all projects must use the methods described in Sections 6.2 and 6.3 to assess CO_2 emissions from vehicles and equipment if there is sufficient data to do so. The metric listed above is based on survey results from municipal tree planting programs, and is thus only applicable to municipal urban forest projects.

[7] The default emission factor was derived from survey responses detailing annual fuel usage for the tree planting and maintenance activities of 30 municipal urban forest programs nation-wide. The default value is equal to one standard deviation above the mean of the data set.

HRS = Hours used
LF = Typical load factor
HP = Maximum horsepower
EF = Average CO_2 emissions per unit of use (kg/hr)

Typical load factors, horsepower, average emissions, and EFs for equipment are given in Table 6.3. Typical hours required for pruning and removal activities are given for maintenance equipment in Table 6.4.

Table 6.3. Typical Load Factors (LF) and Average CO_2 Emissions (EF) for Maintenance Equipment

Equipment	HP range[b]	LF[a]	EF (kg/hp/hr)[b]
Aerial lift (45 hp)	25<HP≤50	0.505	0.783
Backhoe	HP≤120	0.465	0.775
Chain saw (2 hp)	HP≤2	0.500	0.429
Chain saw (7 hp)	2<HP≤7	0.500	0.429
Chipper (50 hp)	HP≤50	0.370	0.783

[a] CAR 2010
[b] California Air Resources Board 2008

n-Butane	6.58
Propane	5.59
Residual Fuel Oil (#5,6)	10.21, 11.27
	(kg CO_2/therm)
Natural Gas	5.30

Source: Federal Register, Vol. 74, No. 209 (October 30, 2009)

The volume of fuel consumed during the crediting period can be derived from fuel records data (including bulk fuel purchase records, collected fuel receipts, official logs of vehicle fuel gauges or storage tanks). Where actual fuel use (TC) is not available, it can be estimated using vehicle information (make, model, model year, and fuel type) and annual mileage estimates by vehicle type. For each vehicle, convert annual mileage to fuel consumption using EPA's fuel economy formula below. In this equation, DP_c and DP_h are the proportion of miles traveled spent in city and highway driving conditions, respectively. A DP_c value of 0.55 and a DP_h value of 0.45 may be used as a default value, or a fleet specific number may be substituted if known.

Total Fuel Use	=	Total Mileage	/	(	Fuel Economy City	x DP_c	+	Fuel Economy Highway	x DP_h	)
(gallons)		(miles)			(mpg)			(mpg)		

Alternatively, the amount of fuel used for the eligible project trees can be estimated by prorating total fuel usage for all tree maintenance and monitoring activities of the municipality, educational campus, or utility by the number of eligible project tree sites relative to total trees managed by the municipality, educational campus, or utility.

6.3 Quantifying GHG Emissions from Equipment Related to Tree Planting and Care

Equipment emissions are associated with back hoes used in planting, and chain saws, aerial lifts, and chippers used during tree removal and pruning activities.

If the total amount of fuel consumed by equipment on GHG project-related activities is known, CO_2 emissions can be calculated using fuel-specific emission factors in Table 6.2:

$$C_{equip\ emis} = TC \times EF$$

In many cases, equipment use is tracked in hours. If the hours are known, the emissions can be calculated for each piece of equipment based on the following formula and then summed:

$$C_{equip\ emis} = HRS \times LF \times HP \times EF$$

Where,

Sampling Error*	Carbon Stock Change Adjustment (deduction by)
0 to 5%	0%
5.1 to 10%	10%
10.1 to 15%	20%
15.1 to 20%	30%
> 20%	100%

* Minimum confidence interval at 90% confidence limits.

6.2 Quantifying GHG Emissions from Motor Vehicles Related to Tree Planting and Care

Vehicle emissions are those associated with transport of personnel, supplies, and trees to and from eligible project tree sites.

Calculations of CO_2 emissions from vehicles are based on actual fuel use (gallons per year) and an emission factor (kg CO_2 per gallon) for fuel.

$C_{vehicle\ emis} = TC \times EF$

Where,

TC = Total annual fuel consumption (gallons)
EF = Emission factor by fuel type. Divide by 1,000 to convert kilograms into metric tons (t).

See the CO_2 emission factors for fuel combustion in the table below.

Table 6.2. Carbon Dioxide Emission Factors for Fuels

Fuel	CO_2 Emission Factor (kg CO_2/gallon)
Aviation Gasoline	8.31
Biodiesel (B100)	9.45
Crude Oil	10.28
Diesel 1 Diesel 2 Diesel 4	10.18 10.21 10.96
Ethane	6.01
Ethanol (E100)	5.75
Isobutane	6.29
Jet Fuel (Jet A or A-1)	9.75
Kerosene	10.15
Liquefied Petroleum Gas (LPG)	5.79
Methanol	4.15
Motor Gasoline	8.78

Approved approaches for quantifying carbon stocks:

1. Measure all trees in project tree sites during a single year (census) at multi-year intervals. Use the measurement data with approved allometric equations (Appendix B) to estimate tree volume, biomass, and carbon stocks. Data from direct tree measurements (i.e. tree dbh, diameter at breast height, and height if applicable) can be input directly into approved allometric equations.

2. Measure a sample of trees in the project tree population each year or at multi-year intervals (Appendix A), use the measurement data with approved allometric equations to estimate carbon stocks in the samples (Appendix B), and extrapolate the carbon stock estimates to the entire tree population (Appendix A). As described above in Approach 1, direct measurement must be used to estimate tree carbon stock.

6.1.2 Requirements for Tree Monitoring and Acceptable Levels of Uncertainty

In addition to the general requirements for monitoring, reporting, and record retention set forth in the Regulation, a tree monitoring plan must be included as part of the project documents (see Section 8.2 for details). The tree monitoring plan must describe in detail the approach the project plans to use to quantify carbon stocks. The document will serve as evidence for the offset project operator or authorized project designee and will communicate the methodology to the verification body.

Approach 2 involves statistical extrapolation from sample data. The sampling method must be stratified by like species and age classes (not to exceed groupings of five-year age classes). The combinations of species and age classes create independent sampling populations, or strata. Appendix A provides further details on stratified sampling design.

The resulting estimates must meet a minimum confidence level of 90% to report all of the estimated carbon stocks. If the project sampling design results in lower levels of confidence, the carbon stock estimates will be discounted according to the method below. See Appendix A for details on how to design a robust sampling program that will meet the desired level of confidence.

Descriptive statistics must be produced at the time of verification if a sampling methodology is incorporated. The estimate of carbon stock change in project trees is adjusted based on the level of confidence in the carbon stock estimate according to the table below. The table provides sampling error ranges (where sampling error is on either side of the mean estimate at the 90% confidence level), calculated with the following equation:

Sampling Error (90% confidence interval) =	*[(1 Standard Error *1.645)/(Sample mean)] x 100*

Table 6.1. Sampling Error and Carbon Stock Change Adjustment

6 GHG Calculation Methods – Quantification Methodology[6]

This section provides the detailed methods for calculating emissions and removals from the required GHG sources and sinks reported to ARB:

- Carbon storage in standing trees: *Project Tree CO_2 Sequestration*
- GHG emissions from motor vehicles related to tree planting, care, and monitoring: *Vehicle CO_2 Emissions*
- GHG emissions from equipment related to tree planting and care: *Equipment CO_2 Emissions*

Project GHG reductions (removal enhancements) are based on the amount of carbon sequestered in eligible project trees minus GHG emissions from the planting, care and maintenance of those trees over the crediting period. Below is the general formula for determining Project GHG Reductions.

Project GHG Reductions =	*Project Tree CO_2 Sequestration – Vehicle CO_2 Emissions – Equipment CO_2 Emissions*

6.1 Quantifying Project Tree CO_2 Sequestration

For each crediting period, the offset project operator or authorized project designee estimates the amount of carbon contained in eligible project trees (carbon stocks) and then uses these data to calculate an incremental carbon stock change (carbon sequestration). Carbon stock changes are reported in final units of carbon dioxide equivalent (metric tons CO_2e). The change in carbon stocks (in kilograms) is the basis for estimating project tree carbon sequestration, and is calculated using the equation below. The factor 3.67 is the molecular weight ratio of CO_2 to carbon and is used to convert carbon stock change to CO_2. The factor 0.001 is used to convert the result from kilograms to metric tons.

$$\textit{Project Tree } CO_2 \textit{ Sequestration} = (Cstock_{year\ x} - Cstock_{year\ x\text{-}n}) \dot{x} (3.67) \times 0.001$$

6.1.1 Quantifying Tree Carbon Stocks

There are approved approaches to quantifying the carbon stocks in eligible project trees, each of which is based on direct measurements of trees and approved urban tree carbon models ("allometric equations"). Consult Appendix A and Appendix B for detailed requirements on implementing the approaches.

Appendix A covers how to design tree measurement programs (inventories), including required tree measurement data and sampling techniques, design, and error. Appendix B describes how to estimate tree carbon from tree measurement data using allometric equations.

[6] The entirety of Chapter 6 is considered a quantification method.

5 GHG Assessment Boundary – Quantification Methodology[5]

The GHG Assessment Boundary delineates all relevant GHG sources, sinks, and reservoirs that are considered significantly affected by the project activity and must be included in the calculation of GHG reductions.

In this protocol, the GHG Assessment Boundary is defined as the carbon stored in standing trees and GHG emissions from motor vehicles and equipment used in tree care activities.

5.1 GHG Source Categories for Urban Forest Projects

Required GHG source and sink categories for reporting are as follows:

- Carbon stored in standing trees
- CO_2 emissions from motor vehicles related to tree planting, care, and monitoring
- CO_2 emissions from equipment related to tree planting and care

CO_2 is the primary GHG to report for urban forest projects.

5.2 Leakage

Leakage is an increase in GHG emissions or decrease in sequestration caused by the project but not accounted for within the project boundary. In the case of urban forest projects, the most likely form of leakage is the shifting of funds and maintenance from non-project tree resources (i.e. trees within the municipality, educational campus, or utility service area that are not part of the project) to project trees within a municipality, educational campus, or utility service area. For example, if funding is reduced for pruning existing trees to fund a GHG tree planting project, there may be an overall decline in the health of the urban forest within a municipality, educational campus, or utility service area and a long-term increase in mortality. A tree maintenance plan (TMP) is used to assess whether this type of activity-shifting leakage is occurring. Details on the TMP requirements are provided in Section 8. If annual expenditures of the municipality, educational campus, or utility (separate from project expenditures) in one or more program areas decrease by more than 10% from amounts in the initial TMP or from amounts in the previous year TMP, and these changes cannot be explained by the offset project operator or authorized project designee to the verifier, leakage will be assumed and if confirmed, no GHG offset credits can be issued in that year.

[5] The entirety of Chapter 5 is considered a quantification method.

4 Project Boundary – Quantification Methodology[4]

The project boundary outlines the components of the project operations that are impacted by the project activity, including the physical area covered by the project as well as the specific equipment used by the project. In this protocol the project boundary includes:

- The number of eligible project tree sites (determined in Section 3)
- Equipment used to plant and maintain the trees

Tree sites must be located within the boundary of a municipality, educational institution, or utility. Boundaries are determined by the physical area owned and/or controlled by a municipality or educational campus, or the service area covered by a utility.

For each project type, eligible project trees must be planted:

- Along streets, in parks, city golf courses, cemeteries, near city buildings, greenbelts, city parking lots, and other public open space, or on private property in municipalities
- Along streets, near classrooms, dorms, office buildings, near recreational fields and other facilities, in parking lots, arboretums, and other open space on educational campuses
- In parks, streets, parking lots, private property, and open spaces by utilities

Tree plantings must have an average spacing of no less than 5 meters (biomass equations for estimating carbon stock changes are for open-growing urban trees and assume relatively intensive management. The spatial location of all project tree sites must be known and recorded (e.g. using GPS or GIS).

[4] The entirety of Chapter 4 is considered a quantification method.

and maintenance of the eligible project trees are the basis for calculating project GHG reductions.

If the municipality or educational campus reports a negative NTG in any given year, no new trees planted that year can be considered eligible project trees and no offset credits can be issued. When the municipality or educational campus returns to an average annual NTG of zero or greater, offset credits for GHG reductions from project trees during the intervening years (up to a maximum of five years) can be issued ex-post upon verification, as long as the criteria in this protocol for project trees were met during those years.

Utilities

Most utilities do not have tree planting programs that go beyond replacing trees removed during line clearance operations. While some have programs specifically aimed at storing carbon and conserving energy in residential households, on average utilities are planting fewer than 400 trees annually in these types of programs. All trees planted under these types of programs are considered additional and therefore are designated as eligible project trees. These trees may be used to generate GHG reductions, provided all criteria in this protocol and the regulation are met.

3.5 Regulatory Compliance

Offset project operators or approved offset project designees must fulfill all applicable local, regional and national requirements for environment impact assessments that apply based on the offset project location. Projects must also meet any other local, regional, and national requirements that might apply. Projects are not eligible to receive offset credits for GHG removal enhancements that occur as the result of activities that are not in compliance with regulatory requirements.

partner organization/individual working with a municipality, educational campus, or utility plants trees outside the project boundary, these activities should not be included in the comparison.

Municipalities and Educational Campuses

The business as usual thresholds for municipalities and educational campuses are measured in terms of net tree gain (NTG), i.e., the annual number of trees planted by a municipality or educational campus minus the annual number of trees removed by a municipality or educational campus. Only project activity that exceeds this threshold can be listed.

The threshold for municipalities and educational campuses is set at maintaining a stable urban forest population (i.e. a NTG of 0). In other words, municipalities and educational campuses must plant at least as many trees as they remove.

In addition to the requirements for project listing, the offset project operator or authorized project designee must demonstrate a priori that a project will exceed the threshold, by calculating the anticipated NTG of the municipality, or educational campus, based on recent activities and anticipated project activities. Specifically, the calculation must be based on:

1. The annual average number of urban trees planted and removed in the municipality or educational campus over no more than the most recent five year period preceding the project commencement date, or using data from a single year occurring at some point during the past most recent five year period.
2. The expected average annual number of GHG project tree sites to be planted by the project.
3. Where urban trees include trees under the municipality or educational campus ownership or control and are open-grown in managed landscapes.

In addition to the general requirements for monitoring, reporting, and record retention set forth in the Regulation, for each year of the project the offset project operator or authorized project designee is required to report an annual average NTG (number of urban trees planted minus removed) for the municipality, or educational campus, including regular activities (planting of "non-project" trees) and project activities (planting of "project" trees). The annual average NTG must be based on a five-year rolling average (i.e. the most recent previous five years including the reporting year), except in the first five years of the project when the average may be based on less than five years of data (i.e. one-year average in the first year of the project, two-year average in the second year). When the average annual NTG for the municipality or educational campus is positive (more trees are planted than removed), the number of trees planted in excess of the number removed determines how many eligible project trees can be designated that year. Specific eligible project trees are identified each year by the offset project operator or authorized project designee and tracked individually for the duration of the project. Carbon sequestration and GHG emissions from tree care, monitoring,

authorized project designee must submit the information in Appendix C to meet the listing requirements in the Regulation. Responsibility for tree planting, care, and maintenance activities may reside with either the offset project operator or an authorized project designee.

3 Eligibility Rules

General eligibility requirements for offset projects are set forth in the Regulation. Offset project operators or authorized project designees using this protocol must satisfy the following eligibility rules to receive compliance offset credit.

3.1 Location

Only projects located in the United States and its territories, or on U.S. tribal lands, are eligible under this protocol. Project tree sites must be located according to the requirements in Section 5 (average spacing of no less than 5 meters and placement along streets, in parks and parking lots, etc.) Thus, urban forest projects must take place in urban or other types of developed areas.

3.2 Project Commencement

Project commencement for an urban forest project is defined as the date at which the project implements a planned set of tree planting activities and becomes operational. For the purposes of this protocol, the commencement of operation means when trees are planted and regular maintenance begins. As stated in the Regulation, projects with commencement dates prior to December 31, 2006 are not eligible under this protocol. Projects may always be submitted for listing prior to their commencement date.

3.3 Project Crediting Period

As set forth in the Regulation, the crediting period for sequestration projects cannot be less than 10 years and no greater than 30 years. The crediting period for this project type is 25 years. Requirements for renewal of project crediting periods are set forth in the Regulation.

3.4 Additionality

The protocol must meet the additionality requirements in the Regulation. In summary the activity must not be required by or undertaken to comply with any federal, state, or local law or ordinance in the project's jurisdiction.

3.4.1 Net Tree Gain – Quantification Method

The project must demonstrate a priori that it will exceed the business as usual threshold, and information confirming this, in accordance with the requirements below, must be provided in the documentation for applying for project listing as set forth in Appendix C.

The business as usual threshold comparison for municipalities, educational campuses and utilities is based on information within the area the project will take place. If a

2 The GHG Reduction Project

2.1 Project Definition – Quantification Methodology

For the purpose of this protocol, the GHG reduction ("removal enhancement") project is defined as a planned set of tree planting and maintenance activities that permanently increase carbon storage, taking into account GHG emissions associated with planting and maintenance of project trees.

While project trees are planted for the purposes of the urban forest GHG project, tree sites are the primary unit of analysis. A tree site contains one tree at a time, however, the tree may be replaced over time and the site itself may be moved. This is because project trees are subject to mortality and other types of losses and therefore may need to be replaced and/or relocated during the project lifetime (see Section 7 for details).

This protocol is not applicable for forest management and conservation activities that occur on large natural forested tracts within cities (≥ 100 acres contiguously forested and containing dead downed woody material).

An offset project operator or authorized project designee can assemble several smaller projects into a single project for the purposes of achieving economies of scale and more efficient reporting. However, reporting, monitoring, and verification practices must follow regulation requirements set forth in this protocol and the Cap-and Trade Regulation.

This protocol is applicable to three specific project types: urban forest GHG projects undertaken (1) in municipalities[2], (2) on educational campuses[3], and (3) by utilities. A project is defined by a specific number of project tree sites, determined a priori, that will be planted and maintained within one of the above types of entities over the project lifetime. If the offset project operator or authorized project designee intends to plant more project tree sites than the number defined under the original project, this constitutes a second, distinct urban tree project. Offset project operators or authorized project designees can undertake as many urban tree projects as desired in the future as long as they each, separately, meet the eligibility criteria and reporting requirements in this protocol and set forth in the regulation.

2.2 The Offset Project Operator and Authorized Project Designee

The offset project operator or authorized project designee is responsible for project listing, monitoring, reporting and verification. The offset project operator or authorized project designee must have legal authority to implement the offset project. For the purpose of this protocol, an offset project operator or authorized project designee must represent a municipality, educational institution, or utility. The offset project operator or

[2] Including cities, counties, and other local agencies or special districts.

[3] As noted in Section 4, the physical area owned and/or controlled by the municipality, educational campus, or utility determines municipal, campus, or utility service area boundaries. In the case of educational campuses, the project developer may define the entity as a single campus or a system of campuses, as long as the definition is clearly stated and the entity can demonstrate that it has ownership and/or control over the physical area.

1 Introduction

The Compliance Offset Protocol for Urban Forest Projects provides methods to quantify and report greenhouse gas (GHG) removal enhancements associated with a planned set of tree planting and maintenance activities to permanently increase carbon storage in trees. This protocol is based on The Climate Reserve's Urban Forest Project Protocol Version 1.1 (CAR 2010).

Offset project operators or authorized project designees that implement tree-planting programs must use this protocol to quantify and report GHG removal enhancements that may be eligible to receive compliance credits for use in the Air Resources Board's (ARB) compliance offset program. The protocol provides eligibility rules, methods to quantify removal enhancements, project-monitoring instructions, and procedures for reporting offset project data reports. Additionally, all projects must submit to independent verification by ARB-accredited verification bodies at least once every six years. Requirements for verification bodies to verify offset project emissions data reports are provided in the Cap-and-Trade Regulation.

To register urban forest project GHG removal enhancements, offset project operators and authorized project designees are not required to prepare and submit an annual municipal, campus, or utility-level GHG inventory..

AB 32 exempts quantification methodologies from the Administrative Procedure Act (APA)[1], however those elements of the protocol are still regulatory. The exemption allows future updates to the quantification methodologies to be made through a public review and Board adoption process but without the need for rulemaking documents. Each protocol identifies sections that are considered quantification and exempt from APA requirements. Any changes to the non-quantification elements of the offset protocols would be considered a regulatory update subject to the full regulatory development process. Those sections that are considered to be a quantification methodology are clearly indicated in the title of the chapter or subchapter if only a portion of that chapter is considered part of the quantification methodology of the protocol.

[1] Health and Safety Code section 38571.

Abbreviations and Acronyms

ARB	California Air Resources Board
C	Carbon
CH_4	Methane
CO_2	Carbon dioxide
dbh	Diameter at breast height
GHG	Greenhouse gas
lb	Pound
N_2O	Nitrous oxide
NTG	Net tree gain
Regulation	Cap-and-Trade Regulation, title 17, California Code of Regulations, sections 95800 et seq.
Reserve	Climate Action Reserve
TMP	Tree maintenance plan
USFS	United States Forest Service

i. Ranks – ordered ratings, e.g. low, moderate, high
ii. Counts – e.g. number of trees by species or dbh class
iii. Binary – variable has only two outcomes, e.g. present/absent. Binary data is typically expressed as proportions or percents, such as the percent canopy cover determined from dot grid counts (canopy is rated as present or absent for each dot)

Type of Analysis

Continuous data are typically analyzed using linear models, including linear regression and analysis of variance techniques. Discrete data may be analyzed in various ways, including contingency table analysis, logistic regression, and survival analysis. Different formulas are used to estimate sample sizes for various analysis methods.

Expected Values

To estimate sample sizes for analyses of continuous data, estimates of expected population means (the Greek letter mu may be used for this term) and standard deviations or variances (the Greek letter sigma symbolizes the population standard deviation; variance is the square of the standard deviation) will have to be specified. For proportions, estimates of the expected proportions are needed; margins of error (as percents) may also be needed.

Data Structure

If data are paired or arranged in blocks or other more complex designs, the structure of the statistical model should be specified.

Confidence Level

Also abbreviated as the Greek letter alpha, this is the probability of Type I error, the chance that a difference is significant when it really is not (i.e. the probability of rejecting the null hypothesis when it is true). This is typically set at a low level, often 5% (alpha=0.05), meaning that there would only be a 5% (1 in 20) chance of deciding that a spurious difference is real (i.e. a 95% chance of avoiding Type I error).

Power

This parameter is expressed as (1-beta) where beta is the probability of Type II error. Power is the probability of detecting a real difference (i.e. the probability of rejecting the null hypothesis when it is false). When detecting real differences, the power of a test should be high, ger rally at least 80% (0.8) or greater.

A.3.6 Sampling Design and Monitoring Frequency

The frequency of monitoring is related to the rate and magnitude of change in tree growth, removal rates, planting rates and so forth – the smaller the expected change, the greater the potential that frequent monitoring will not detect a significant change. Frequency of monitc ing should be determined by the magnitude of expected change – less frequent monitoring is applicable if only small changes are expected (see reference in CAR 2010).

All sampling designs should incorporate some form of random sampling to quantify the carbon stocks within established project boundaries using statistically accepted methods for inferring the urban forest biomass based on sample plots. There are multiple ways one can design a sampling plan. Although a few examples are provided here, it is important to remember that the specific sampling method used should be determined after evaluating project size, monitoring

frequency and acceptable level of sampling error. Four basic designs are addressed here and additional resources are provided in the reference section.

1. ***Rolling Sample***
   A percentage of the complete inventory is sampled annually, with results used to infer biomass or volume for the complete inventory.

   Example: during year 1 a non-profit tree group plants 3,000 new tree sites along a greenway, with a variety of species mixed throughout the area. Each year, 10% of the tree sites are sampled, until, at the end of 10 years, 100% of the inventory has been sampled. The annual 10% samples are fixed samples proportional to representation. Thus, the complete inventory is divided into 10 samples at the outset of the project. These 10% samples may be based on stratified random sampling with species type and frequency (number of trees planted per species) as the strata, or to reduce data collection costs, trees could be clustered into 10 cohorts based on geographic proximity. Other forms of random sampling, including cluster sampling for obtaining the 10% sample may also be suitable.

2. ***Periodic Sampling***
   All trees are re-inventoried but not annually. A sampling period is determined at the outset. For example, all trees are re-inventoried every 6 years.

3. ***Fixed Plot Sampling***
   All trees in a geographical area are never completely inventoried. A set of plots of fixed size and number are established and used to extrapolate volume or biomass on an area basis. Example: the city of San Francisco establishes a new 30-mile long multi-use greenway along a former railroad corridor. They employ the UFORE plot sampling method (see references in CAR 2010) and establish thirty 10-m radius permanent plots based on land use stratification. The plots are sampled annually. Biomass or volume for the greenway is extrapolated based on sample plots to area relationship.

4. ***Variable Plot***
   Variable plot is similar to fixed plot sampling except the area sampled varies to coincide w/ logistical requirements, such as property boundaries where permission to access private property is required. Area of the plot is measured and used to infer to the total area based on plot area to total area ratio.

Note that items 1 and 2 can be applied to items 3 and 4; they are potentially at different levels or scales within a sampling design. There are many additional methods for sampling. See the list of recommended references and resource guidelines for developing sampling methodologies and finding statistical support for sampling and extrapolation at the end of this appendix.

A.3.7 Minimum Required Sampling Criteria

All sampling methodologies and measurement standards must be statistically sound and reviewed by verification bodies. All sample plots should be permanently benchmarked for auditing and monitoring purposes. Plot centers, street segments, or individual trees (in the case of some forms of rolling samples) should be referenced on maps, preferably using GPS coordinates or using GIS. The methods utilized shall be documented and made available for verification and public review. The design of the sampling methodology and measurement standards must include the requirements stated in Table A.2.

Table A.2. Minimum Required Sampling Criteria

GHG Reservoir	Required?	Name of Requirement	Description of Requirement
Tree Biomass	Yes	Diameter (breast height) Measurements	Stated minimum diameter in methodology not to be greater than 7.6 cm (3 in.)
		Measurement Tools	Description of tools used for height, diameter, and plot measurement.
		Measurement Standards	The methodology shall include a set of standards for height and diameter measurements and describe compliance with allowable measurement error.
		Stratification Design	A description of the rules used to stratify the trees.
		Plot Layout	A description of the plot layout.
		Allometric Equations used for Estimating Biomass	The methodology shall include a description of the allometric equations used to estimate the whole tree biomass (bole, branches, and roots) from bole diameter measurements. This includes a description of how equations were assigned and implemented. Use only the equations provided in this protocol.

A.3.8 Sampling Error

ARB requires all estimates of reported GHG reservoirs, required or not, to have a high level of statistical confidence. Measurement standards are established by ARB for the carbon tonne estimate in the required pools derived from sampling. Confidence in the estimate of carbon tonnes from sampling can be measured statistically in terms of the size of the standard error relative to the estimate of the mean. This establishes confidence limits and can be expressed as a percentage of the mean. Larger confidence intervals indicate that there is less confidence in the mean estimate than smaller confidence intervals. For all GHG reservoirs reported to ARB, the standard error must be within 20% of the estimate of the mean for the estimate to be accepted. However, estimates are adjusted based on the statistical level of confidence, such that only estimates with a standard error within 5% or less receive no deduction. Most spreadsheet software packages provide users the ability to run descriptive statistics on a set of data, and results include the mean, standard error, standard deviation and confidence level. Table A.3 provides an example of summary results for each plot in a measured stratum. Note that standard deviation quantifies the scatter, how much the measured values differ from one another, whereas, standard error quantifies how accurately the true mean of the population is known. Standard error gets smaller as the sample gets larger, but standard deviation does not change predictably since it only quantifies scatter.

Table A.3. Summary Results for Each Plot in a Stratum

Plot #	Carbon Tons per Hectare	Plot #	Carbon Tons per Hectare	Plot #	Carbon Tons per Hectare
1	337	8	367	15	342
2	296	9	260	16	366
3	308	10	260	17	355
4	271	11	322	18	423
5	289	12	323	19	437
6	228	13	439	20	156
7	144	14	309		
Average Carbon Tons per Hectare.					312
Standard error (must be <20% of mean)					17.85

Note: Confidence level is less than 10% of the mean as required by ARB.

A.4 Conclusion

Data collection through complete inventory or sampling represents a means to an end – information used to calculate and report carbon stocks. What sampling methods are used to collect data and how that data are subsequently analyzed will influence predictions of carbon stocks and GHG emission reductions. It is always best to consult with a statistician when deciding upon a sampling scheme. There is little a statistician can do to help once the project follows an inappropriate sampling design.

In collecting necessary information about the project, the final product must be considered – what are the project goals in collecting data and what information does that data need to provide for the project? There is a series of checklists produced by Jeffers (http://www.sawleystudios.co.uk/jnrj/Statistical.htm) and used by researchers and statisticians world-wide to help them remember all there is to consider regarding data collection and analysis. The website provides individual lists of questions to ask regarding 1) design of experiments, 2) sampling, 3) modeling, 4) plant growth analysis, and 5) multivariate analysis.

Appendix B Calculating Biomass and Carbon – Quantification Methodology[11]

This appendix describes how measured tree size data are used with biomass equations to calculate tree volume and carbon content. Equations are presented for 26 open-grown urban tree species. To be consistent with biomass equations used in the Forest Project Protocol, foliar biomass is not included in the formulations. Additional biomass equations have been adapted from the literature on natural and native forest biomass for use in urban settings. The urban species equations have also been used to develop two general equations for broadleaf trees and conifers. Complete listings of equations are available in Table B.1 and Table B.2 at the end of this appendix. Table B.1 lists equations based on measurements of dbh and height or dbh only, derived from data collected on open-grown trees.

B.1 Estimating Biomass and Carbon Using Volumetric Equations

Estimating biomass and carbon using volumetric equations is a two-step process that entails 1) calculating green volume, and 2) converting green volume to dry weight biomass and then carbon content (C). Table B.1 and Table B.2 provide examples of volumetric equations and biomass conversion factors for common urban species (see references in CAR 2010). Table B.1 equations estimate volume (m^3/tree) from diameter at breast height (dbh in centimeters) and height (in meters) measurements.

1. Use equations for dbh and height (or equations for dbh only if necessary) to calculate volume.

   Example:
   Volume in cubic meters (V) for a 15.6 m tall hackberry (*Celtis occidentalis*) with a 40.4 cm dbh is calculated as:

$$V = 0.002245 \times (40.4)^{2.118} \times (15.6)^{-0447} \quad \text{[Eq. 1]}$$
$$= 1.66\ m^3$$

2. Determine freshweight (FW) biomass, dry weight (DW) biomass and carbon content by applying biomass conversion factors in Table B.1, incorporating belowground biomass, and calculating carbon.

   a. Convert from volume to FW biomass by multiplying V by the species-specific density factor.

      For hackberry, FW would be calculated as:

$$FW = 1.66 \times 801 \quad \text{[Eq. 2]}$$
$$= 1329.66\ kg$$

[11] The entirety of Appendix B is considered a quantification method.

b. The equations given here only calculate volume (and hence biomass) for the *aboveground* portion of the tree. Add the biomass stored belowground by multiplying the FW biomass by 1.28. For total FW biomass, including belowground roots calculate:

$$\text{Total FW} = 1329.66 \times 1.28 = 1704.62 \text{ kg} \quad \text{[Eq. 3]}$$

c. Convert FW biomass into DW biomass by multiplying by the constant 0.56 for hardwoods and 0.48 for conifers (see reference in CAR 2010). For our hackberry example:

$$\text{DW} = 1704.62 \times 0.56 = 954.59 \text{ kg} \quad \text{[Eq. 4]}$$

d. Convert DW biomass into kilograms of carbon (C) by multiplying by the constant 0.50:

$$\text{C} = 954.59 \times 0.5 = 477.30 \text{ kg} \quad \text{[Eq. 5]}$$

e. Tree carbon stock is to be reported in metric tons. Therefore, results calculated in kilograms must be multiplied by 0.001 to convert to metric tons.

B.1.1 Estimating Biomass and Carbon Using Forest-Derived Equations

Biomass calculated using equations derived from native or natural forest trees (Table B.2) must be adjusted by a factor of 0.80 when applied to open-grown, urban trees (see reference in CAR 2010) because of differences in biomass allocation between the tree populations.

Unlike the equations used above, the forest equations listed produce DW biomass rather than FW biomass. Therefore the step involving the species-specific density factor (step 2a above) does not need to be incorporated. The calculation for carbon content (kg) is:

$$\text{C} = \text{DW} \times 1.28 \times 0.5 \quad \text{[Eq. 7]}$$

B.1.2 Estimating Tree Biomass for Standing Dead or Dying Trees

Unlike trees in forest settings, dead or dying trees in urban areas are usually removed immediately due to safety concerns in public and private areas. Typically, the only difference between biomass in a live tree and that in a dead tree is the absence of foliage for the latter. Because foliar biomass is not included in these formulations, dead and dying tree biomass should be calculated just as for live tree biomass.

B.1.3 Estimating Carbon in Lying (Dead/Downed) Tree Biomass

As discussed in Section B.1.2 above, it is assumed in nearly all urban applications that dead/dying trees are removed almost immediately and that lying tree biomass will rarely, if ever exist. It is most likely to exist in natural settings within cities like riparian or nature areas. In that case, sampling, measurement and carbon estimation procedures should follow the forest protocol rather than the urban forest protocol.

B.2 Error in Estimating Carbon and Biomass

The volume equations used in this protocol were developed from trees that may differ in size from the trees in a specific sample or inventory. The dbh ranges for trees sampled to develop the volume and biomass equations are listed where known at the end of the appendix (Table B.1 and Table B.2). Applying the equations to trees with dbh outside of this range may increase the error in estimates.

B.3 Reporting Uncertainty versus Inherent Uncertainty

Reporting uncertainty is the level of uncertainty associated with an entity's chosen carbon stock sampling and calculation methodologies. Inherent uncertainty refers to the scientific uncertainty associated with calculating carbon stocks and GHG emissions.

The ARB is aware that there is an inherent scientific uncertainty in quantifying carbon stocks of entities. However, determining scientific accuracy is not the focus of the ARB. Instead, the ARB's verification process is designed to identify and assess reporting uncertainty. Therefore, when assessing if the estimate of the carbon content in project trees meets the ARB's minimum quality standard, only quantification differences that result from reporting uncertainty should be considered, not inherent uncertainty. Therefore, it is not necessary to attempt to quantify error for biomass equations accepted by the ARB. Any statistical error associated with these equations falls under the category of inherent uncertainty.

Table B.1. Volume Equations for 26 Urban Tree Species

	Species	DBH Range (cm)	Volume (m^3)	Vol to FW Conversion kg/m3
	Acacia longifolia	15.0 - 57.2	$=0.0283168466\ (0.048490 * (dbh/2.54)^{2.347250})$	1121
	Acer platanoides	9.7 - 102.1	$=0.0019421 * dbh^{1.785}$	737
	Acer saccharinum	13.2 - 134.9	$=0.000363 * dbh^{2.282}$	721
	Celtis occidentalis	10.9 - 119.4	$=0.0014159 * dbh^{1.929}$	801
	Ceratonia siliqua	15.5 - 71.4	$=0.0283168466(0.066256 * (dbh/2.54)^{2.128861})$	961
D	Cinnamomum camphora	12.7 - 68.8	$=0.0283168466(0.031449 * (dbh/2.54)^{2.534660})$	817
B	Cupressus macrocarpa	15.7 - 146.6	$=0.0283168466(0.035598 * (dbh/2.54)^{2.495553})$	577
H	Eucalyptus globulus	15.5 - 130.0	$=0.0283168466(0.055113 * (dbh/2.54)^{2.436970})$	1121
	Fraxinus pennsylvanica	14.7 - 122.7	$=0.0005885 * dbh^{2.206}$	785
O	Fraxinus velutina 'Modesto'	14.5 - 84.8	$=0.0283168466(0.022227 * (dbh/2.54)^{2.633345})$	769
H	Gleditsia triacanthos	9.1 - 98.3	$=0.0005055 * dbh^{2.220}$	977
L	Gymnocladus dioicus	10.2 - 36.8	$=0.0004159 * dbh^{2.659}$	929
Y	Jacaranda mimosifolia	17.3 - 59.7	$=0.0283168466(0.036147 * (dbh/2.54)^{2.486249})$	609
	Liquidambar styraciflua	14.0 - 54.4	$=0.0283168466(0.030684 * (dbh/2.54)^{2.560466})$	801
	Magnolia grandiflora	14.5 - 74.2	$=0.0283168466(0.022744 * (dbh/2.54)^{2.622015})$	945
	Pinus radiata	16.8 - 105.4	$=0.0283168466(0.019874 * (dbh/2.54)^{2.656075})$	705
	Pistacia chinensis	12.7 - 51.3	$=0.0283168466(0.019003 * (dbh/2.54)^{2.808635})$	657
	Platanus acerifolia	15.5 - 73.9	$=0.0283168466(0.025170 * (dbh/2.54)^{2.673576})$	833
	Populus sargentii	6.4 - 136.7	$=0.0020891 * dbh^{1.873}$	753
	Quercus ilex	12.7 - 52.1	$=0.0283168466(0.025169 * (dbh/2.54)^{2.607285})$	1186
	Quercus macrocarpa	10.9 - 100.1	$=0.0002431 * dbh^{2.415}$	993
	Tilia cordata	11.2 - 64.5	$=0.0009359 * dbh^{2.042}$	673
	Ulmus americana	17.5 - 114.3	$=0.0018 * dbh^{1.869}$	865
	Ulmus parvifolia chinensis	17.3 - 55.9	$=0.0283168466(0.026530 * (dbh/2.54)^{2.639344})$	865
	Ulmus pumila	15.5 - 131.6	$=0.0048879 * dbh^{1.613}$	865
	Zelkova serrata	14.5 - 86.4	$=0.0283168466(0.021472 * (dbh/2.54)^{2.674791})$	865
	General Broadleaf	6.4 - 136.7	$=0.280285*(dbhcm)^{2.310647}$	Eqtn produces FW
	General Conifer	6.4 - 136.7	$=0.05654*(dbhcm)^{2.580671}$	Eqtn produces FW
	Acacia longifolia	15.0 - 57.2	$=0.0283168466(0.01406 * (dbh/2.54)^{2.186419} * (3.28*ht)^{0.467362})$	1121
	Acer platanoides	9.7 - 102.1	$=0.001011 * dbh^{1.533} * ht^{0.657}$	737
	Acer saccharinum	13.2 - 134.9	$=0.000238 * dbh^{1.998} * ht^{0.556}$	721
D	Celtis occidentalis	10.9 - 119.4	$=0.002245 * dbh^{2.118} * ht^{0.447}$	801
B	Ceratonia siliqua	15.5 - 71.4	$=0.0283168466(0.00857 * (dbh/2.54)^{1.295834} * (3.28*ht)^{0.520967})$	961
H	Cinnamomum camphora	12.7 - 68.8	$=0.0283168466(0.00982 * (dbh/2.54)^{2.134160} * (3.28*ht)^{0.634045})$	817
	Cupressus macrocarpa	15.7 - 146.6	$=0.0283168466(0.00576 * (dbh/2.54)^{2.360035} * (3.28*ht)^{0.630015})$	577
a	Eucalyptus globulus	15.5 - 130.0	$=0.0283168466(0.00309 * (dbh/2.54)^{2.151682} * (3.28*ht)^{0.839573})$	1121
n	Fraxinus pennsylvanica	14.7 - 122.7	$=0.000414 * dbh^{1.847} * ht^{0.646}$	785
d	Fraxinus velutina 'Modesto'	14.5 - 84.8	$=0.0283168466(0.00129 * (dbh/2.54)^{1.762596} * (3.28*ht)^{1.427852})$	769
	Gleditsia triacanthos	9.1 - 98.3	$=0.000489 * dbh^{2.132} * ht^{0.142}$	977
H	Gymnocladus dioicus	10.2 - 36.8	$=0.000463 * dbh^{1.545} * ht^{0.792}$	929
E	Jacaranda mimosifolia	17.3 - 59.7	$=0.0283168466(0.01131 * (dbh/2.54)^{2.186576} * (3.28*ht)^{0.548805})$	609
I	Liquidambar styraciflua	14.0 - 54.4	$=0.0283168466(0.01177 * (dbh/2.54)^{2.315822} * (3.28*ht)^{0.415711})$	801
G	Magnolia grandiflora	14.5 - 74.2	$=0.0283168466(0.00449 * (dbh/2.54)^{2.070141} * (3.28*ht)^{0.834555})$	945
H	Pinus radiata	16.8 - 105.4	$=0.0283168466(0.00533 * (dbh/2.54)^{2.226891} * (3.28*ht)^{0.666859})$	705
T	Pistacia chinensis	12.7 - 51.3	$=0.0283168466(0.00292 * (dbh/2.54)^{2.191657} * (3.28*ht)^{0.943367})$	657
	Platanus acerifolia	15.5 - 73.9	$=0.0283168466(0.01043 * (dbh/2.54)^{2.436442} * (3.28*ht)^{0.391669})$	833
	Populus sargentii	6.4 - 136.7	$=0.001906 * dbh^{1.905} * ht^{0.134}$	753
	Quercus ilex	12.7 - 52.1	$=0.0283168466(0.00431 * (dbh/2.54)^{1.852158} * (3.28*ht)^{1.063659})$	1186
	Quercus macrocarpa	10.9 - 100.1	$=0.000169 * dbh^{1.956} * ht^{0.842}$	993
	Tilia cordata	11.2 - 64.5	$=0.000945 * dbh^{1.851} * ht^{0.559}$	673
	Ulmus americana	17.5 - 114.3	$=0.0012 * dbh^{1.626} * ht^{0.406}$	865
	Ulmus parvifolia chinensis	17.3 - 55.9	$=0.0283168466(0.01046 * (dbh/2.54)^{2.332481} * (3.28*ht)^{0.493117})$	865
	Ulmus pumila	15.5 - 131.6	$=0.000338 * dbh^{0.855} * ht^{2.041}$	865
	Zelkova serrata	14.5 - 86.4	$=0.0283168466(0.00666 * (dbh/2.54)^{2.365316} * (3.28*ht)^{0.551190})$	865

Note: Equations require dbh (cm) only or dbh (cm) and height (m) measurements to calculate volume. Factors are listed for converting volume to freshweight (FW), and two FW general biomass equations derived from these species are also listed.

Source: CAR 2010.

Table B.2. Dry Weight Biomass Equations

Spcode	Botanic	Common	Model	Source and DBH Range
ACRU	Acer rubrum	Red maple	$=(0.1970*(dbh^{2.1933}))*0.80$	Ter-Mikaelian, Nova Scotia 0-35 cm red maple
ACSA2	Acer saccharum	Sugar maple	$=((0.1791*(dbh^{2.3324}))*0.80$	Ter-Mikaelian, Maine 3-66 cm sugar maple
PRSE2	Prunus serotina	Black cherry	$=((0.0716*dbh^{2.8174}))*0.80$	Ter-Mikaelian, West VA 5-50 cm black cherry
QURU	Quercus rubra	Northern red oak	$=(0.1130*(dbh^{2.4672}))*0.80$	TerMikaelian, West VA 5-50 cm red oak
FRAM	Fraxinus americana	White ash	$=(0.1063*(dbh^{2.4798}))*0.80$	Ter-Mikaelian, West VA 5-50 cm white ash
TIAM	Tilia americana	American basswood	$=((0.0617*dbh^{2.5328}))*0.80$	Ter-Mikaelian, West VA 5-50 cm basswood
BENI	Betula nigra	River birch	$=(0.0692*(dbh^{2.6606}))*0.80$	Ter-Mikaelian, West VA 5-50 cm black birch
Palms	General palms	General palms	=(6.0*ht(m)+0.8)+(0.8*ht(m)+0.9)	Frangi and Lugo, 1985
Hardwoods	General hardwoods	General hardwoods	=((EXP(-2.437+2.418*(LN(dbh)))+EXP(-3.188 + 2.226*(LN(dbh)))))*0.8	Tritton and Hornbeck, Northeast, 10-50 cm

Note: Use constants to add roots, convert to carbon. Biomass is reduced to 80% of original predicted value to account for less biomass in urban trees.

Appendix C Urban Forest Project Listing Form

Section 1: General Information

1. Date of form completion:
2. Form completed by (name):
3. Project listing as a:
   - Municipal Project
   - Educational Campus Project
   - Utility Project
4. Name and contact information of the Offset Project Operator:
5. Name and contact information of Authorized Project Designee (if applicable):
6. Project Commencement Date:
7. Date of initial reporting year:
8. Location of project (including approximate latitude/longitude):

Section 2: Project Summary

1. Describe the goals of the project.
2. Name of the person or entity that is responsible for planning, implementation, and reporting of project activity. List and explain the involvement of Authorized Project Designees, if applicable.
3. Briefly describe implementation of the project. Include general information on the number of project tree sites and trees that will be planted (including replacements), types of species, where they will be planted, tree maintenance and monitoring plans (Note: Some of this information is also required in the Tree Maintenance Plan [separate document]):
4. Confirm that the trees will be planted in maintained landscapes and spaced at least 5 m (16 ft) apart so as to be open-growing (Y/N):

Section 3: Project Boundaries

1. Physical Boundary: Describe and include a map of the physical boundary of the project, including planned tree sites, an outline of the geographical boundary of the municipality, educational campus, or utility service area, and tree care facilities (location where vehicles and equipment are housed);:
2. GHG Assessment Boundary: List the GHG sources and sinks that will be included in the GHG Assessment Boundary.

Section 4: Project Eligibility

1. State the expected average annual net number of project tree sites created over the project lifetime (this is the project NTG):
2. State the average annual NTG prior to project commencement (for municipalities and educational campuses only):

3. State the total number of trees prior to the start of the project (for municipalities and educational campuses only):
4. Is any portion of the project activity required by any local, state, regional, or federal regulation? (Y/N)
5. Describe tree planting requirements outside of the project activity that are mandated by law and are planned to be undertaken by the entity:

Section 5: Tree Maintenance Plan

This initial Tree Maintenance Plan constitutes a description of planned maintenance activities. Per Section 9 of the protocol, approved projects must annually submit a Tree Maintenance Plan for each year of project duration, reporting activities ex post. This initial Tree Maintenance Plan must address the following requirements:

1. Document the most recent and anticipated future levels of service and expenditures for all criteria in the Tree Maintenance Plan (for details, see protocol Section 9: Project Monitoring).
2. Describe how project tree planting sites will be identified and prioritized.
3. Provide estimates for tree mortality rates for newly planted and established project trees, and explain how these estimates were derived.
4. Describe how project trees that need replacing will be identified, the timing of replacement, and the species and size of replacement trees.
5. Identify the personnel who will implement and manage the project, their roles and responsibilities, and funds required for salary, operations, training, and overhead over the duration of the project. Other activities that may be included here are public relations, accounting, fund raising, and outreach.

Section 6: Tree Monitoring Plan

Per Section 9.2 of the protocol, the Tree Monitoring Plan must address the following requirements:

Provide a detailed description of:

1. Method chosen from the options in Section 6.1.
2. Procedures that will be used to census, measure, and report information on the project trees, including survey method, sample sizes, and method for choosing samples.
3. Methods that will be used to measure and record tree dimensions.
4. Methods that will be used and information collected on tree survival and health.
5. Statistical methods that will be used to extrapolate sample data to the total project tree population, if applicable.
6. Estimating sampling error, if applicable.

Appendix D Offset Project Data Report

1. Offset Project Operator
2. Project Name
3. Name of Individual Completing the Report
4. Date
5. Verification Period

Section A. Annual Reporting

6. Each Annual Offset Project Data Report must contain the following
    a. Project personnel
    b. Personnel name(s)
    c. Organization and title(s)
    d. Responsibilities

7. Equations and calculations

    a. Project tree volume, biomass, and carbon stocks (for measured trees and for the project tree population, if sampling and extrapolation are used) at project commencement (or renewal) and annually thereafter.

    b. For (a) above, standard error and sampling error at the 90% confidence interval, if applicable.

    c. Amount and type of fuel consumed during project tree maintenance and planting.

    d. Project tree resource: Percentage of total project trees planted.

    e. Net Tree Gain for each year and annual averages (Section 3.4.2) at the level of the municipality or educational campus.

    f. Net Tree Gain for each year at the project level..

    g. Mature tree care
        i. Number of mature project trees inspected/pruned each year.
        ii. Inspection/pruning cycle (total number of project trees / number treated per year).
        iii. Annual expenditure (Reported annually, separately for the project and for the municipality, educational campus, or utility).

    g. Tree removal:

i. Number of trees removed from existing tree sites each year (separately for non-project and project trees).
ii. Species, size, and location[12] of project trees removed each year.
iii. Reasons for removals and, if applicable, modifications made to the project to reduce the chance of future removals.
iv. Removal cycle (total number of project trees to remove / number removed per year).
v. Annual expenditure (separately for the project and for the municipality, educational campus, or utility).

h. Administration/other
i. Average $/tree site expenditure (total $ on admin and other / total tree numbers) (separately for the project and municipality, educational campus, or utility).
ii. Annual expenditure (separately for the project and for the municipality, educational campus, or utility).

8. Project Tree Monitoring Plan (required every year that an offset project data report is subject to verification)
i. Choice of method from the options in Section 6.1.
ii. Detailed description of procedures to census (or sample, if applicable), measure, and report information on the project trees, including the survey method, sample sizes, and method for choosing samples.
iii. Methods used to measure and record tree size.
iv. Methods used and information collected on tree survival and health.
v. Statistical methods used to extrapolate sample data to the total project tree population, if applicable.
vi. Estimated sampling error, if applicable.

9. Equations and calculations, for each year:
i. Project tree carbon stock change over the interval from project commencement (or renewal) through no later than the 6th year, and adjusted carbon stock change, if applicable
ii. Project tree CO_2 sequestration over the interval from project commencement (or renewal) through no later than the 6th year. Report adjusted CO_2 sequestration value, if applicable.
iii. Project vehicle CO_2 emission over the interval from project commencement (or renewal) through no later than the 6th year.
iv. Project equipment CO_2 emission over the interval from project commencement (or renewal) through no later than the 6th year.
v. Project GHG Reduction over the interval from project commencement (or renewal) through no later than the 6th year

10. Calculated project GHG reductions (removal enhancements, by year,:

[12] Tree site location must be designated on a map of the project physical boundaries.

i. Project tree CO_2 sequestration (adjusted for sampling error, if applicable)
ii. Project vehicle CO_2 emissions
iii. Project equipment CO_2 emissions
iv. Project GHG reductions (removal enhancements)

California Environmental Protection Agency

Air Resources Board

Proposed Regulation to Implement the California Cap-and-Trade Program

PART III

STAFF REPORT AND COMPLIANCE OFFSET PROTOCOL

U.S. OZONE DEPLETING SUBSTANCES PROJECTS

Release Date: October 28, 2010

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State of California

California Environmental Protection Agency
AIR RESOURCES BOARD
Office of Climate Change

STAFF REPORT: INITIAL STATEMENT OF REASONS PROPOSED REGULATION TO IMPLEMENT THE CALIFORNIA CAP-AND-TRADE PROGRAM

PART III

STAFF REPORT AND COMPLIANCE OFFSET PROTOCOL

U.S. OZONE DEPLETING SUBSTANCES PROJECTS

Public Hearing to Consider the Proposed Regulation to Implement the California Cap-and-Trade Program

Date of Release: October 28, 2010
Scheduled for Consideration: December 16, 2010

Location:

California Air Resources Board
Byron Sher Auditorium
1001 I Street
Sacramento, California 95814

This report has been reviewed by the staff of the California Air Resources Board and approved for publication. Approval does not signify that the contents necessarily reflect the views and policies of the Air Resources Board, nor does mention of trade names or commercial products constitute endorsement or recommendation for use.

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Compliance Offset Protocol for U.S. Ozone Depleting Substances Projects
Date: October 13, 2010

Staff Report

I. Introduction and Background on Compliance Offset Protocols

A. Staff Proposal

Staff is recommending the Board adopt four compliance offset protocols to support the proposed Cap-and-Trade program. They include a compliance offset protocol for Livestock Manure (digester) projects, Ozone Depleting Substances destruction projects, Urban Forest projects, and Forest Projects. This part discusses the development of a compliance offset protocol for U.S. Ozone Depleting Substances projects.

B. Rationale for Compliance Offset Protocols

The Air Resources Board's (ARB or Board) proposed cap-and-trade program allows the use of offsets, emission reductions from uncapped sectors, to comply with emission reduction obligations. Offset credits are issued from projects developed using ARB-adopted compliance offset protocols. Compliance offset protocols contain the project eligibility criteria to ensure reductions are additional, quantification methodologies and regulatory verification and enforcement requirements, as required by AB32. Therefore, they represent the standard by which offset projects are reviewed and judged. They contain the basic methods and procedures to conduct the offset project and determine the greenhouse gas reduction benefits. AB 32 also requires that offsets be "real, permanent, quantifiable, verifiable, enforceable, and additional."

C. ARB Transition to Compliance Offset Protocol

In order to encourage voluntary actions to reduce greenhouse gas (GHG) emissions, the Board decided to adopt GHG emission reduction project protocols starting in 2007. In October 2007, the Board adopted its first Forest Project Protocol for voluntary purposes, version 2.1 developed by the Climate Action Reserve (CAR). In September 2008, the Board adopted the Livestock Manure Project Protocol version 2.1 and Urban Forest Protocol version 1.0, also for voluntary purposes. Finally in September 2009, the Board adopted the Forest Project Protocol version 3.0, an update to version 2.1 to enable greater participation in forest projects. The Ozone Depleting Substances Project Protocol

version 1.0 was adopted by CAR in early February 2010, and the timing precluded it from being adopted by the Board for voluntary purposes.

The adoption of the protocols represented the Board's endorsement of technically sound approaches for carbon accounting in voluntary projects. Each of these protocols were developed by CAR and taken through an ARB public review process before they were adopted by the Board.

At its February 2010 meeting, the Board requested staff to initiate a public process to transition from protocols for voluntary purposes to development of compliance offset protocols for compliance purposes in the proposed cap-and-trade program. The Board rescinded approval of the voluntary protocols in order to begin the transition to a regulatory compliance offset program. Staff began the process by reviewing updates made to the voluntary protocols since the Board adopted them. On June 23, 2010, ARB staff held a public workshop to discuss the four protocols that were under consideration for modification to align with criteria in AB 32 and the proposed cap-and-trade rule.

D. Compliance Offset Protocol Structure and Regulatory Requirements

Offset protocols consist of two main structural elements, project requirements and project quantification. Project requirements include items such as eligibility, monitoring and reporting, and verification and enforcement provisions. AB 32 requires ARB to adopt regulatory requirements for verification and enforcement of any offset reductions used for compliance purposes. Project quantification identifies the quantification methodologies and equations used in project accounting such as baseline determination and calculation of emissions and emission reductions.

Compliance offset protocols will be incorporated by reference into the proposed cap-and-trade regulation. This incorporation makes the offset protocol document an enforceable regulation. AB 32 exempts quantification methodologies from the Administrative Procedure Act (APA), however those elements of the offset protocol are still regulatory. The exemption allows future updates to the quantification methodologies to be made through a public review and Board adoption process but without the need for rulemaking documents. Each offset protocol identifies sections that are considered quantification and exempt from the APA requirements, Any changes to the non-quantification elements of the offset protocols would be considered a regulatory update subject to the full regulatory development process.

Since the offset protocols will now be used in the context of a compliance program, staff has modified language in the offset protocols to refer to the regulatory requirements in the proposed cap-and-trade regulation where needed rather than splitting the former voluntary protocols into separate documents

based on regulatory requirements and quantification methodologies. In sections where there is a regulatory requirement in the cap-and-trade regulation, staff refers readers to the appropriate section in the rule.

In addition, the proposed cap-and-trade rule includes offset program regulatory requirements, including but not limited to, eligibility criteria for start dates, project locations, offset project reporting periods, project document retention, project listing information, project reporting information, verification requirements, permanence mechanisms for sequestration projects, and enforcement provisions. Where there are regulatory requirements in the cap-and-trade rule, staff has modified language in the offset protocol to align with the rule.

E. Environmental Impacts

The California Environmental Quality Act (CEQA) and ARB policy require an analysis to determine any potentially adverse environmental impacts of any potential projects under the compliance offset program. ARB determined that adoption and implementation of the proposed compliance offset protocols constitute "projects" as defined by Public Resources Code §21000 et seq. The CEQA Guidelines, §15378 provides the definition of a project. ARB has included a tiered environmental review of the proposed cap-and-trade regulation, the offset program, and subsequently adopted compliance offset protocols in the cap-and-trade regulation.

II. U.S. Ozone Depleting Substances (ODS) Protocol

A. Role of Ozone Depleting Substances Destruction in Climate Change Mitigation

Ozone depleting substances are chemicals that destroy the stratospheric ozone layer when released into the atmosphere. The production of these substances is being phased-out under the Montreal Protocol on Substances that Deplete the Ozone Layer. The Montreal Protocol incorporates two different phase-out schedules: one for developing countries listed in Article 5 of the agreement and another, more rapid phase-out, for non-Article 5 countries. Additionally, the U.S. has its own phase-out schedule that addresses the most potent ODS first.

In addition to destroying the ozone layer, ozone depleting substances are thousands of times more potent in trapping heat in the atmosphere than carbon dioxide. Large quantities of ODS (e.g. chloroflurocarbons, hydrochloroflurocarbons, and halons) produced prior to phase-out deadlines under the Montreal Protocol remain legally in use or storage in older equipment, building and appliance insulation, and other "banks." Under business as usual, these banks will ultimately be released to the atmosphere. In 2010, annual

emissions from banks are expected to be over 80 $MMTCO_2E$[1] for the United States. A portion of these emissions can be eliminated through the collection and destruction of these gases.

B. Development of the Compliance Offset U.S. ODS Protocol

The ODS protocol development process was a public process involving a diverse group of stakeholders. CAR set up a protocol development workgroup and solicited applications for participation, selecting approximately 20 members from over 30 applicants. The workgroup members were chosen to achieve a well-balanced and experienced cross-section of stakeholders. The workgroup consisted of representatives from ARB, the World Bank, environmental non-profits, ODS manufacturers, ODS destruction technology experts, government agencies, refrigerant re-claimers, consultants, and other industry stakeholders.

The process started in May of 2009 with a public kick-off workshop in DC. There were two additional public workshops in DC and six official workgroup calls as well as weekly informal subgroup calls on specific issues. Many stakeholders that were unable to participate in the workgroup process submitted comments during the public comment periods. CAR then revised the draft protocol based on the comments. The CAR Board approved the final protocol at a public meeting on February 3rd in Sacramento. Because this protocol was only recently adopted by CAR, the Air Resources Board (ARB or Board) did not have an opportunity to formally adopt this protocol for purposes of voluntary use as it had for other protocols.

Staff presented the U.S. ODS project protocol at a June 23, 2010, workshop to introduce the protocol to stakeholders and address any questions or concerns at that time. Stakeholders were provided an opportunity to provide feedback on the staff's presentation and proposal for moving ahead with the U.S. ODS project protocol.

The WCI Partner jurisdictions are reviewing the Ozone Depleting Substances offset protocol; including assessing it relative to the WCI offset criteria recommendations. Staff will continue to work within WCI to address any potential issues that may arise in the context of linking with a WCI Partner.

C. Description of the Compliance Offset U.S. ODS Protocol

Overview

[1]UNEP, 2009. "Compilation of Strategies for the environmentally sound management of banks of ozone depleting substances" Workshop on management and destruction of ODS banks and implications for,climate change. June 26, 2009. http://ozone.unep.org/Meeting_Documents/workshop_on_ODS_banks/WORKSHOP-3-INF1E.pdf

ARB's proposed compliance offset ODS Project Protocol is based on the Climate Action Reserve's U.S. Ozone Depleting Substances Protocol Version 1.0[2] and includes the information provided in the CAR's Errata and Clarification[3]. The offset protocol is applicable to projects in the United States and its territories.

The offset protocol identifies methods to calculate the greenhouse gas benefits from collecting ODS and transporting and destroying it at an eligible destruction facility. To fit into a statewide, national, and international GHG accounting framework, ODS project accounting must meet recognized and robust standards including the requirements of AB 32. This requires that GHG reductions be real, additional, independently verified, not double-counted, and permanent. The offset protocol is designed to meet these standards and requirements and provide accurate and standardized GHG accounting methods for complete, consistent, transparent, accurate, and conservative accounting GHG emissions and emission reductions associated with ODS projects. The offset protocol also defines eligibility rules, offset project boundaries, provides GHG reduction and emission calculation methods, and identifies procedures for project monitoring, reporting parameters, and verification. All projects must pass the eligibility requirements set forth in this offset protocol and the cap-and-trade regulation to be eligible to register GHG reductions for the duration of the project-crediting period.

Conservative Accounting

The compliance offset protocol incorporates conservative baseline and project assumptions. The baseline emission estimates assume that a percentage of the ODS will be recycled or degraded within a landfill. These end of life assumptions result in lowered credit for each reduction. Likewise the project baseline emission estimates include conservative assumptions. For refrigerants, emissions from substitute refrigerants are considered. For foams, the calculations include losses during the extraction process. For both types of ODS, emissions from transport and energy use are part of the project emissions. Overall, the result is that credit for one ton of reduction is significantly lowered. The default credits range from a low of under 0.20 tonnes of CO2E credit for each tonne of CFC-11 from building insulation to approximately 0.87 tonnes of CO2E credit for each tonne of CFC-12 refrigerant.

Additionality

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[2] CAR (2010) U.S. Ozone Depleting Substances Project Protocol Version 1.0. February 3, 2010. http://www.climateactionreserve.org/how/protocols/adopted/ods/current/ (accessed August 30, 2010)

[3] CAR (2010) U.S. Ozone Depleting Substances Project Protocol Errata and Clarifications. May 7, 2010. http://www.climateactionreserve.org/how/protocols/adopted/ods/current/ (accessed August 30, 2010)

Eligible projects under this offset protocol must result in reductions that are additional to what would have occurred in the absence of the project. The offset protocol ensures additionality utilizing a performance standard approach and a regulatory additionality requirement.

There are significant existing stocks of ODS in equipment or material. For example, ODS exists for years in both refrigerant equipment and in foams in appliances and buildings. For foams, the entrained gas stays in the foam for years, generally until the end of life of the appliance or building. On the other hand, ODS in refrigerant equipment leaks out over time with the leakage rate dependant on the equipment type and maintenance level. As a result of these banks of gases in existing equipment and material, emissions of ODS will continue for decades past the phase-out dates. With the lack of current requirements to limit or eliminate emissions of these gases, most of the banks are expected to be emitted to the atmosphere eventually through leakage or end-of-life practices.

The performance standard is an identified standard of performance applicable to all ODS projects. The purpose of a performance standard is to establish a threshold that is significantly better than average greenhouse gas (GHG) production for a specified activity, which, if met or exceeded by a project developer, satisfies the criterion of "additionality." If the project meets the threshold, then it exceeds what would happen under the business-as-usual scenario and generates surplus/additional GHG reductions. This offset protocol uses a technology-specific threshold; sometimes also referred to as a practice-based threshold, where it serves as "best-practice standard" for managing ozone depleting substances. Eligible ODS are in appliance or building foam or in refrigerant equipment. Data shows that less than 1.5% of recoverable US sourced ODS are destroyed upon end-of-life of the equipment or material. This indicates that collecting and destroying the ODS is above and beyond common practice and therefore destruction meets the performance standard.

In addition to the performance standard, eligible projects must show regulatory additionality, meaning that there are no state or federal regulations or local agency ordinances/rulings requiring the installation of a biogas control system. In addition, projects must comply with all applicable local, state, and national regulations, whether for air and water quality, energy regulations, or others.

The ODS eligible under the compliance offset protocol are limited to foam blowing agents and refrigerants that are being phased out and cannot be produced or imported into the United States for any specified purpose after January 1, 2010. Additionally, the ODS covered by the offset protocol all have high global warming potentials (GWP) from several hundred to several thousand

times that of carbon dioxide. Although production and importation are controlled, use of existing stocks is not controlled and destruction is not required.

This compliance offset protocol does not cover destruction of hydrofluorocarbons (HFCs) or ozone depleting substances that are still being produced in or imported into the United States. In particular, destruction of HFC-23 as a by-product of HCFC-22 production is not counted under this methodology. The HFC-23 credits are controversial because the credits can cause the perverse incentive to increase HCFC-22 production just to produce HFC-23 to be destroyed. ARB's ODS compliance offset protocol avoids that concern by not covering HFCs and only covers banks of ODS whose production and import has been phased out in the United States.

Permanence

GHG reductions resulting from the destruction of ODS are permanent. The offset protocol requires that the facility destroy ODS that would otherwise have been emitted to the atmosphere in the absence of the project.

Quantification Methodologies

The calculation methodologies in the protocol include emissions and emission reductions from ODS transport and destruction. The offset protocol covers direct emissions of ozone depleting substances and carbon dioxide (CO2) associated with the use and disposal of banks of ODS, transport and destruction of ODS, and use of substitute refrigerants. Emission calculations associated with the project include variables such as destruction efficiencies. Quantifying the GHG impact associated with destruction of ODS requires the use of measurements for the most important emissions or reduction points as well as conservative default emission factors for smaller emission sources.

Monitoring, Reporting, and Verification

Project developers are responsible for monitoring the performance of the project and operating the destruction system in a manner consistent with either their RCRA permit or UN TEAP guidelines and the Montreal Protocol Code of Good Housekeeping. Project developers must also collect and record measurement data verifying the composition and quantity of ODS destroyed, in some cases analysis must be done by an independent laboratory unaffiliated with the project developer.

Project developers must report GHG reductions resulting from project activities and submit verified emission reduction reports annually. For transparency, project information will be made publically available.

III. Specific Changes made to CAR's U.S. Ozone Depleting Substances Protocol

The most significant change staff is proposing is to use the global warming potential factors for HFCs from the IPCC Second Assessment Report (SAR) so as not to conflict with GWPs used in the California statewide greenhouse gas inventory. ARB will retain the Fourth Assessment Report (AR4) GWPs for ODS since the SAR does not have GWPs for all ODS and the ODS are not included in the California statewide greenhouse gas inventory. Staff is not proposing any other technical or quantification changes from CAR's Protocol version 1.0 and has incorporated CAR's recent errata and clarifications for this offset protocol.

Broadly, the types of changes made to transition CAR's protocol to an ARB compliance offset protocol included:

- Aligning and clarifying terminology to match ARB regulations, such as project developer versus operator, CRTs versus offset credits, project start date versus project commencement, etc.
- Aligning requirements such as listing and reporting requirements to match Cap and Trade regulations
- Requiring ARB's regulatory verification program for accreditation of verification bodies, verification services, conflict of interest, etc.

The following list provides specific changes made to transition CAR's protocol to an ARB compliance offset protocol:

- Referenced to CAR protocol version 1.0 and removed all other references;
- Removed references specific to CAR and their process, including references to CRT's, CAR attestation forms that ARB does not need to implement the offset protocol, verification requirements, and process for starting a project.
- Some text was removed and replaced with references to the regulatory language. This includes removing the table showing eligibility rule overview language on legal requirements and performance standard, and the project documentation section;
- Modified terminology to be consistent with the regulation.
    - Project developers are now offset project operators or authorized project designees;
    - Project start date changed to project commencement;
    - Project Monitoring and Operation changed to Project Documentation;

  - Record Keeping Section and changed to Document Retention;
  - Updated glossary to reflect regulatory definitions.
- Aligned start date eligibility with ARB regulation and changed project commencement information to be in line with ARB's regulatory process;
- Changed the Reporting period and verification cycle to align with regulation;
- Changed 12 month period for a project to a single calendar year;
- Included annual reporting requirements, project data report requirements and record retention requirements;
- Project listing requirements replaced the project submittal form;
- Changed verification to be in line with regulation and removed language on project developer disclosure of non-compliance to verifier;
- Identified sections that contain non-regulatory quantification methodologies;
- Removed text on non-compliance due to "acts of nature"
- Removed text unrelated to project description, quantification, or implementation.
- Included errata and clarifications where appropriate, including correction to Figure 4.1, correction to last equation in Equation 5.4, revise language in 5.2.2 to clarify recovery efficiency verification, corrected section 6.3,
- Revised Table 5.5 (now Table 5.4) to use Second Assessment Report GWPs for HFCs used as substitutes for ODS;
- Clarified language in Section 5.2.4 on RCRA permit;
- Removed language on successor to AHRI standard as this language is not allowed under California law.

IV. References

CAR (2010) U.S. Ozone Depleting Substances Project Protocol Version 1.0. February 3, 2010.
http://www.climateactionreserve.org/how/protocols/adopted/ods/current/
(accessed August 30, 2010)

CAR (2010) U.S. Ozone Depleting Substances Project Protocol Errata and Clarifications. May 7, 2010.
http://www.climateactionreserve.org/how/protocols/adopted/ods/current/
(accessed August 30, 2010)

California Environmental Protection Agency

AIR RESOURCES BOARD

Compliance Offset Protocol for U.S. Ozone Depleting Substances Projects

Destruction of U.S. Ozone Depleting Substances Banks

Adopted: [INSERT Date of Board Adoption]

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Abbreviations and Acronyms

A/C	Air conditioning
AHRI	Air-Conditioning, Heating and Refrigeration Institute
CAA	Clean Air Act
CEMS	Continuous emissions monitoring system
CFC	Chlorofluorocarbons
CH_4	Methane
CO_2	Carbon dioxide
CPT	Comprehensive Performance Test
DOT	U.S. Department of Transportation
DRE	Destruction and removal efficiency
EPA	United States Environmental Protection Agency
GWP	Global warming potential
HBFC	Hydrobromofluorocarbons
HCFC	Hydrochlorofluorocarbons
HFC	Hydrofluorocarbons
HWC	Hazardous waste combustor
NESHAP	National Emissions Standards for Hazardous Air Pollutants
NIST	National Institute of Standards and Technology
ODS	Ozone depleting substances
PU	Polyurethane
RCRA	Resource Conservation and Recovery Act
Regulation	Cap-and-Trade Regulation, title 17, California Code of

	Regulations, sections 95800 et seq.
Reserve or CAR	Climate Action Reserve
TEAP	Technology & Economic Assessment Panel

1 Introduction

The Compliance Offset Protocol for U.S. Ozone Depleting Substances Projects provides methods to quantify and report greenhouse gas (GHG) emission reductions associated with the destruction of high global warming potential ozone depleting substances (ODS) sourced from and destroyed within the U.S. that would have otherwise been released to the atmosphere. This project category includes ODS used in foam blowing agent and refrigerant applications. All destroyed ODS must be fully documented, chemically analyzed, and destroyed at a qualifying facility to be eligible for crediting under this protocol. All ODS must originate in the United States. The protocol is built off of The Climate Reserve's U.S. Ozone Depleting Substances Protocol Version 1.0[1] and includes the information provided in the Errata and Clarification[2].

ODS offset project operators or authorized project designees must use this protocol to quantify and report GHG reductions. The protocol provides eligibility rules, methods to quantify reductions, project-monitoring instructions, and procedures for reporting offset project data reports. Additionally, all projects must submit to annual, independent verification by ARB-accredited verification bodies. Requirements for verification bodies to verify offset project emissions data reports are provided in the Regulation.

This protocol is designed to ensure the complete, consistent, transparent, accurate, and conservative quantification of GHG emission reductions associated with an ODS destruction project. The protocol is comprised of both non-regulatory quantification methodologies and regulatory program requirements to develop an ODS project and generate compliance offset credits.

AB 32 exempts quantification methodologies from the Administrative Procedure Act (APA)[3], however those elements of the protocol are still regulatory. The exemption allows future updates to the quantification methodologies to be made through a public review and Board adoption process but without the need for rulemaking documents. Each protocol identifies sections that are considered quantification and exempt from APA requirements. Any changes to the non-quantification elements of the offset protocols would be considered a regulatory update subject to the full regulatory development process. Those sections that are considered to be a quantification methodology are clearly indicated in the title of the chapter or subchapter if only a portion of that chapter is considered part of the quantification methodology of the protocol.

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[1] CAR (2010) U.S. Ozone Depleting Substances Project Protocol Version 1.0. February 3, 2010. http://www.climateactionreserve.org/how/protocols/adopted/ods/current/ (accessed August 30, 2010)

[2] CAR (2010) U.S. Ozone Depleting Substances Project Protocol Errata and Clarifications. May 7, 2010. http://www.climateactionreserve.org/how/protocols/adopted/ods/current/ (accessed August 30, 2010)

[3] Health and Safety Code section 38571.

2 The GHG Reduction Project

2.1 Background

The term "ozone depleting substances" refers to a large group of chemicals known to destroy the stratospheric ozone layer when released into the atmosphere. ODS were historically used in a wide variety of applications including refrigerants, foam blowing agents, solvents, and fire suppressants. In addition to their potency as ozone depleting substances, the ODS addressed by this protocol also exhibit high global warming potentials (GWP). The GWP of these ODS range from several hundred to several thousand times that of carbon dioxide (see Table 5.1).

2.2 Project Definition – Quantification Methodology

For the purposes of this protocol, a project is defined as any set of activities undertaken by a single offset project operator or authorized project designee resulting in the destruction of eligible ODS at a single qualifying destruction facility over a 12-month period. Destruction may take place under one or more Certificates of Destruction. Each Certificate of Destruction must document the ODS destroyed. The ODS destroyed may come from a single origin (e.g., one supermarket) or from numerous sources. However, the entire quantity of eligible ODS destroyed must be documented on one or more Certificates of Destruction issued by a qualifying destruction facility.

Although project operators or authorized project designees may engage in ongoing collection and destruction activities, destruction events that fall outside of the single calendar year designated for a project may only be counted as part of a separately registered project. Offset project operators or authorized project designees may choose a shorter time horizon for a single project (e.g., 3 months or 6 months), but no project may run longer than a calendar year.

In order for multiple Certificates of Destruction to be included under a single project, all of the following conditions must be met:

- The offset project operator or authorized project designee of emission reductions are the same for all ODS destroyed
- The qualifying destruction facility is the same for all Certificates of Destruction
- The destruction activities span a timeframe occurring in one calendar year
- No Certificate of Destruction is included as part of another project

For all projects, the end fate of the ODS must be destruction at either an approved Hazardous Waste Combustor (HWC) subject to the Resource Conservation and Recovery Act (RCRA), CAA, and the National Emissions Standards for Hazardous Air Pollutants (NESHAP) standards, or any other transformation or destruction facility that meets or exceeds the Montreal Protocol's Technology & Economic Assessment Panel (TEAP) standards provided in the *Report of the Task Force on Destruction Technologies* and listed in The Climate Reserve's *U.S. Ozone Depleting Substances Protocol Version 1.0*. All facilities must meet any applicable requirements under the CAA and NESHAP. Non-RCRA permitted facilities cannot receive and destroy ODS

materials that are classified as hazardous waste and must demonstrate compliance with the Title VI requirements of the CAA for destruction of ODS, as well as demonstrate destruction and removal efficiency (DRE) of 99.99% and emission levels consistent with the guidelines set forth in the aforementioned TEAP report.

2.3 Eligible ODS – Quantification Methodology

This protocol provides requirements for the accounting of GHG reductions from two general sources of ODS eligible under the project definition:

- **Refrigerants:** a project may collect eligible ODS refrigerant (see Section 2.3.1) from industrial, commercial or residential equipment, systems, and appliances or stockpiles, and destroy it at a qualifying destruction facility.

- **Foams:** a project may extract eligible ODS blowing agent (see Section 2.3.2) from appliance foams and destroy the concentrated ODS foam blowing agent at a qualifying destruction facility; or, a project may destroy intact foam sourced from building insulation at a qualified destruction facility.

A single project may incorporate ODS obtained from one or both of these ODS source categories. Tracking procedures and calculation methodologies differ depending on the source of ODS.

ODS that were produced for, used as, or intended for use as solvents, medical aerosols, or other ODS applications are not eligible.

2.3.1 Refrigerant Sources

This source category consists of ODS material produced prior to the U.S. production phase-out that could legally be sold into the U.S. refrigerant market. The ODS must originate from domestic U.S. supplies; imported refrigerant is not eligible under this protocol.

In the absence of a GHG reduction project, this material may be illegally vented or recovered for re-sale into the refrigerant recharge market. As described in Section 5.1.1, for GHG reduction calculation purposes, this protocol conservatively assumes that the refrigerant would be reclaimed.

Only destruction of the following ODS refrigerants is eligible for crediting under this protocol:

- CFC-11
- CFC-12
- CFC-114
- CFC-115

ODS extracted from a foam source for use in refrigeration equipment is not considered part of this source category, and must instead be considered as a foam source. ODS

sourced from federal government installations or stockpiles is not eligible under this protocol.

Additionally, all refrigerant collection, handling, and destruction must be performed in accordance with the reporting and operation requirements of the Regulation.

2.3.2 Foam Sources

This source category consists of ODS blowing agent entrained in foams that, absent a GHG reduction project, would have been released at end-of-life. The ODS blowing agent must originate from U.S. foam sources; imported foams are not eligible under this protocol.

Only the following ODS foam blowing agents are eligible to generate offset credits under this protocol:

- CFC-11
- CFC-12
- HCFC-22
- HCFC-141b

To be eligible for crediting, the ODS blowing agent must be destroyed in one of two ways:

1. **ODS blowing agent extracted from appliance foam and destroyed.** The ODS blowing agent must be extracted from the foam to a concentrated form prior to destruction. This must be done under negative pressure to ensure that fugitive release of ODS cannot occur. The recovered ODS blowing agent must be collected, stored, and transported in cylinders or other hermetically sealed containers.

2. **Intact foam containing ODS blowing agent from buildings destroyed intact.** When the intact foam is separated from building panels, it must be stored, transported, and destroyed in sealed containers.

All foam collection, handling, extraction, and destruction must be performed in accordance with the reporting and operation requirements in the Regulation.

2.4 Offset Project Operator or Authorized Project Designee

The offset project operator or authorized project designee is responsible for project listing, monitoring, reporting, and verification. The offset project operator or authorized project designee must submit the information in Appendix C to meet the listing requirements in the Regulation. The offset project operator or authorized project designee must have legal authority to implement the offset project.

3 Eligibility Rules

Projects that meet the definition of a GHG reduction project in Section 2.2 must fully satisfy the eligibility rules in the Regulation in order to receive an offset credit.

3.1 Location

For ODS destruction to be eligible as a project under this protocol, all ODS must be sourced from stocks in the United States or its territories and destroyed within the United States or its territories.

3.2 Project Commencement

The project commencement is defined as the date on which destruction activities commence, as documented on a Certificate of Destruction. As stated in the Regulation, projects with commencement dates prior to December 31, 2006 are not eligible under this protocol. Projects may always be submitted for listing prior to their commencement date.

3.3 Project Crediting Period

An ODS project is a discrete series of destruction events over a single calendar year. For the purposes of this protocol, it is assumed that, absent the project, the avoided ODS emissions would have occurred over a longer time horizon.

Under this protocol, the project crediting period is the period of time over which avoided emissions are quantified for the purpose of determining creditable GHG reductions. Specifically, ODS projects will be issued offset credits for the quantity of ODS that would have been released over a ten-year period following a destruction event. At the time the project is verified, offset credits are issued for all ODS emissions avoided by a project over the 10-year crediting period.

3.4 Additionality

The protocol must meet the additionality requirements set out in section 95973(a)(2), and must not be required by or undertaken to comply with any federal, state, or local law or ordinance in the project's jurisdiction. Additionally, the methodology must meet the requirements of the Regulation.

The destruction of ODS by the U.S. government is common practice and considered business-as-usual, and therefore ineligible for crediting under this protocol.

3.5 Regulatory Compliance

As stated in the Regulation, offset project operators or authorized project designees must fulfill all applicable local, regional and national requirements on environment impact assessments that apply based on the offset project location. Projects must also meet any other local, regional, and national requirements that might apply. Projects are not eligible to receive offset credits for GHG reductions that occur as the result of

collection or destruction activities that are not in compliance with regulatory requirements.

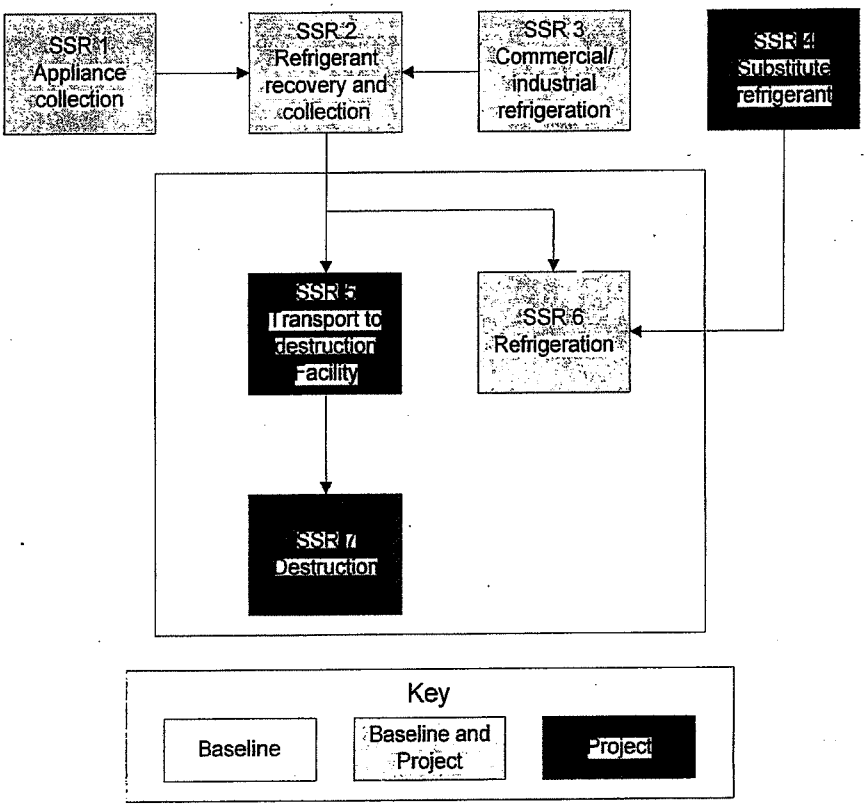
The regulatory compliance requirement extends to the operation of destruction facilities where the ODS is destroyed. Destruction facilities have the potential to contribute to environmental impacts beyond ozone depletion and climate change. Accordingly, all destruction facilities must meet the full burden of applicable regulatory requirements during the time the ODS destruction occurs. Any upsets or exceedences of permitted emission limits must be managed in keeping with an authorized startup, shutdown, and malfunction plan required by EPA (40 CFR 63.1206).

4 The GHG Offset Project Boundary – Quantification Methodology

The GHG Assessment Boundary delineates the GHG sources, sinks, and reservoirs (SSRs) that shall be assessed by project operators or authorized project designees in order to determine the total net change in GHG emissions caused by an ODS project.

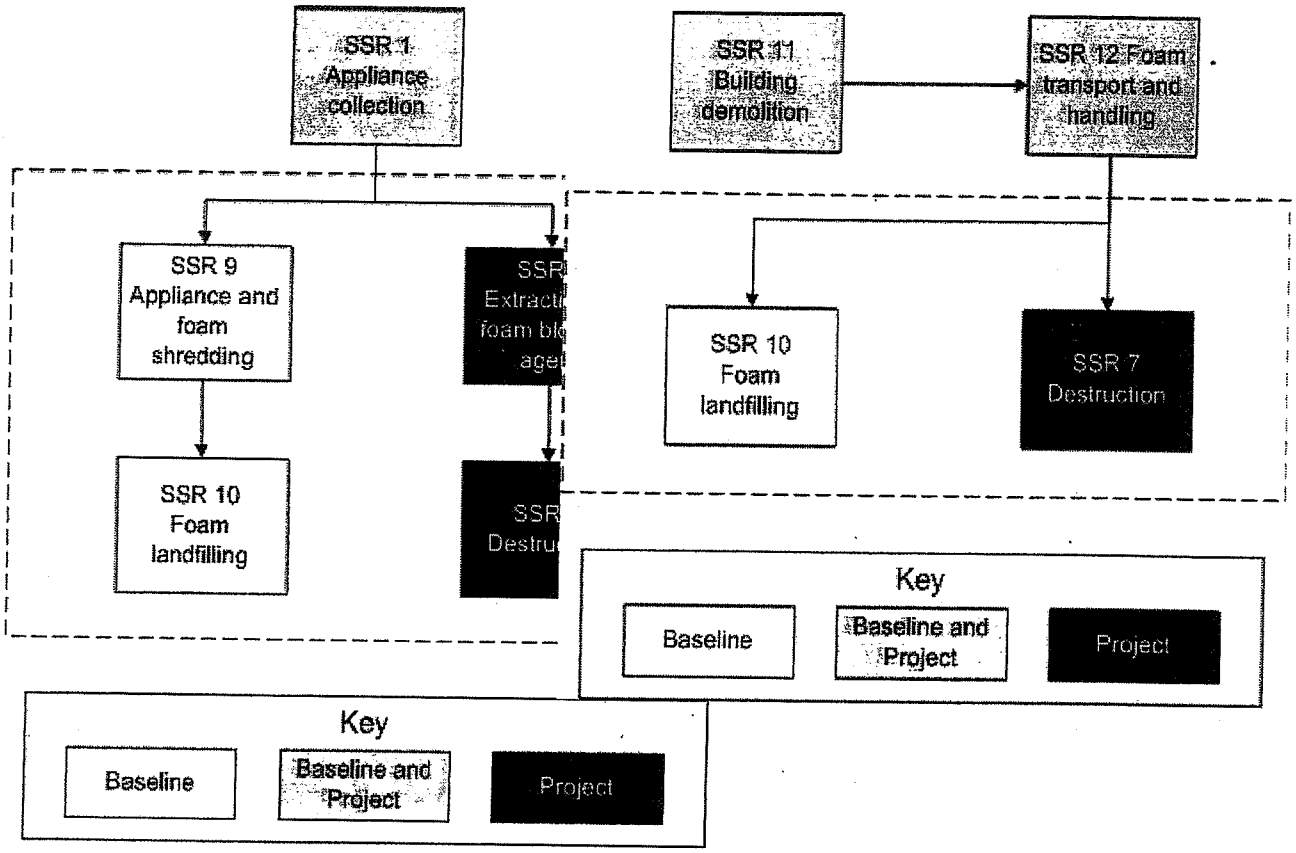
Figure 4.1, Figure 4.2, and Figure 4.3 provide a general illustration of the GHG Assessment Boundaries for different types of ODS destructions projects, indicating which SSRs are included or excluded from the boundary.

Table 4.1 gives greater detail on each SSR and provides information for all SSRs and gases that are excluded from the GHG Assessment Boundary.



Note: Emissions from all sources within the box above are accounted for within this protocol.

Figure 4.1. Illustration of the GHG Assessment Boundary for Refrigerant Projects



Note: Emissions from all sources within the dashed box above are accounted for within this protocol.

Figure 4.2. Illustration of the GHG Assessment Boundary for Appliance Foam Projects

Note: Emissions from all sources within the dashed box above are accounted for within this protocol.

Figure 4.3. Illustration of the GHG Assessment Boundary for Building Foam Projects

Table 4.1. Summary of Identified Sources, Sinks, and Reservoirs – Quantification Methodology

SSR		Source Description	Gas	Included (I) or Excluded (E)	Quantification Method
1	Appliance Collection	Fossil fuel emissions from the collection and transport of end-of-life residential appliances	CO_2	E	N/A
			CH_4	E	N/A
			N_2O	E	N/A
2	Refrigerant Recovery and Collection	Emissions of ODS from the recovery and collection of refrigerant at end-of-life or servicing	ODS	E	N/A
		Fossil fuel emissions from the recovery and collection of refrigerant at end-of-life or servicing	CO_2	E	N/A
			CH_4	E	N/A
			N_2O	E	N/A
3	Commercial/ Industrial Refrigeration	Emissions of ODS from equipment leak and servicing	ODS	E	N/A
		Fossil fuel emissions from the operation of refrigeration and A/C equipment	CO_2	E	N/A
			CH_4	E	N/A
			N_2O	E	N/A
4	Substitute Refrigerant Production	▪ Emissions of substitute refrigerant occurring during production ▪ Fossil fuel emissions from the production of substitute refrigerants	CO_2e	E	N/A
			CO_2	E	N/A
			CH_4	E	N/A
			N_2O	E	N/A
5	Transport to Destruction Facility	Fossil fuel emissions from the vehicular transport of ODS from aggregation point to final destruction facility	CO_2	I	**Baseline:**N/A **Project:** Estimated based on distance and weight transported
			CH_4	E	N/A
			N_2O	E	N/A
6	Refrigeration	Emissions of ODS from leaks and servicing through continued operation of equipment	ODS	I	**Baseline:** Estimated based on market-weighted emission rates **Project:** N/A
		Emissions of substitute from leaks and servicing through continued operation of equipment	CO_2e	I	**Baseline:** N/A **Project:** Estimated based on market-weighted emissions
		Indirect emissions from grid-delivered electricity	CO_2	E	N/A
			CH_4	E	N/A

SSR		Source Description	Gas	Included (I) or Excluded (E)	Quantification Method
			N_2O	E	N/A
7	Destruction	Emissions of ODS from incomplete destruction at destruction facility	ODS	I	**Baseline:** N/A **Project:** Estimated based on ODS destroyed, or included in default deduction
		Emissions from the oxidation of carbon contained in destroyed ODS	CO_2	I	**Baseline:** N/A **Project:** Estimated based on ODS destroyed, or included in default deduction
		Fossil fuel emissions from the destruction of ODS at destruction facility	CO_2	I	**Baseline:** N/A **Project:** Estimated based on ODS destroyed, or included in default deduction
			CH_4	E	N/A
			N_2O	E	N/A
		Indirect emissions from the use of grid-delivered electricity	CO_2	I	**Baseline:** N/A **Project:** Estimated based on ODS destroyed, or included in default deduction
			CH_4	E	N/A
			N_2O	E	N/A
8	Extraction of ODS Blowing Agent from Appliance Foam	Emissions of ODS released during the separation of foam from appliance	ODS	I	**Baseline:** N/A **Project:** Estimated based on recovery efficiency
9	Appliance and Foam Shredding	Emissions of ODS from the shredding of appliances for materials recovery, releasing ODS from foam	ODS	I	**Baseline:** Estimated based on total quantity of ODS destroyed and default shredding factors **Project:** N/A
10	Foam Landfilling	Emissions of ODS released from foam disposed of in landfills	ODS	I	**Baseline:** Estimated based on release and degradation of ODS in landfill **Project:** N/A
		Emissions of ODS degradation products from foam disposed of in landfills	HFC, HCFC	E	N/A

SSR		Source Description	Gas	Included (I) or Excluded (E)	Quantification Method
		Fossil fuel emissions from the transport and placement of shredded foam waste in landfill	CO_2	E	N/A
			CH_4	E	N/A
			N_2O	E	N/A
11	Building Demolition	Emissions of ODS from the demolition of buildings and damage to foam insulation panels	ODS	E	N/A
		Fossil fuel emissions from the demolition of buildings	CO_2	E	N/A
			CH_4	E	N/A
			N_2O	E	N/A
12	Foam transport and handling	Emissions of ODS released from foam during transport and handling	ODS	E	N/A
		Fossil fuel emissions from the transport and handling of building foam	CO_2	E	N/A
			CH_4	E	N/A
			N_2O	E	N/A

5 Quantifying GHG Emission Reductions - Quantification Methodology[4]

GHG emission reductions from an ODS project are quantified by comparing actual project emissions to calculated baseline emissions. Baseline emissions are an estimate of the GHG emissions from sources within the GHG Offset Project Boundary (see Section 4) that would have occurred in the absence of the ODS destruction project. Project emissions are actual GHG emissions that occur at sources within the GHG Offset Project Boundary. Project emissions must be subtracted from the baseline emissions to quantify the project's total net GHG emission reductions (Equation 5.1).

A project may not span more than a single calendar year, although an offset project operator or authorized project designee may choose a shorter time length than 12 months for their project. GHG emission reductions must be quantified and verified at least once for the entire project time length. The quantification methodologies presented below are specified for a single reporting period, which may be less than or equal to the entire project time length.

Equation 5.1. Total Emission Reductions

$$ER_t = BE_t - PE_t$$

Where,

			Units
ER_t	=	Total quantity of emission reductions during the reporting period	tCO_2e
BE_t	=	Total quantity of baseline emissions during the reporting period	tCO_2e
PE_t	=	Total quantity of project emissions during the reporting period	tCO_2e

5.1 Quantifying Baseline Emissions

Total baseline emissions must be estimated by calculating and summing the calculated baseline emissions for all relevant SSRs (as indicated in Table 4.1) using Equation 5.2 and the supporting equations presented below. This includes emissions from continued use of ODS in the secondary recharge market for refrigerants, and the emissions from end-of-life disposal for foams.

Equation 5.2. Total Baseline Emissions

$$BE_t = BE_{refr} + BE_{foam}$$

Where,

			Units
BE	=	Total quantity of baseline emissions	tCO_2e
BE_{refr}	=	Total quantity of baseline emissions from refrigerant ODS	tCO_2e

[4] The entirety of Section 5 is considered a quantification method

BE_{foam}	=	Total quantity of baseline emissions from ODS blowing agent	tCO_2e

Baseline emissions for an ODS destruction project include the total calculated baseline emissions from each eligible source category – ODS refrigerant and ODS blowing agent. If a project does not destroy any ODS from a particular source category, baseline emissions for that source category are assumed to be zero.

Table 5.1 provides the applicable GWP to be used for calculating baseline emissions in units of CO_2-equivalent tonnes.

Table 5.1. Global Warming Potential of Eligible ODS

ODS Species	100-yr Global Warming Potential (CO_2e)
CFC-11	4,750
CFC-12	10,900
CFC-114	10,000
CFC-115	7,370
HCFC-22	1,810
HCFC-141b	725

5.1.1 Calculating Baseline Emissions from Refrigerant Recovery and Resale

To ensure that actual GHG reductions from ODS destruction are not overestimated, this protocol estimates baseline emissions according to the assumption that refrigerant ODS would be entirely recovered and resold.

Equation 5.3 shall be used to estimate the baseline emissions that would have occurred over ten years had the destroyed ODS been used in existing refrigeration or air conditioning equipment. This equation requires the use of the ODS-specific GWP provided in Table 5.1, and emission rate (inclusive of both leak rate and servicing emissions) provided in Table 5.2.

Equation 5.3. Baseline Emissions from Refrigerant ODS

$$BE_{refr} = \sum_i \left(Q_{refr,i} \times ER_{refr,i} \times GWP_i\right)_i$$

Where,

			Units
BE_{refr}	=	Total quantity of refrigerant baseline emissions during the reporting period	tCO_2e
$Q_{refr,i}$	=	Total quantity of refrigerant ODS *i* sent for destruction by the project	tODS
$ER_{refr,i}$	=	10-year cumulative emission rate of refrigerant ODS *i* (see Table 5.2)	%
GWP_i	=	Global warming potential of ODS *i* (see Table 5.1)	tCO_2e/ tODS

Table 5.2. Emission rate for ODS refrigerants

ODS Species	Annual Weighted Average Emission Rate (%/yr)	10-year Cumulative Emission Rate (%/10 years) (ER_{refr})
CFC-11	20%	89%
CFC-12	26%	95%
CFC-114	14%	77%
CFC-115	25%	94%

5.1.2 Calculating Baseline Emissions from Shredding and/or Landfilling ODS Foam Blowing Agents

Depending on the origin of the foam, there are two different predominant baseline practices applicable to foams containing ODS blowing agent. The two baseline practices are as follows:

Origin	Baseline Practice
Insulation foam recovered from appliances	The foam is shredded, and subsequently landfilled
Foam recovered from building demolition	The foam is landfilled

Equation 5.4 shall be used to calculate the ODS emissions that would have resulted from the assumed baseline practice applied to foams in the absence of the project. Baseline emissions include the total emissions that would have occurred as a result of foam shredding and landfilling. In order to calculate total baseline emissions, projects destroying blowing agent extracted from appliance foam must calculate a project-specific recovery efficiency for use in Equation 5.4. Methods for developing the recovery efficiency can be found in Appendix A.

Equation 5.4. Baseline Emissions from ODS Blowing Agent

$$BE_{foam} = \sum_{i,j}\left[\left(BA_{app,i} + BA_{build,i}\right) \times ER_{i,j} \times GWP_i\right]$$

Where,

			Units
BE_{foam}	=	Total quantity of ODS blowing agent baseline emissions	tCO_2e
$BA_{app,i,}$	=	Total quantity of ODS blowing agent *i* from appliance foam prior to treatment or processing, including blowing agent lost during processing	tODS
$BA_{build,i}$	=	Total quantity of ODS blowing agent *i* from building foam sent for destruction	tODS
$ER_{i,j}$	=	Lifetime emission rate of ODS blowing agent *i* from application *j* at end-of-life (see Table 5.3)	%
GWP_i	=	Global warming potential of ODS *i* (see Table 5.1)	tCO_2e/ tODS

$$BA_{app,i} = Q_{recover} + Q_{recover}\left(\frac{1-RE}{RE}\right)$$

Where,

			Units
$BA_{app,i}$	=	Total quantity of ODS foam blowing agent in foam prior to treatment or processing, including ODS foam blowing agent lost during processing	tODS
$Q_{recover}$	=	Total quantity of ODS foam blowing agent recovered during processing and sent for destruction, as determined according to Section 6.5	tODS
RE	=	Recovery efficiency of the ODS foam blowing agent recovery process[5] (See Appendix A for calculation of RE)	%

$$BA_{build} = Q_{foam} \times BA\%$$

Where,

BA_{build}	=	Total quantity of ODS blowing agent *i* from building foam sent for destruction	tODS
Q_{foam}	=	Total weight of foam with entrained ODS blowing agent sent for destruction	tonnes
BA%	=	Mass ratio of ODS blowing agent entrained in building foam, as determined according to Section 6.3	% (0-1)

[5] RE does not extend to the ODS destruction efficiency, which is handled separately under this protocol.

The total percent of ODS foam blowing agent that would be released throughout the end-of-life processing (i.e., 10-year emission rates) for each ODS foam blowing agent and foam origin is presented in Table 5.3. These values include emissions from:

1. ODS blowing agent released during foam shredding,[6] plus
2. ODS blowing agent released during foam compaction, plus
3. Landfilled ODS blowing agent that is released during anaerobic conditions (but is not degraded).

Table 5.3. 10-year Emission Rates of Appliance and Building Foam at End-of-Life

ODS Blowing Agent	Appliance ODS blowing agent 10-year emission rate ($ER_{t,i}$)	Building ODS blowing agent 10-year emission rate ($ER_{t,i}$)
CFC-11	44%	20%
CFC-12	55%	36%
HCFC-22	75%	65%
HCFC-141b	50%	29%

5.2 Quantifying Project Emissions

Project emissions are actual GHG emissions that occur within the GHG Assessment Boundary as a result of project activities.

As shown in Equation 5.5, project emissions equal:

- Emissions from non-ODS substitutes (applicable only to refrigerant projects), plus
- Emissions from ODS foam blowing agent extraction (applicable only to appliance foam projects), plus
- Emissions from the transportation of ODS, plus
- Emissions from the destruction of ODS

Equation 5.5. Total Project Emissions

$$PE_t = Sub_{ref} + BA_{pr} + Tr + Dest$$

Where,

			Units
PE	=	Total quantity of project emissions during the reporting period	tCO_2e
Sub_{ref}	=	Total emissions from substitute refrigerant	tCO_2e
BA_{pr}	=	Total quantity of ODS blowing agent from appliance foam released during ODS extraction	tCO_2e
Tr	=	Total emissions from transportation of ODS (calculated using either the default value in Equation 5.8 or Equation 5.14)	tCO_2e
Dest	=	Total emissions from the process associated with destruction of ODS (calculated using either the default value in Equation 5.8 or Equation 5.9 through Equation 5.13)	tCO_2e

[6] Note that the emissions from foam shredding have only been factored into the emission rates from appliance ODS blowing agents in Table 5.3, as building foam is not typically shredded before being landfilled.

5.2.1 Calculating Project Emissions from the Use of Refrigerant Substitutes

When refrigerant ODS are destroyed, continued demand for refrigeration will lead to the production and consumption of other refrigerant chemicals whose production is still legally allowed. Projects that destroy refrigerant ODS must therefore estimate the emissions associated with the non-ODS substitute chemicals that are assumed to be used in their place. Like the estimates of baseline emissions, substitute emissions shall be accounted for based on the projected emissions over a ten year crediting period.

Project emissions from the use of substitute refrigerants shall be calculated for all ODS refrigerant projects according to Equation 5.6 using the emission factors from Table 5.4. The use of site-specific substitute parameters (refrigerant, GWP, and leak rate) is not permitted.

Equation 5.6. Project Emissions from the Use of Non-ODS Refrigerants

$$Sub_{refr} = \sum_i (Qref_i \times SE_i)$$

Where,

			Units
Sub_{refr}	=	Total quantity of refrigerant substitute emissions	tCO_2e
$Qref_i$	=	Total quantity of refrigerant *i* sent for destruction	t
SE_i	=	Emission factor for substitute(s) for refrigerant *i*, per Table 5.4	tCO_2e/ tODS destroyed

ODS substitute emissions presented in Table 5.4 are based on the weighted average of expected new refrigerant supplies into the refrigeration market. These substitute refrigerants were modeled using the EPA Vintaging Model and data provided by industry sources.

Table 5.4. Refrigerant Substitute Emission Factors[7][8]

ODS Refrigerant	Substitute Emissions (t CO_2e/t ODS) (SE_i)
CFC-11	224
CFC-12	697
CFC-114	659
CFC-115	1570

[7] IPCC (2007). Contribution of Working Group I to the Fourth Assessment Report of the Intergovernmental Panel on Climate Change, 2007. Table 2.14 Errata. Solomon, S., D. Qin, M. Manning, Z. Chen, M. Marquis, K.B. Averyt, M. Tignor and H.L. Miller (eds.)Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA. http://www.ipcc.ch/publications_and_data/ar4/wg1/en/ch2s2-10-2.html

[8] Substitute emissions were developed using a weighted average of 10-year emissions rates in CO_2 equivalent based on the market share, amounts, and leakage rates of the ODS subsitutes. If a substitute is a mix of gases, the GWP for each gas and proportion of each in the mixture is used to determine the GWP of the mixture. The GWPs for the refrigerant substitutes are from the Second Assessment Report, cited in the above footnote.

5.2.2 Calculating Project Emissions from ODS Blowing Agent Extracted from Appliance Foam

Projects that extract ODS blowing agent from appliance foam must account for the emissions of ODS that occur during processing, separation, and extraction using Equation 5.7. These emissions are calculated in Equation 5.7 based on the quantity of ODS blowing agent sent for destruction ($BA_{app,i}$, as calculated in Equation 5.4), and a project-specific recovery efficiency that represents the percentage of ODS that is not lost during these steps. Recovery efficiency must be independently established once for each individual project according to the methods provided in Appendix A.

Equation 5.7. Calculating Project Emissions from the Release of ODS Blowing Agent during Processing

$$BA_{pr} = \sum_{i} \left(BA_{app,i} \times (1 - RE) \times GWP_i \right)$$

Where,			Units
BA_{pr}	=	Total quantity of ODS blowing agent from appliance foam released during ODS extraction	tCO_2e
$BA_{app,i}$	=	Total quantity of appliance ODS foam blowing agent in foam prior to treatment or processing, including ODS foam blowing agent lost during processing (see Equation 5.4 to calculate this term)	tODS
RE	=	Recovery efficiency of the ODS foam blowing agent recovery process (See Appendix A to calculate RE)	%
GWP_i	=	Global warming potential of ODS *i* (see Table 5.1)	tCO_2e/ tODS

5.2.3 Calculating Default Project Emissions from ODS Transportation and Destruction

Projects must account for emissions that result from the transportation and destruction of ODS. Because these emission sources are both individually and in aggregate very small, the protocol default emission factors for ODS projects are based on conservative assumptions and the SSRs outlined in Table 4.1:

- 7.5 tonnes CO_2e per tonne ODS for refrigerant or extracted ODS blowing agent projects
- 75 tonnes CO_2e per tonne ODS for intact building foam projects

These emission factors aggregate both transportation and destruction emissions. Offset Project operators or authorized project designees have the option of using the default emission factors or using the methods in Sections 5.2.4 and 5.2.5 to calculate project-specific emissions.

Equation 5.8 shall be used to calculate ODS transportation and destruction emissions if default emission factors are used. If an offset project operator or authorized project designee elects not to use the default emission factors, emissions associated with transportation and destruction of ODS must be calculated separately.

Equation 5.8. Project Emissions from Transportation and Destruction Using the Default Emission Factors

$$Tr + Dest = \sum_i \left(Q_{ODS,i} \times EF_i\right)$$

Where,

			Units
Tr+Dest	=	Total emissions from ODS transportation and destruction, as calculated using default emission factors	tCO_2e
$Q_{ODS,i}$	=	Total quantity of ODS *i* sent for destruction in the project	tODS
EF_i	=	Default emission factor for transportation and destruction of ODS *i* (7.5 for refrigerant or extracted ODS blowing agent projects, 75 for intact building foam projects)	tCO_2e/ tODS

5.2.4 Calculating Site-Specific Project Emissions from ODS Destruction

Under this protocol, ODS must be destroyed at facilities that have a RCRA permit for hazardous waste destruction or that demonstrate compliance with the TEAP recommendations. These facilities are required to demonstrate their ability to achieve destruction efficiencies upwards of 99.99% for substances with thermal stability ratings higher than the ODS included under this protocol. Associated with the operation of these facilities are emissions of CO_2 from the fuel and electricity used to power the destruction, as well as emissions of undestroyed ODS. Equation 5.9 through Equation 5.11 provide requirements for calculating emissions from ODS destruction in cases where offset project operators or authorized project designees opt not to use the default factors provided in Section 5.2.3.

Equation 5.9. Project Emissions from the Destruction of ODS

$$Dest = FF_{dest} + EL_{dest} + ODS_{emissions} + ODS_{CO2}$$

Where,

			Units
Dest	=	Total emissions from the destruction of ODS	tCO_2e
FF_{dest}	=	Total emissions from fossil fuel used in the destruction facility (Equation 5.10)	tCO_2
EL_{dest}	=	Total indirect emissions from grid electricity used at the destruction facility (Equation 5.11)	tCO_2
$ODS_{emissions}$	=	Total emissions of undestroyed ODS (Equation 5.12)	tCO_2e
ODS_{CO2}	=	Total emissions of CO_2 from ODS oxidation (Equation 5.13)	tCO_2

Equation 5.10. Fossil Fuel Emissions from the Destruction of ODS

$$FF_{dest} = \frac{\sum_k \left(FF_{PR,k} \times EF_{FF,k}\right)}{1000}$$

Where,

			Units
FF_{dest}	=	Total carbon dioxide emissions from the destruction of fossil fuel	tCO_2

		used to destroy ODS	
$FF_{PR,k}$	=	Total fossil fuel *k* used to destroy ODS	volume fossil fuel
$EF_{FF,k}$	=	Fuel specific emission factor (see Appendix B)	kg CO_2/ volume fossil fuel
1000	=	kg/t of CO_2	kgCO_2/ tCO_2

Equation 5.11. Electricity Emissions from the Destruction of ODS

$$EL_{dest} = \frac{(EL_{PR} \times EF_{EL})}{2204.6}$$

Where,

			Units
EL_{dest}	=	Total carbon dioxide emissions from the consumption of electricity from the grid used to destroy ODS	tCO_2
EL_{PR}	=	Total electricity consumed to destroy ODS	MWh
EF_{EL}	=	Carbon emission factor for electricity used (see Appendix B)	lb CO_2/ MWh

Equation 5.12. Calculating Project Emissions from ODS Not Destroyed

$$ODS_{emissions} = \sum_i Q_{ODS,i} \times 0.01\% \times GWP_i$$

Where,

			Units
$ODS_{emissions}$	=	Total emissions of undestroyed ODS	tCO_2e
$Q_{ODS,i}$	=	Total quantity of ODS *i* sent for destruction in the project	tODS
0.01	=	Maximum allowable percent of ODS fed to destruction that is not destroyed	%
GWP_i	=	Global warming potential of ODS *i* (see Table 5.1)	tCO_2e/ tODS

Equation 5.13. Calculating Project Emissions of CO_2 from the Oxidation of ODS

$$ODS_{CO_2} = \sum_i Q_{ODS,i} \times 0.9999 \times CR_i \times \frac{44}{12}$$

Where,

			Units
ODS_{CO2}	=	Total emissions of CO_2 from ODS oxidation	tCO_2
$Q_{ODS,i}$	=	Total quantity of ODS *i* sent for destruction in the project	tODS
0.9999	=	Minimum destruction efficiency of destruction facility	% (0-1)
CR_i	=	Carbon ratio of ODS *i* CFC-11: 12/137 CFC-12: 12/121	mole C/ mole ODS

		CFC-114: 24/187 HCFC-22: 12/87 HCFC-141b: 24/117	
44/12	=	Ratio of CO_2 to C	mole CO_2/ mole C

5.2.5 Calculating Site-Specific Project Emissions from ODS Transportation

As part of any ODS destruction project, ODS will be transported from aggregators to destruction facilities, and emissions from this transportation must be accounted for under this protocol. Equation 5.14 must be used to calculate CO_2 emissions associated with the transport of ODS in cases where offset project operators or authorized project designees choose not to use the default emission factors presented in Section 5.2.3. Emissions shall be calculated for each leg of the transportation process separately, and then summed according to Equation 5.14 below.

Equation 5.14. Calculating Project Emissions from the Transportation of ODS

$$Tr = \sum_i \left(\frac{TMT_i \times EF_{TMT}}{1000} \right)$$

Where,			Units
Tr	=	Total emissions from transportation of ODS	tCO_2e
TMT_i	=	Tonne-miles-traveled[9] for ODS *i* destroyed (to be calculated including the ODS, any accompanying material, and containers from point of aggregation to destruction)	tonne-miles
EF_{TMT}	=	CO_2 emissions per tonne-mile-traveled On-road truck transport = 0.297 Rail transport = 0.0252 Waterborne craft = 0.048 Aircraft = 1.5279	$kgCO_2$ / tonne-mile
1000	=	Conversion from kg to tonnes	kg/tonne

[9] A tonne-mile is defined as the product of the distance travelled in miles and the mass transported in tonnes. Therefore, half a tonne transported four miles is equal to two tonne-miles.

6 Project Documentation Requirements

An ODS destruction project must comply with documentation requirements in the Regulation. The monitoring, reporting, and record retention requirements cover all aspects of this protocol and the documentation must specify how data for all relevant parameters in Table 6.2 was collected and recorded.

Offset project operators or authorized offset project designees are responsible for monitoring the performance of the project and ensuring that there is no double-counting of GHG reductions associated with ODS destruction.

6.1 Point of Origin Documentation Requirements

As in the Regulation, offset project operators or authorized offset project designees are responsible for collecting data on the point of origin of each quantity of ODS as part of tracking chain of custody, as defined in Table 6.1. The offset project operator or authorized project designee must maintain detailed acquisition records of all quantities of ODS destroyed under the project.

Table 6.1. Identification of Point of Origin

ODS	Defined Point of Origin
1. Refrigerant ODS stockpiled for greater than 24 months; or stockpiled prior to the adoption date of this protocol and destroyed within twelve months of the adoption date of this protocol.	Location of stockpile
2. Refrigerant ODS quantities less than 500 lbs	Location where ODS is first aggregated with other ODS to greater than 500 lbs[b]
3. Refrigerant ODS quantities greater than 500 lbs	Site of installation where ODS is removed
4. ODS blowing agent extracted from foam	Facility where ODS blowing agent is extracted
5. ODS blowing agent in building foam	Location of building from which foam was taken

[b] The point of origin for ODS collected by service technicians in individual quantities less than 500 pounds is defined as the holding facility at which several small quantities were combined and exceeded 500 pounds in aggregate. That is, those handling quantities less than 500 pounds need not provide documentation. However, once smaller quantities are aggregated and exceed 500 pounds collectively, tracking will be required from that location and point in time forward.

All data must be generated *at the time of collection* from the point of origin. Documentation of the point of origin of ODS must include the following:

- Facility name and physical address
- Point of origin zip code
- Identification of the system by serial number, if available, or description, location, and function, if serial number is unavailable (for quantities greater than 500 pounds)
- Serial or ID number of containers used for storage and transport

6.2 Chain of Custody Documentation Requirements

In conjunction with establishing the point of origin for each quantity of ODS, offset project operators or authorized project designees must also document the custody and

ownership of ODS beginning from the point of origin as required in the Regulation. These records shall include names, addresses, and contact information of persons/entities buying/selling material for destruction and the quantity of the material (the combined mass of refrigerant and contaminants) bought/sold. Such records may include Purchase Orders, Purchase Agreements, packing lists, bills of lading, lab test results, transfer container information, receiving inspections, freight bills, transactional payment information, and any other type of information that will support previous ownership of the material and the transfer of that ownership. The verifier will review these records and will perform other tests necessary to authenticate the previous owners of the material, the physical transfer of the product, and the title transfer of ownership to the project operator or authorized project designee.

6.3 Building Foam Requirements – Quantification Methodology

The following information shall be collected and recorded related to ODS blowing agents from building insulation foam destroyed by the project:

- Building address
- Date of construction
- Blowing agent used
- Approximate building dimensions

All recovered foam pieces must be placed in air- and water-tight storage for transport to the destruction facility.

ODS blowing agent from building insulation foam may be destroyed intact without extraction of the blowing agent if the following procedures are followed to characterize the mass of foam and type(s) and mass ratio of ODS blowing agent contained in that foam.

1. The mass of the foam shall be determined through weight measurements taken at the destruction facility on scales calibrated quarterly. Scales are considered calibrated if they demonstrate accuracy of +/- 5% of reading.

2. The composition and mass ratio of the ODS foam blowing agent(s) present in the building insulation foam shall be determined based on a selection of a minimum two samples per building surface taken prior to demolition. Accordingly, a building with four exterior walls and a roof would be required to analyze a total of 10 samples: two for each wall, and two for the roof.

3. All samples must be collected and analyzed according to the following requirements:

    - Each foam sample shall be at a minimum 2 inches in length, 2 inches in width, and 2 inches thick

- Each sample shall be placed and sealed in a separate waterproof, air-tight container, that is at minimum 2 millimeters thick for storage and transport
- The analysis of ODS foam blowing agent content and mass ratio shall be done at an independent laboratory unaffiliated with the project operator or authorized project designee
- The analysis shall be done using the heating method to extract ODS foam blowing agent from the foam samples described in Scheutz et al (2007) referenced in The Climate Reserve's U.S. Ozone Depleting Substances Protocol Version 1.0:
    - Each sample shall be prepared to a thickness no greater than 1 cm, placed in a 1123 mL glass bottle, weighed using a calibrated scale, and sealed with Teflon-coated septa and aluminum caps
    - To release the ODS blowing agent from the foam, the samples must be incubated in an oven for 48 hours at 140 degrees C
    - When cooled to room temperature, gas samples must be redrawn from the headspace and analyzed by gas chromatography
    - The lids must be removed after analysis, and the headspace must be flushed with atmospheric air for approximately 5 minutes using a compressor. Afterwards, septa and caps must be replaced and the bottles subjected to a second 48-hr heating step to drive out the remaining ODS blowing agent from the sampled foam
    - When cooled down to room temperature after the second heating step, gas samples must be redrawn from the headspace and analyzed by gas chromatography
- The mass of ODS blowing agent(s) recovered shall then be divided by the total mass of the initial foam samples prior to analysis to determine the mass ratio of each ODS foam blowing agent present

The results from all samples from a single building shall be averaged to determine the mass ratio of blowing agent to foam, and this value multiplied by the weight of destroyed foam. The result shall represent the total quantity of ODS blowing agent from building foams destroyed for that building, and shall be used for the quantity as BA_{build} in Equation 5.4.

These practices shall be documented and must be demonstrated during verification activities.

6.4 Appliance Foam Requirements – Quantification Methodology

The following information shall be collected and recorded related to ODS blowing agent from appliance foams destroyed by the project:

- Number of appliances processed
- Facility at which ODS foam blowing agent is extracted to concentrated form
- Facility at which appliance de-manufacture occurs, if applicable

All appliance foam must be processed to recover and destroy concentrated ODS blowing agent. The following requirements must be met:

- The ODS blowing agent must be extracted from the foam to a concentrated form prior to destruction
- ODS blowing agent must be extracted under negative pressure to ensure that fugitive release of ODS is limited
- The recovered ODS blowing agent must be collected, stored, and transported in containers meeting U.S. Department of Transportation (DOT) standards for refrigerants

Extraction of the foam blowing agent may be performed using any technology capable of recovering concentrated ODS foam blowing agent. The processes, training, QA/QC, and management systems must be documented. The same process must be followed during project implementation and during the calculation of the project-specific recovery efficiency, as described in Appendix A.

Concentrated ODS blowing agent shall be measured according to the procedures provided in Section 6.5.

6.5 Concentrated ODS Composition and Quantity Analysis Requirements – Quantification Methodology

The requirements of this section must be followed to determine the quantities of both ODS refrigerants and concentrated ODS blowing agent. Prior to destruction, the precise mass and composition of ODS to be destroyed must be determined. The following analysis must be conducted:

Mass shall be determined by individually measuring the weight of each container of ODS: (1) when it is full prior to destruction; and (2) after it has been emptied and the contents have been fully purged and destroyed. The mass of ODS and any contaminants is equal to the difference between the full and empty weight, as measured. The following requirements must be met when weighing the containers of ODS:

1. A single scale must be used for generating both the full and empty weight tickets at the destruction facility
2. The scale used must be properly calibrated per the facility's RCRA permit, or for non-RCRA facilities calibrated at least quarterly to an accuracy of within 5% of reading. RCRA facilities that do not have calibration requirements defined in their RCRA permits must calibrate scales quarterly to an accuracy of within 5% of reading.
3. The full weight must be measured no more than two days prior to commencement of destruction per the Certificate of Destruction
4. The empty weight must be measured no more than two days after the conclusion of destruction per the Certificate of Destruction

Composition and concentration of ODS shall be established for each individual container by taking a sample from each container of ODS and having it analyzed for composition and concentration at an Air-Conditioning, Heating and Refrigeration Institute (AHRI) certified laboratory using the AHRI 700-2006 standard as referenced in The Climate Reserve's *U.S. Ozone Depleting Substances Protocol Version 1.0.* The laboratory performing the composition analysis must not be affiliated with the project operator or authorized project designee.

The following requirements must be met for each sample:

1. The sample must be taken while ODS is in the possession of the company that will destroy the ODS
2. Samples must be taken by a technician unaffiliated with the project operator or authorized project designee[10]
3. Samples must be taken with a clean, fully evacuated sample bottle that meets applicable U.S. DOT requirements with a minimum capacity of one pound
4. Each sample must be taken in liquid state
5. A minimum sample size of one pound must be drawn for each sample
6. Each sample must be individually labeled and tracked according to the container from which it was taken, and the following information recorded:
    a) Time and date of sample
    b) Name of operator or authorized project designee
    c) Name of technician taking sample
    d) Employer of technician taking sample
    e) Volume of container from which sample was extracted
    f) Ambient air temperature at time of sampling[11]
7. Chain of custody for each sample from the point of sampling to the AHRI lab must be documented by paper bills of lading or electronic, third-party tracking that includes proof of delivery (e.g., FedEx, UPS)

All project samples shall be analyzed using ARI 700-2006 to confirm the mass percentage and identity of each component of the sample. The analysis shall provide:

1. Identification of the refrigerant
2. Purity (%) of the ODS mixture by weight using gas chromatography
3. Moisture level in parts per million. The moisture content of each sample must be less than 75% of the saturation point for the ODS based on the temperature recorded at the time the sample was taken.
4. Analysis of high boiling residue, which must be less than 10% by mass
5. Analysis of other ODS in the case of mixtures of ODS, and their percentage by mass

[10] For instances where the offset project operator or authorized project designee is the destruction facility itself, an outside technician must be employed for taking samples.

[11] Projects that destroy ODS prior to the adoption date of this protocol may use proxy data from NOAA recording stations in the area.

If any of the requirements above are not met, no GHG reductions may be verified for ODS destruction associated with that container.

If the container holds non-mixed ODS (defined as greater than 90% composition of a single ODS species) no further information or sampling is required to determine the mass and composition of the ODS.

If the container holds mixed ODS, which is defined as less than 90% composition of a single ODS species, the project operator or authorized project designee must meet additional requirements as provided in Section 6.5.1.

6.5.1 Analysis of Mixed ODS

If a container holds mixed ODS, its contents must also be processed and measured for composition and concentration according to the requirements of this section (in addition to the requirements of Section 6.5). The sampling required under this section may be conducted at the final destruction facility or prior to delivery to the destruction facility. However, the circulation and sampling activities must be conducted by a third-party (i.e., not the project operator or authorized project designee), and by individuals who have been properly trained for the functions they perform. Circulation and sampling may be conducted at the project operator or authorized project designee's facility, but all activities must be directed by a properly trained and contracted third-party. The project's documentation must specify the procedures by which mixed ODS are analyzed.

The composition and concentration of ODS on a mass basis must be determined using the results of the analysis of this section for each container. The results of the composition analysis in Section 6.5 shall be used by verifiers to confirm that the destroyed ODS is the same ODS that is sampled under these requirements.

Prior to sampling, the ODS mixture must be circulated in a container that meets all of the following criteria:

1. The container has no solid interior obstructions[12]
2. The container was fully evacuated prior to filling
3. The container must have sampling ports to sample liquid and gas phase ODS
4. The sampling ports must be located in the middle third of the container (i.e., not at one end or the other)
5. The container and associated equipment can circulate the mixture via a closed loop system from the bottom to top

If the original mixed ODS container does not meet these requirements, the mixed ODS must be transferred into a temporary holding tank or container that meets all of the above criteria. The weight of the contents placed into the temporary container shall be calculated and recorded. During transfer of ODS into and out of the temporary

[12] Mesh baffles or other interior structures that do not impede the flow of ODS are acceptable.

container, ODS shall be recovered to the vacuum levels required by the U.S. EPA for that ODS (see 40 CFR 82.156).

Once the mixed ODS is in a container or temporary storage unit that meets the criteria above, circulation of mixed ODS must be conducted as follows:

1. Liquid mixture shall be circulated from the liquid port to the vapor port
2. A volume of the mixture equal to two times the volume in the container shall be circulated
3. Circulation must occur at a rate of at least 30 gallons/minute
4. Start and end times shall be recorded

Within 30 minutes of the completion of circulation, a minimum of two samples shall be taken from the bottom liquid port according to the procedures in Section 6.5. Both samples shall be analyzed at an AHRI approved laboratory per the requirements of Section 6.5. The analysis will determine the GWP weighted concentrations for both samples. The offset project operators or authorized project designees will use the results with the lesser GWP-weighted concentration for the protocol.

6.6 Destruction Facility Requirements – Quantification Methodology

Destruction of ODS must occur at a facility that meets all of the aforementioned TEAP requirements. This includes any RCRA-permitted HWC as well as any other facility that meets the aforementioned TEAP requirements. Facilities permitted as RCRA HWCs are considered to meet the guidelines by default; no further testing for TEAP compliance is required.

At the time of ODS destruction, all destruction facilities must have a valid Title V air permit, if applicable, and any other air or water permits required by local, state, or federal law to destroy ODS. Facilities must document compliance with all monitoring and operational requirements associated with the destruction of ODS materials, as dictated by these permits, including emission limits, calibration schedules, and training. Any upsets or exceedences must be managed in keeping with an authorized start-up, shutdown, and malfunction plan. Non-RCRA facilities must further document operation consistent with the TEAP requirements.

Operating parameters during destruction of ODS material shall be monitored and recorded as described in the Code of Good Housekeeping approved by the Montreal Protocol. This data will be used in the verification process to demonstrate that during the destruction process, the destruction unit was operating similarly to the period in which the DRE[13] was calculated. The DRE is determined using the Comprehensive Performance Test (CPT)[14] as a proxy for DRE and is disclosed to the public in the destruction facility's Title V operating permit.

[13] DRE disclosed in Title V operating permit.
[14] CPT must have been conducted with a less combustible chemical than the ODS in question.

To monitor that the destruction facility operates in accordance with applicable regulations and within the parameters recorded during DRE testing, the following parameters must be tracked continuously during the entire ODS destruction process:

- The ODS feed rate
- The amount and type of consumables used in the process (not required if default project emission factor for transportation and destruction is used)
- The amount of electricity and amount and type of fuel consumed by the destruction unit (not required if default project emission factor for transportation and destruction is used)
- Operating temperature and pressure of the destruction unit during ODS destruction
- Effluent discharges measured in terms of water and pH levels
- Continuous emissions monitoring system (CEMS) data on the emissions of carbon monoxide during ODS destruction

The offset project operator or authorized project designee must maintain records of all of these parameters for review during the verification process.

Destruction facilities shall provide valid Certificate(s) of Destruction for all ODS destroyed as part of the project. The Certificate of Destruction shall include:

- Offset Project operator or authorized project designee
- Destruction facility
- Generator name
- Certificate of Destruction ID number
- Serial, tracking, or ID number of all containers for which ODS destruction occurred
- Weight and type of material destroyed from each container
- Start destruction date
- Ending destruction date

6.7 Monitoring Parameters – Quantification Methodology

Prescribed monitoring parameters necessary to calculate baseline and project emissions are provided in Table 6.2. In addition to the parameters below that are used in the calculations provided in Section 5, offset project operators or authorized project designees are responsible for maintaining all records required under Sections 6 and 7 as required in the Regulation.

Table 6.2. ODS Project Monitoring Parameters – Quantification Methodology

Eq. #	Parameter	Description	Data Unit	Measurement Frequency	Calculated (c) Measured (m) Reference (r) Operating records (o)	Comment
		Legal Requirement Test	N/A	For each project		Must be monitored and determined for each project
		Mass of ODS (or ODS mixture) in each container	mass of mixture	Per container	M	Must be determined for each container
		Concentration of ODS (or ODS mixture) in each container	mass ODS/ mass of mixture	Per container	M	Must be determined for each container
Equation 5.1	ER_t	Total quantity of emission reductions during the reporting period	tCO_2e	For each project	C	
Equation 5.1, Equation 5.2	BE_t	Total quantity of baseline emissions during the reporting period	tCO_2e	For each project	C	
Equation 5.1, Equation 5.5	PE_t	Total quantity of project emissions during the reporting period	tCO_2e	For each project	C	
Equation 5.2, Equation 5.3	BE_{refr}	Total quantity of baseline emissions from refrigerant ODS	tCO_2e	For each project	C	
Equation 5.2, Equation 5.4	BE_{foam}	Total quantity of baseline emissions from ODS blowing agent	tCO_2e	For each project	C	
Equation 5.3, Equation 5.6	$Q_{refr,i}$	Total quantity of refrigerant ODS *i* sent for destruction	tODS	For each project	M	
Equation 5.3	$ER_{refr,i}$	10-year cumulative emission rate of refrigerant ODS *i*	0 - 1.0	N/A	R	See Table 5.1
Equation 5.3, Equation 5.4, Equation 5.7, Equation 5.12	GWP_i	Global warming potential of ODS *i*	tCO_2e/ tODS	N/A	R	See Table 5.1

Eq. #	Parameter	Description	Data Unit	Measurement Frequency	Calculated (c) Measured (m) Reference (r) Operating records (o)	Comment
Equation 5.4, Equation 5.7	$BA_{app,i,}$	Total quantity of ODS blowing agent *i* from appliance foam prior to treatment or processing, including blowing agent lost during processing	tODS	For each project	C	
Equation 5.4	$BA_{build,i}$	Total quantity of ODS blowing agent *i* from building foam sent for destruction.	tODS	For each project	C	
Equation 5.4	$ER_{i,j}$	Lifetime emission rate of ODS blowing agent *i* from application *j* at end-of-life (see Table 5.3)	% (0-1)	N/A	R	
Equation 5.4	$Q_{recover}$	Total quantity of ODS foam blowing agent recovered during processing and sent for destruction	tODS	For each project	M	
Equation 5.4, Equation 5.7	RE	Recovery efficiency of the ODS foam blowing agent recovery process	% (0-1)	Once for each project	C	See Appendix A for calculation of RE
Equation 5.4	Q_{foam}	Total weight of foam with entrained ODS blowing agent sent for destruction	tonnes	For each project	M	
Equation 5.4	BA%	Mass ratio of ODS blowing agent entrained in building foam, as determined according to Section 6.3	% (0-1)	For each project	M	
Equation 5.5, Equation 5.6	Sub_{refr}	Total emissions from substitute refrigerant	tCO_2e	For each project	C	
Equation 5.5, Equation 5.7	$BA_{pr,i}$	Total quantity of ODS foam blowing agent *i* from appliance foam released during ODS extraction	tCO_2e	For each project	C	

Eq. #	Parameter	Description	Data Unit	Measurement Frequency	Calculated (c) Measured (m) Reference (r) Operating records (o)	Comment
Equation 5.5, Equation 5.8, Equation 5.14	Tr	Total emissions from transportation of ODS	tCO_2e	For each project	C	
Equation 5.5, Equation 5.8, Equation 5.9	Dest	Total emissions from the destruction process associated with destruction of ODS	tCO_2e	For each project	C	
Equation 5.6	SE_i	Emission factor for substitute emissions of refrigerant *i*, per	tCO_2e/ tODS destroyed	Per container	R	See Table 5.4 (see 10 for summary of the development of SE)
Equation 5.8, Equation 5.12, Equation 5.13	$Q_{ODS,i}$	Total quantity of ODS *i* sent for destruction	tODS	For each project	M	
Equation 5.8,	EF_i	Default emission factor for transportation and destruction of ODS *i*	tCO_2e/ tODS	N/A	R	Equal to 7.5 for refrigerant projects, and 75 for foam projects
Equation 5.9, Equation 5.10	FF_{dest}	Total emissions from fossil fuel used in the destruction facility	tCO_2e	For each project	C	Use only if calculating site-specific project emissions from ODS destruction
Equation 5.9, Equation 5.11	EL_{dest}	Total emissions from grid electricity at the destruction facility	tCO_2e	For each project	C	Use only if calculating site-specific project emissions from ODS destruction
Equation 5.10	$FF_{PR,k}$	Total fossil fuel *k* used to destroy ODS	tCO_2e	For each project	M	Use only if calculating site-specific project emissions from ODS destruction
Equation 5.10	$EF_{FF,k}$	Fuel specific emission factor	$kgCO_2$/ volume fuel	N/A	R	Use only if calculating site-specific project emissions from ODS destruction
Equation 5.11	EL_{PR}	Total electricity consumed to destroy ODS	MWh	For each project	M	Use only if calculating site-specific project emissions from ODS destruction
Equation 5.11	EF_{EL}	Carbon emission factor for electricity used	$lbCO_2$/ MWh	N/A	R	Use only if calculating site-specific project emissions from ODS destruction

Eq. #	Parameter	Description	Data Unit	Measurement Frequency	Calculated (c) Measured (m) Reference (r) Operating records (o)	Comment
Equation 5.9, Equation 5.12	$ODS_{emissions}$	Total emissions of un-destroyed ODS	tCO_2e	For each project	C	Use only if calculating site-specific project emissions from ODS destruction
Equation 5.9, Equation 5.13	ODS_{CO2}	Total emissions of CO_2 from ODS oxidation	tCO_2	For each project	C	Use only if calculating site-specific project emissions from ODS destruction
Equation 5.13	CR_i	Carbon ratio of ODS *i*	mole C/ mole ODS	N/A	R	Use only if calculating site-specific project emissions from ODS destruction
Equation 5.14	TMT_i	Tonne-miles-traveled for ODS *i* destroyed	tonne-miles	For each project	M	Use only if calculating site-specific project emissions from ODS transportation
Equation 5.14	EF_{TMT}	Mode-specific emission factor	$kgCO_2$/ tonne-mile	N/A	R	Use only if calculating site-specific project emissions from ODS transportation

7 Reporting Parameters

This section provides requirements on reporting rules and procedures. A priority is to facilitate consistent and transparent information disclosure by offset project operators or authorized project designees.

7.1 Annual Reporting Requirements

Offset project operators or authorized project designees must report information contained in Appendix D.

7.2 Document Retention

Project operators or authorized project designees are required to keep all information outlined in the Regulation and this protocol. Records must be retained for a period of 5 years after the end of the crediting period.

System information the project operator or authorized project designee should retain includes, but is not limited to:

- All data inputs for the calculation of the project emission reductions, including all required sampled data
- Copies of all permits, Notices of Violations (NOVs), and any relevant administrative or legal consent orders dating back at least 3 years prior to the project commencement date
- Destruction facility monitor information (CEMS data, DRE documentation, scale readings, calibration procedures, and permits)
- Chain of custody and point of origin documentation
- ODS composition and quantity lab reports

See section 95976 for regulatory record-keeping requirements.

7.3 Reporting Period & Verification Cycle

Project operators or authorized project designees must submit an offset project data report to ARB or an Offset Project Registry annually and be based on a single calendar year, as stated in the Regulation.

Project verification schedules can also be found in the Regulation. A verification statement must be received by October 1 of the next calendar year for which the statement is verifying destruction.

8 Regulatory Verification Requirements

All offset project data reports are subject to regulatory verification as set forth in the Regulation by an ARB accredited verification body. The offset project data report must receive a positive or qualified positive verification statement to be issued compliance offset credits.

9 Glossary of Terms

Certificate of Destruction	An official document provided by the destruction facility certifying the date, quantity, and type of ODS destroyed.
Project commencement	The date of the beginning of the destruction activity.
Commercial refrigeration equipment	The refrigeration appliances used in the retail food, cold storage warehouse or any other sector that requires cold storage. Retail food includes the refrigeration equipment found in supermarkets, grocery and convenience stores, restaurants, and other food service establishments. Cold storage includes the refrigeration equipment used to house perishable goods or any manufactured product requiring refrigerated storage.
Container	An air- and water-tight unit for storing and/or transporting ODS material without leakage or escape of ODS.
Destruction	Destruction of ozone depleting substances by qualified destruction, transformation or conversion plants achieving greater than 99.99% destruction and removal efficiency, in order to avoid their emissions. Destruction may be performed using any technology, including transformation, that results in the complete breakdown of the ODS into either a waste or usable by-product.
Destruction facility	A facility that destroys, transforms or converts ozone depleting substances using a technology that meets the standards defined by the UN Environment Programme Technology and Economic Assessment Panel Task Force on Destruction Technologies as provided in the *Report of the Task Force on Destruction Technologies* and listed in The Climate Reserve's *U.S. Ozone Depleting Substances Protocol Version 1.0.*

Emission rate	The rate at which refrigerant is lost to the atmosphere, including emissions from leaks during operation and servicing events.
Ozone Depleting Substances (ODS)	Ozone depleting substances are substances known to deplete the stratospheric ozone layer. The ODS controlled under the Montreal Protocol and its Amendments are chlorofluorocarbons (CFC), hydrochlorofluorocarbons (HCFC), halons, methyl bromide (CH_3Br), carbon tetrachloride (CCl_4), methyl chloroform (CH_3CCl_3), hydrobromofluorocarbons (HBFC) and bromochloromethane (CHBrCl).
Recovery efficiency	The percent of total ODS blowing agent that is recovered during the process of ODS blowing agent extraction.
Recharge	Replenishment of refrigerant agent (using reclaimed or virgin material) into equipment that is below its full capacity because of leakage or because it has been evacuated for servicing or other maintenance.
Reclaim	Reprocessing and upgrading of a recovered ozone depleting substance through mechanisms such as filtering, drying, distillation and chemical treatment in order to restore the ODS to a specified standard of performance. Chemical analysis is required to determine that appropriate product specifications are met. Reclaiming and the associated chemical analysis often involve processing off-site at a central facility.
Recovery	The removal of ozone depleting substances from machinery, equipment, containment vessels, etc., during servicing or prior to disposal without testing or processing it in any way.
Reuse/recycle	Reuse of a recovered ozone depleting substance following a basic cleaning process such as filtering and drying. For refrigerants, recycling normally involves recharge back into equipment and it often occurs 'on-site'.
Startup, shutdown, and malfunction plan	A plan, as specified under 40 CFR 63.1206, that includes a description of potential causes of

	malfunctions, including releases from emergency safety vents, that may result in significant releases of hazardous air pollutants, and actions the source is taking to minimize the frequency and severity of those malfunctions.
Stockpile	ODS stored for future use or disposal in bulk quantities at a single location. These quantities may be composed of many small containers or a single large container.
Substitute refrigerant	Those refrigerants that will be used to fulfill the function that would have been filled by the destroyed ODS refrigerants. These refrigerants may be drop-in replacements used in equipment that previously used the type of ODS destroyed or may be used in new equipment that fulfills the same market function.
Substitute emissions	A term used in this protocol to describe the greenhouse gases emitted from the use of substitute refrigerants in technologies that are used to replace the ODS destroyed in a project.
Transportation system	A term used to encompass the entirety of the system that moves the ODS from the point of aggregation to the destruction facility.

10 References

CAR (2010) U.S. Ozone Depleting Substances Project Protocol Version 1.0. February 3, 2010.
http://www.climateactionreserve.org/how/protocols/adopted/ods/current/ (accessed August 30, 2010)

CAR (2010) U.S. Ozone Depleting Substances Project Protocol Errata and Clarifications. May 7, 2010.
http://www.climateactionreserve.org/how/protocols/adopted/ods/current/ (accessed August 30, 2010)

Appendix A Foam Recovery Efficiency and Calculations – Quantification Methodology

The following methodology calculates the site- or process-specific recovery efficiency for blowing agent recovery projects, and uses this value for calculation of emission reductions in Section 5. Determination of accurate recovery efficiency allows baseline emissions and project emissions to be calculated in reference to the initial quantity of foam blowing agent diverted from baseline treatment.

A.1 Calculating Recovery Efficiency

All appliance foam projects must calculate a recovery efficiency based on a run of a minimum ten appliances. Basing this analysis on a number of appliances greater than ten will likely result in a higher calculated recovery efficiency due to the 90% upper confidence limit used for calculating the concentration of ODS blowing agent in the foam. A larger sample size will decrease uncertainty and thus lower the estimated blowing agent concentration and increase recovery efficiency; however, sampling of additional appliances will also increase testing costs.

The procedures below shall be used to calculate recovery efficiency.

Estimate initial blowing agent concentration

The concentration of ODS blowing agent in the PU foam prior to any appliance treatment shall either be assumed to equal to 14.9% or calculated according to the steps below. Calculating a sample-specific value allows project operators or authorized project designees to document a lower ODS blowing agent concentration, which will result in a higher estimated recovery efficiency.

The following steps shall be followed to document a sample-specific ODS blowing agent concentration:

1. Cut four PU foam samples from each appliance (left side, right side, top, bottom) using a reciprocating saw. Samples must be at least four inches square and the full thickness of the insulation.
2. Seal the cut edges of each foam sample using aluminum tape or similar product that prevents off-gassing.
3. Individually label each sample to record appliance model, and site of sample (left, right, top, or bottom)
4. Analyze samples according to the procedures dictated for building foam in Section 6.3. Samples may be analyzed individually (four analyses per appliance), or a single analysis may be done using equal masses of foam from each sample (one analysis per appliance).
5. Based on the average of the samples for each appliance, calculate the 90% upper confidence limit of the concentration. The 90% upper confidence limit shall be used as the parameter BA_{conc} in the equations below.

Extract the ODS blowing agent and separate foam residual

The ODS blowing agent from the sampled appliances must be collected and quantified according to the steps below.

1. Begin processing with all equipment shut down and emptied of all materials.
2. Process all sample appliances.
3. Extract and collect concentrated BA. The mass of the recovered blowing agent shall be determined by comparison of the mass of the fully evacuated receiving containers to their mass when filled. This value shall be used as the parameter BA_{post} in the equations below.

Separate foam residual

The quantity of foam in the processed appliances must be established either through use of a default value of 12.9 pounds per appliance, or according to the following steps. If the value of 12.9 pounds per appliance is used, it shall be multiplied by the number of appliances processed to determine $Foam_{res}$ in the calculation of recovery efficiency.

1. Separate and collect all foam residual, which may be in a fluff, powder, or pelletized form. Processes must be documented to demonstrate that no significant quantity of foam residual is lost in the air or other waste streams.
2. If desired, manually separate non-foam components in the residual (e.g., plastic) to determine a percent of foam in residual. If performed, this analysis must be conducted on at least one kilogram of residual, and results may be no lower than 90%.
3. Weigh the total recovered foam residual, and, if performed, multiply by the percent foam in residual, to calculate total mass of foam recovered. This value shall be used as the parameter $Foam_{res}$.

Calculate recovery efficiency

To calculate the recovery efficiency, apply the calculated values to the equations below. The recovery efficiency (RE) calculated below shall be used in the calculations of Section 5.

$$BA_{init} = \frac{Foam_{res}}{(1 - BA_{conc})} \times BA_{conc}$$

Where,			Units
$Foam_{res}$	=	Mass of foam recovered	lbs foam
BA_{conc}	=	Initial concentration of blowing agent in PU foam	lbs BA / lbs PU
BA_{init}	=	Initial quantity of blowing agent in appliances prior to treatment	lbs BA

$$RE = \frac{BA_{post}}{BA_{init}}$$

Where,			Units
RE	=	Recovery efficiency	%
BA_{post}	=	Quantity of recovered blowing agent in concentrated form	lbs BA
BA_{init}	=	Initial quantity of blowing agent in appliances prior to treatment	lbs BA

Appendix B Emission Factor Tables

Table B.1. CO_2 Emission Factors for Fossil Fuel Use

Fuel Type	Heat Content	Carbon Content (Per Unit Energy)	Fraction Oxidized	CO_2 Emission Factor (Per Unit Energy)	CO_2 Emission Factor (Per Unit Mass or Volume)
Coal and Coke	**MMBtu / Short ton**	**kg C / MMBtu**		**kg CO_2 / MMBtu**	**kg CO_2 / Short ton**
Anthracite Coal	25.09	28.26	1.00	103.62	2,599.83
Bituminous Coal	24.93	25.49	1.00	93.46	2,330.04
Sub-bituminous Coal	17.25	26.48	1.00	97.09	1,674.86
Lignite	14.21	26.30	1.00	96.43	1,370.32
Unspecified (Residential/ Commercial)	22.05	26.00	1.00	95.33	2,102.29
Unspecified (Industrial Coking)	26.27	25.56	1.00	93.72	2,462.12
Unspecified (Other Industrial)	22.05	25.63	1.00	93.98	2,072.19
Unspecified (Electric Utility)	19.95	25.76	1.00	94.45	1,884.53
Coke	24.80	31.00	1.00	113.67	2,818.93
Natural Gas (By Heat Content)	**Btu / Standard cubic foot**	**kg C / MMBtu**		**kg CO_2 / MMBtu**	**kg CO_2 / Standard cub. ft.**
975 to 1,000 Btu / Std cubic foot	975 – 1,000	14.73	1.00	54.01	Varies
1,000 to 1,025 Btu / Std cubic foot	1,000 – 1,025	14.43	1.00	52.91	Varies
1,025 to 1,050 Btu / Std cubic foot	1,025 – 1,050	14.47	1.00	53.06	Varies
1,050 to 1,075 Btu / Std cubic foot	1,050 – 1,075	14.58	1.00	53.46	Varies
1,075 to 1,100 Btu / Std cubic foot	1,075 – 1,100	14.65	1.00	53.72	Varies
Greater than 1,100 Btu / Std cubic foot	> 1,100	14.92	1.00	54.71	Varies
Weighted U.S. Average	1,029	14.47	1.00	53.06	0.0546
Petroleum Products	**MMBtu / Barrel**	**kg C / MMBtu**		**kg CO_2 / MMBtu**	**kg CO_2 / gallon**
Asphalt & Road Oil	6.636	20.62	1.00	75.61	11.95
Aviation Gasoline	5.048	18.87	1.00	69.19	8.32
Distillate Fuel Oil (#1, 2 & 4)	5.825	19.95	1.00	73.15	10.15
Jet Fuel	5.670	19.33	1.00	70.88	9.57
Kerosene	5.670	19.72	1.00	72.31	9.76
LPG (average for fuel use)	3.849	17.23	1.00	63.16	5.79
Propane	3.824	17.20	1.00	63.07	5.74
Ethane	2.916	16.25	1.00	59.58	4.14
Isobutene	4.162	17.75	1.00	65.08	6.45
n-Butane	4.328	17.72	1.00	64.97	6.70
Lubricants	6.065	20.24	1.00	74.21	10.72
Motor Gasoline	5.218	19.33	1.00	70.88	8.81
Residual Fuel Oil (#5 & 6)	6.287	21.49	1.00	78.80	11.80
Crude Oil	5.800	20.33	1.00	74.54	10.29
Naphtha (<401 deg. F)	5.248	18.14	1.00	66.51	8.31
Natural Gasoline	4.620	18.24	1.00	66.88	7.36
Other Oil (>401 deg. F)	5.825	19.95	1.00	73.15	10.15
Pentanes Plus	4.620	18.24	1.00	66.88	7.36
Petrochemical Feedstocks	5.428	19.37	1.00	71.02	9.18
Petroleum Coke	6.024	27.85	1.00	102.12	14.65
Still Gas	6.000	17.51	1.00	64.20	9.17
Special Naphtha	5.248	19.86	1.00	72.82	9.10
Unfinished Oils	5.825	20.33	1.00	74.54	10.34
Waxes	5.537	19.81	1.00	72.64	9.58

Default CO_2 emission factors (per unit energy) are calculated as: Carbon Content × Fraction Oxidized × 44/12.
Default CO_2 emission factors (per unit mass or volume) are calculated as: Heat Content x Carbon Content × Fraction Oxidized × 44/12× Conversion Factor (if applicable).
Heat content factors are based on higher heating values (HHV).

Table B.2. CO_2 Electricity Emission Factors

eGRID subregion acronym	eGRID subregion name	Annual output emission rates	
		(lb CO_2/MWh)	(metric ton CO_2/MWh)*
AKGD	ASCC Alaska Grid	1,232.36	0.559
AKMS	ASCC Miscellaneous	498.86	0.226
AZNM	WECC Southwest	1,311.05	0.595
CAMX	WECC California	724.12	0.328
ERCT	ERCOT All	1,324.35	0.601
FRCC	FRCC All	1,318.57	0.598
HIMS	HICC Miscellaneous	1,514.92	0.687
HIOA	HICC Oahu	1,811.98	0.822
MROE	MRO East	1,834.72	0.832
MROW	MRO West	1,821.84	0.826
NEWE	NPCC New England	927.68	0.421
NWPP	WECC Northwest	902.24	0.409
NYCW	NPCC NYC/Westchester	815.45	0.370
NYLI	NPCC Long Island	1,536.80	0.697
NYUP	NPCC Upstate NY	720.80	0.327
RFCE	RFC East	1,139.07	0.517
RFCM	RFC Michigan	1,563.28	0.709
RFCW	RFC West	1,537.82	0.698
RMPA	WECC Rockies	1,883.08	0.854
SPNO	SPP North	1,960.94	0.889
SPSO	SPP South	1,658.14	0.752
SRMV	SERC Mississippi Valley	1,019.74	0.463
SRMW	SERC Midwest	1,830.51	0.830
SRSO	SERC South	1,489.54	0.676
SRTV	SERC Tennessee Valley	1,510.44	0.685
SRVC	SERC Virginia/Carolina	1,134.88	0.515

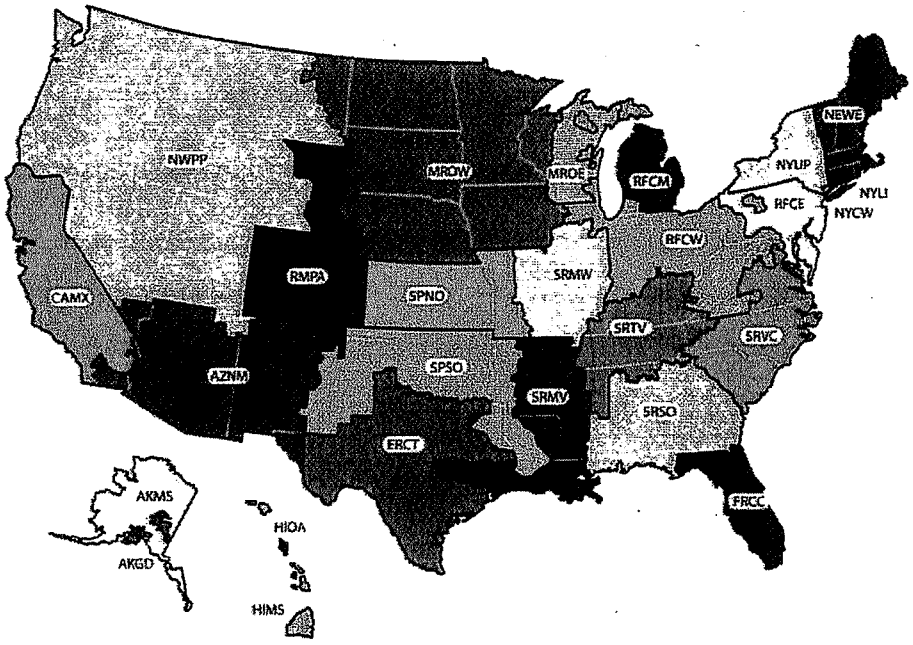


Figure B.1. Map of eGRID2007 Subregions

Appendix C Project Listing Information

1. Project Name
2. Offset Project Operator or Authorized Project Designee
3. Technical Consultants
4. Other parties with a material interest
5. Date of form completion
6. Form completed by (name, organization)
7. Project Description: 1-2 paragraphs
8. List all points of origin by US state for ODS sourced for this project
9. All ODS sources that will be destroyed under this project:
   Refrigerant Destruction: CFC-11, CFC-12, CFC-113, CFC-114, or CFC-115
   Destruction of ODS Blowing agent in intact building foam: CFC-11, CFC-12, HCFC-22, HCFC-141b
   Destruction of concentrated ODS blowing agent in appliance foam: CFC-11, CFC-12, HCFC-22, HCFC-141b
10. Name of destruction facility
11. Address of destruction facility
12. Is the destruction facility a RCRA permitted hazardous waste combustor (HWC)?
13. If the destruction facility is not a RCRA-permitted HWC, has it met the TEAP requirements for ODS destruction?
14. Project start date
15. Reporting period
16. Have any reductions associated with the project ever been registered with or claimed by another registry or program, or sold to a third party prior to our listing? If yes, identify the registry or program (Vintage and reporting period)
17. Is this project being implemented and conducted as the result of any law, statute, regulation, court order, or other legally binding mandate? If yes, explain.
18. Has a data report been developed? If not, what date will it be in place?
19. Has the project-specific recovery efficiency been determined (fior appliance foam projects only)? If not, when will this factor be established? If yes, what is the factor?
20. Was, or will, any of the destroyed ODS be sources from the US government? If yes, how much?
21. Was, or will, any of the destroyed ODS be considered hazardous waste under US, state or local law? If yes, how much and explain.

Appendix D Data Report Information

1. Project Name
2. Offset Project Operator or Authorized Project Designee
3. Report Date
4. Contact information for Offset Project Operator or Authorize Project Designee
    a. Address, email, phone number
5. Name of Individual Completing Report
6. Reporting Period
7. Does offset project meet all local, state, or federal regulatory requirements?
8. Date(s) of ODS destruction
9. Destruction Facility Name and Location
10. Type of ODS destroyed
11. Mass and composition of ODS as determined by the process outlined in Section 6.6 of the Protocol.
12. Names of all parties and their contact information included in the chain of custody documentation
13. Is all the information in the project listing still accurate? If not provided updates.
14. Baseline Emissions
15. Project Emissions
16. Total Reductions

California Environmental Protection Agency

Air Resources Board

Proposed Regulation to Implement the California Cap-and-Trade Program

PART IV

STAFF REPORT AND COMPLIANCE OFFSET PROTOCOL

LIVESTOCK MANURE (DIGESTER) PROJECTS

Release Date: October 28, 2010

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State of California

California Environmental Protection Agency
AIR RESOURCES BOARD
Office of Climate Change

STAFF REPORT: INITIAL STATEMENT OF REASONS PROPOSED REGULATION TO IMPLEMENT THE CALIFORNIA CAP-AND-TRADE PROGRAM

PART IV

STAFF REPORT AND COMPLIANCE OFFSET PROTOCOL

LIVESTOCK MANURE (DIGESTER) PROJECTS

Public Hearing to Consider the Proposed Regulation to Implement the California Cap-and-Trade Program

Date of Release: October 28, 2010
Scheduled for Consideration: December 16, 2010

Location:

California Air Resources Board
Byron Sher Auditorium
1001 I Street
Sacramento, California 95814

This report has been reviewed by the staff of the California Air Resources Board and approved for publication. Approval does not signify that the contents necessarily reflect the views and policies of the Air Resources Board, nor does mention of trade names or commercial products constitute endorsement or recommendation for use.

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Compliance Offset Protocol for
Livestock Manure (Digester) Projects
Date: October 13, 2010

Staff Report

I. Introduction and Background on Compliance Offset Protocols

A. Staff Proposal

Staff is recommending the Board adopt four compliance offset protocols to support the proposed Cap-and-Trade program. They include a compliance offset protocol for Livestock Manure (digester) projects, Ozone Depleting Substances destruction projects, Urban Forest projects, and Forest Projects. This part discusses the development of a compliance offset protocol for Livestock Manure (digester) projects.

B. Rationale for Compliance Offset Protocols

The Air Resources Board's (ARB or Board) proposed cap-and-trade program allows the use of offsets, emission reductions from uncapped sectors, to comply with emission reduction obligations. Offset credits are issued from projects developed using ARB-adopted compliance offset protocols. Compliance offset protocols contain the project eligibility criteria to ensure reductions are additional, quantification methodologies and regulatory verification and enforcement requirements, as required by AB32. Therefore, they represent the standard by which offset projects are reviewed and judged. They contain the basic methods and procedures to conduct the offset project and determine the greenhouse gas reduction benefits. AB 32 also requires that offsets be "real, permanent, quantifiable, verifiable, enforceable, and additional."

C. ARB Transition to Compliance Offset Protocol

In order to encourage early actions to reduce greenhouse gas (GHG) emissions, the Board decided to adopt GHG emission reduction project protocols starting in 2007. In October 2007, the Board adopted its first Forest Project Protocol, version 2.1 developed by the Climate Action Reserve (CAR). In September 2008, the Board adopted the Livestock Manure Project Protocol version 2.1 and Urban Forest Protocol version 1.0, also for early action projects. Finally in September 2009, the Board adopted the Forest Project Protocol version 3.0, an update to version 2.1 to enable greater participation in forest projects. The Ozone Depleting Substances Project Protocol version 1.0 was adopted by CAR in early February 2010, and the timing precluded it from being adopted by the Board.

The adoption of the protocols represented the Board's endorsement of technically sound approaches for carbon accounting for early action projects. Each of these protocols were developed by CAR and taken through an ARB public review process before they were adopted by the Board.

At its February 2010 meeting, the Board requested staff to initiate a public process to transition the offset protocols for use as compliance offset protocols for compliance purposes in the proposed cap-and-trade program. The Board rescinded approval of the early action protocols in order to begin the transition to a regulatory compliance offset program. Staff began the process by reviewing updates made to the early action protocols since the Board adopted them. On June 23, 2010, ARB staff held a public workshop to discuss the four protocols that were under consideration for modification to align with criteria in AB 32 and the proposed cap-and-trade rule.

D. Compliance Offset Protocol Structure and Regulatory Requirements

Offset protocols consist of two main structural elements -project requirements and project quantification. Project requirements include items such as eligibility, monitoring and reporting, and verification and enforcement provisions. AB 32 requires ARB to adopt regulatory requirements for verification and enforcement of any offset reductions used for compliance purposes. Project quantification identifies the quantification methodologies and equations used in project accounting such as baseline determination and calculation of emissions and emission reductions.

Compliance offset protocols will be incorporated by reference into the proposed cap-and-trade regulation. This incorporation makes the offset protocol document an enforceable regulation. AB 32 exempts quantification methodologies from the Administrative Procedure Act (APA), however those elements of the offset protocol are still regulatory. The exemption allows future updates to the quantification methodologies to be made through a public review and Board adoption process but without the need for rulemaking documents. Each offset protocol identifies sections that are considered quantification and exempt from APA requirements. Any changes to the non-quantification elements of the offset protocols would be considered a regulatory update subject to the full regulatory development process.

Since the offset protocols will now be used in the context of a compliance program, staff has modified language in the offset protocols to refer to the regulatory requirements in the proposed cap-and-trade regulation where needed rather than splitting the offset protocols into separate documents based on regulatory requirements and quantification methodologies. In sections where there is a regulatory requirement in the cap-and-trade regulation, staff refers readers to the regulation.

In addition, the proposed cap-and-trade rule includes offset program regulatory requirements, including but not limited to, eligibility criteria for start dates, project locations, offset project reporting periods, project document retention, project listing information, project reporting information, verification requirements, permanence mechanisms for sequestration projects, and enforcement provisions. Where there are regulatory requirements in the cap-and-trade rule, staff has modified language in the offset protocol to align with the rule.

E. Environmental Impacts

The California Environmental Quality Act (CEQA) and ARB policy require an analysis to determine any potentially adverse environmental impacts of any potential projects under the compliance offset program. ARB determined that adoption and implementation of the proposed compliance offset protocols constitute "projects" as defined by Public Resources Code §21000 et seq. The CEQA Guidelines, §15378 provides the definition of a project. ARB has included a tiered environmental review of the proposed cap-and-trade regulation, the offset program, and subsequently adopted compliance offset protocols in the cap-and-trade regulation.

II. Compliance Offset Livestock Manure (Digester) Project Protocol

A. Role of Livestock and Manure Digesters in Climate Change Mitigation

California is home to about 1,800 dairies with over 1.7 million dairy cows. The resulting manure is a significant source of methane that can be emitted to the atmosphere or captured and used for heat and/or energy. Manure treated and stored under anaerobic conditions decomposes to produce methane, which, if uncontrolled, is emitted to the atmosphere. This predominantly occurs when livestock operations manage waste with anaerobic liquid-based systems (e.g. in lagoons, ponds, tanks, or pits). Within the livestock sector, the primary drivers of methane generation include the amount of manure produced and the fraction of volatile solids that decompose anaerobically. Temperature and the retention time of manure during treatment and storage also affect methane production.

Manure digesters (also called biogas control systems) can be used to trap and collect methane from waste stored in anaerobic conditions. The trapping process is achieved by enclosing the manure, which often involves covering a manure lagoon with plastic or otherwise isolating the manure from the ambient environment. Methane captured through the installation and use of an anaerobic digester can be used for electric power production, for heat, as an alternative to natural gas (whether for pipeline injection or on-farm use), or as a transportation fuel, among others.

B. Development of the Livestock (Manure Digester) Compliance Offset Protocol

Throughout its history, the Livestock Project Protocol development process has included both CAR and ARB scoping meetings, workshops, working group meetings and numerous document reviews by various stakeholders including industry, government, academia, and the general public.

After the Board adoption of the Livestock Manure Project Protocol version 2.1 for early action projects, CAR made updates to the Protocol and adopted version 2.2. Version 2.2 provided updates for missing data substitution methods, metering calibration requirements, newer biogas collection efficiency default values to align with EPA, as well as general clarifications and guidance. CAR recently released a draft Version 3.0 which more clearly defines the offset project boundaries in terms of project sources, sinks, and reservoirs.

To transition CAR's protocol to a compliance offset protocol for use in the cap-and-trade program, staff reviewed the quantification methodologies contained within Version 2.2 and CAR's proposed changes to Version 3.0. Staff believes the greenhouse gas quantification methodologies are robust as the science behind methane generation is well understood and all relevant sources and sinks are included in the offset project boundary. The most significant variables affecting methane production, such as temperature, are well accounted for in the offset protocol. Above all, the captured methane is closely measured and monitored to conservatively ensure that offset crediting coincides with the amount of methane being destroyed. In the rare situation where less methane is destroyed than was originally calculated in the baseline, the fact that the methane is being measured prevents over-crediting.

Staff presented the Livestock project protocol at a June 23, 2010, workshop to introduce the protocol to stakeholders and address any questions or concerns at that time. Stakeholders were provided an opportunity to provide feedback on the staff's presentation and proposal for moving ahead with the Livestock project protocol.

C. Description of the Compliance Offset Livestock (Manure Digester) Protocol

Overview

ARB's proposed Compliance Offset Livestock Manure (Digester) Project Protocol is based on the Climate Action Reserve's Livestock Project Protocol version 2.2 and includes the project boundary updates proposed in CAR's draft version 3.0. The offset protocol is applicable to projects in the United States and its Territories.

The Offset protocol identifies quantification methodologies to calculate the annual greenhouse gas benefits from capturing and destroying methane from anaerobic manure treatment and/or storage facilities on dairy cattle and swine farms. To fit into a statewide, national, and international GHG accounting framework, livestock manure digester project accounting must meet recognized and robust standards including the requirements of AB 32. This requires that GHG reductions be real, additional, independently verified, not double-counted, and permanent. The offset protocol is designed to meet these standards and requirements and provide accurate and standardized GHG accounting methods for complete, consistent, transparent, accurate, and conservative accounting GHG emissions and emission reductions associated with manure digester projects. The offset protocol also defines eligibility rules, offset project boundaries, provides GHG reduction and emission calculation methodologies, and identifies procedures for project monitoring, reporting parameters, and verification. All projects that pass the eligibility requirements set forth in this offset protocol and the cap-and-trade regulation are eligible to register GHG reductions for the duration of the project-crediting period, which is ten years.

Additionality

Eligible projects under this offset protocol must result in reductions that are additional to what would have occurred in the absence of the project. The offset protocol ensures additionality utilizing a performance standard approach and a regulatory additionality requirement.

The performance standard is an identified standard of performance applicable to all manure management projects. The purpose of a performance standard is to establish a threshold that is significantly better than average, business-as-usual greenhouse gas (GHG) emissions for a specified activity, which, if met or exceeded by a project developer, satisfies the criterion of "additionality." If the project meets the threshold, then it exceeds what would happen under the business-as-usual scenario and generates surplus/additional GHG reductions. This offset protocol uses a technology-specific threshold; sometimes also referred to as a practice-based threshold, where it serves as "best-practice standard" for managing livestock manure. Data shows that California livestock operations (dairy, in particular) manage waste in a manner primarily in liquid-based systems that are very suitable for digesters. Yet even in these favorable conditions digesters are found on less than 1% of the dairies. This indicates that installing a bio-gas control system is above and beyond common practice and therefore instillation of a bio-gas control system meets the performance standard.

In addition to the performance standard, eligible projects must show regulatory additionality, meaning that there are no state or federal regulations or local agency ordinances or rulings or mandates requiring the installation of a biogas control system. In addition, projects must comply with all applicable local, state,

and national regulations, whether for air and water quality, energy regulations, or others.

Permanence

GHG reductions resulting from the instillation of bio-gas control systems are permanent. The offset protocol requires that the biogas control system destroy captured methane gas that would otherwise have been emitted to the atmosphere in the absence of the project. Captured biogas can be destroyed on-site, or transported for off-site use (e.g. through gas distribution or transmission pipeline), or used to power vehicles. Regardless of how project developers take advantage of the captured biogas, the ultimate fate of the methane must be destruction.

Quantification Methodologies

The quantification method in the offset protocol is originally derived from the Kyoto Protocol's Clean Development Mechanism (ACM0010 V.2), the EPA's Climate Leaders Program (Draft Manure Offset Protocol, October 2006), and the RGGI Model Rule (January 5, 2007).

The calculation methodologies in the offset protocol include emissions and emission reductions from manure production, treatment, storage and disposal. The offset protocol covers direct emissions of methane (CH4) and carbon dioxide (CO2) associated with waste production, treatment and storage, and waste disposal including emissions associated with transporting manure. Emission calculations for direct CH4 and CO2 emissions associated with the project include variables such as animal mass, population, and ambient average temperature as well as variables related to the resulting biogas such as collection and destruction efficiencies. Quantifying the GHG impact associated with installing a BCS requires the use of both modeled reductions as well as the utilization of metered data from the BCS to be used as a check on the modeled reductions.

Because of the uncertainty in the calculation methodologies for determining nitrous oxide (N2O) emissions associated with projects, these emissions or emission reductions are not included in the current offset protocol. In addition, the use of biogas for producing power for the electricity grid or electricity for on-site use, thereby displacing fossil-fueled power plant GHG emissions, is considered a complementary and separate GHG project activity and is not included within the offset protocol accounting framework.

Monitoring, Reporting, and Verification

Project developers are responsible for monitoring the performance of the project and operating each component of the biogas collection and destruction system in

a manner consistent with the manufacturer's recommendations. The methane capture and control system must be monitored with continuous measurement equipment that directly meters project bio-gas every 15 minutes.
In addition, the operational activity of the destruction devices must be monitored and documented at least hourly to ensure actual methane destruction.

If for any reason the destruction device or the operational monitoring equipment (for example, the thermal coupler on the flare) is inoperable, then all metered biogas going to the particular device is assumed to be released to atmosphere during the period of inoperability. The offset protocol also includes QA/QC requirements for measurement monitoring equipment including gas-flow meters and continuous methane analyzers.

Project developers must report GHG reductions resulting from project activities and submit verified emission reduction reports annually. For transparency, project information will be made publically available.

III. Specific Changes made to CAR's Livestock Project Protocol

Staff is not proposing any technical or quantification changes from CAR's Protocol version 2.2 and has incorporated CAR's recent proposed protocol updates (version 3.0). Revisions have been made to CAR's protocol to align project requirements with the regulatory requirements for compliance offset protocols.

Broadly, the types of changes made to transition CAR's protocol to an ARB compliance offset protocol included:

- Aligning and clarifying terminology to match ARB regulations, such as project developer versus operator, CRTs versus offset credits, project start date versus project commencement, etc.
- Aligning requirements such as listing and reporting requirements to match Cap and Trade regulations
- Requiring ARB's regulatory verification program for accreditation of verification bodies, verification services, conflict of interest, etc.

The following list provides specific changes made to transition CAR's protocol to an ARB compliance offset protocol:

- Referenced to CAR protocol and removed all other references;
- Removed references specific to CAR and their process, including references to CRT's, CAR attestation forms that ARB does not need to implement the offset protocol, verification requirements, and process for starting a project.
- Some text was removed and replaced with references to the regulatory language. This includes removing the table showing eligibility rule overview,

language on legal requirements and performance standard, and the project documentation section;

- Modified terminology to be consistent with the regulation.
    - Project developers are now offset project operators or authorized project designees;
    - Project start date changed to project commencement;
    - Project Monitoring and Operation changed to Project Documentation;
    - Record Keeping Section and changed to Document Retention;
    - Updated glossary to reflect regulatory definitions.
- Aligned start date eligibility with ARB regulation and changed project commencement information to be in line with ARB's regulatory process;
- Changed the Reporting period and verification cycle to align with regulation;
- Changed 12 month reporting period for a project to a single calendar year;
- Included annual reporting requirements, project data report requirements and record retention requirements;
- Project listing requirements replaced the project submittal form;
- Changed verification to be in line with regulation and removed language on project developer disclosure of non-compliance to verifier;
- Removed text on non-compliance due to "acts of nature"
- Removed text that was unrelated or unnecessary for project quantification, or implementation.

IV. References

CAR (2010) Livestock Project Protocol Version 2.2. November 3, 2009. http://www.climateactionreserve.org/how/protocols/adopted/livestock/current-livestock-project-protocol/
(accessed August 30, 2010)

CAR (2010) Draft Livestock Project protocol Version 3.0. July 27, 2010. http://www.climateactionreserve.org/how/protocols/adopted/livestock/livestock-project-protocol-revision/
(accessed August 30, 2010)

California Environmental Protection Agency

AIR RESOURCES BOARD

Compliance Offset Protocol for Livestock Manure (Digester) Projects

Capturing and Destroying Methane from Manure Management Systems

Adopted: [INSERT Date of Board Adoption]

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Abbreviations and Acronyms

ARB	California Air Resources Board
BCS	Biogas control system
CAR	Climate Action Reserve
CH_4	Methane
CNG	Condensed natural gas
CO_2	Carbon dioxide
EPA	U.S. Environmental Protection Agency
GHG	Greenhouse gas
GWP	Global Warming Potential
IPCC	Intergovernmental Panel on Climate Change
lb	Pound
LNG	Liquefied natural gas
MT	Metric ton or tonne
N_2O	Nitrous oxide
NG	Natural gas
QA/QC	Quality Assurance/Quality Control
Regulation	Regulation, title 17, California Code of Regulations, sections 95800 et seq.
scf	Standard cubic foot
SSR	Source, sink, and reservoirs
t	Metric ton or tonne
TAM	Typical average mass

1 Introduction

The Compliance Offset Protocol for Livestock Manure (Digester) Projects provides methods to quantify and report greenhouse gas (GHG) emission reductions associated with the installation of a biogas control system (BCS) for manure management on dairy cattle and swine farms. The protocol focuses on quantifying the change in methane emissions, but also accounts for effects on carbon dioxide emissions. The protocol is based on the Climate Action Reserve's Livestock Project Protocol Version 2.2[1] and includes some clarifications and updates proposed in the draft Version 3.0[2].

Offset Project Operators or Authorized Project Designees that install manure biogas capture and destruction technologies use the methods contained in this document to quantify and report GHGs. The protocol provides eligibility rules, methods to quantify reductions, project-monitoring instructions, and procedures for reporting offset project data reports. Additionally, all projects must submit to annual, independent verification by ARB-accredited verification bodies. Requirements for verification bodies to verify offset project emissions data reports are provided in the Regulation.

This protocol is designed to ensure the complete, consistent, transparent, accurate, and conservative quantification of GHG emission reductions associated with a livestock digester project. The protocol is comprised of both quantification methodologies and regulatory program requirements to develop a livestock project and generate compliance offset credits.

AB 32 exempts quantification methodologies from the Administrative Procedure Act (APA)[3], however those elements of the protocol are still regulatory. The exemption allows future updates to the quantification methodologies to be made through a public review and Board adoption process but without the need for rulemaking documents. Each protocol identifies sections that are considered quantification and exempt from APA requirements. Any changes to the non-quantification elements of the offset protocols would be considered a regulatory update subject to the full regulatory development process. Those sections that are considered to be a quantification methodology are clearly indicated in the title of the chapter or subchapter if only a portion of that chapter is considered part of the quantification methodology of the protocol.

[1] CAR (2009) Livestock Project Protocol Version 2.2. November 3, 2009. http://www.climateactionreserve.org/wp-content/uploads/2009/03/Livestock-Project-Protocol-Version2.2.pdf (accessed November 3, 2009)

[2] CAR (2010) Draft Livestock Project Protocol Version 3.0. July 27, 2010.] http://www.climateactionreserve.org/wpcontent/uploads/2010/07/DRAFT_Livestock_Project_Protocol_V3_072710.pdf (accessed July 27, 2010)

[3] Health and Safety Code section 38571.

2 The GHG Reduction Project

2.1 Background

Manure treated and stored under anaerobic conditions decomposes to produce methane, which, if uncontrolled, is emitted to the atmosphere. This predominantly occurs when livestock operations manage waste with anaerobic liquid-based systems (e.g. in lagoons, ponds, tanks, or pits). Within the livestock sector, the primary drivers of methane generation include the amount of manure produced and the fraction of volatile solids that decompose anaerobically. Temperature and the retention time of manure during treatment and storage also affect methane production.

2.2 Project Definition – Quantification Methodology

For the purpose of this protocol, the GHG reduction project is defined as the installation of a biogas control system that captures and destroys methane gas from anaerobic manure treatment and/or storage facilities on livestock operations.[4] The biogas control system must destroy methane gas that would otherwise have been emitted to the atmosphere in the absence of the project from uncontrolled anaerobic treatment and/or storage of manure.[5]

Captured biogas can be destroyed on-site, or transported for off-site use (e.g. through gas distribution or transmission pipeline), or used to power vehicles. Regardless of how offset project operators or authorized project designees take advantage of the captured biogas, the ultimate fate of the methane must be destruction.

"Centralized digesters" that integrate waste from more than one livestock operation also meet the definition of an offset project.[6]

2.3 The Offset Project Operator or Authorized Project Designee

The offset project operator or authorized project designee is responsible for project listing, monitoring, reporting and verification. The offset project operator or authorized project designee must submit the information in Appendix C of this protocol to meet the listing requirements in the Regulation. The Offset Project Operator or Authorized Project Designee must have legal authority to implement the offset project.

[4] Biogas control systems are commonly called digesters, which may be designed and operated in a variety of ways, from ambient temperature covered lagoons to heated lagoons to mesophilic plug flow or complete mix concrete tank digesters.

[5] The installation of a BCS at an existing livestock operation where the primary manure management system is aerobic (produces little to no methane) may result in an increase of the amount of methane emitted to the atmosphere. Thus, the BCS must digest manure that would primarily be treated in an anaerobic system in the absence of the project in order for the project to meet the definition of an offset project.

[6] The protocol also does not preclude project operators from co-digesting organic matter in the biogas control system. However, the additional organics could impact the nutrient properties of digester effluent, which project operators should consider when assessing the project's associated water quality impacts.

3 Eligibility Rules

Projects must meet the definition of an offset project and must fully satisfy the eligibility rules in the Regulation in order to receive an offset credit.

3.1 Location

Only projects located in the United States and its territories, or on U.S. tribal lands, are eligible to create compliance offset credits under this protocol.

3.2 Project Commencement

The project commencement is defined as the date at which the project's biogas control system (BCS) becomes operational. For the purposes of this protocol, a BCS is considered *operational* on the date at which the system begins producing and destroying methane gas upon completion of an initial start-up period. Projects with commencement dates prior to December 31, 2006 are not eligible under this protocol. Projects may always be submitted for listing prior to their commencement date.

3.3 Project Crediting Period

Offset project operators or authorized project designees are eligible to create GHG reductions for compliance offsets according to this protocol for a period of ten years following the project's commencement date.

3.4 Anaerobic Baseline - Quantification Methodology

Offset project operators or authorized project designees must demonstrate that the depth of the anaerobic lagoons or ponds prior to the project's implementation were sufficient to prevent algal oxygen production and create an oxygen-free bottom layer; which means at least 1 meter in depth.

Greenfield livestock projects (i.e., projects that are implemented at new livestock facilities that have no prior manure management system) are eligible only if the offset project operator or authorized project designee can demonstrate that uncontrolled anaerobic storage and/or treatment of manure is common practice in the industry and geographic region where the project is located.

3.5 Additionality

The protocol must meet the additionality requirements in the Regulation. In summary, the activity must not be required by or undertaken to comply with any federal, state, local law or ordinance, or other legally binding mandates in the project's jurisdiction.

3.6 Regulatory Compliance

As stated in the Regulation offset project operators or authorized project designees must fulfill all applicable local, regional and national requirements on environment impact assessments that apply based on the offset project location. Projects must also meet any other local, regional, and national requirements that might apply. Projects are not eligible to receive offset credits for GHG reductions that occur as the result of

collection or destruction activities that are not in compliance with regulatory requirements.

4 The GHG Assessment Boundary – Quantification Methodology

The GHG Assessment Boundary delineates the GHG sources, sinks, and reservoirs (SSRs) that shall be assessed by offset project operators or authorized project designees to determine the net change in emissions associated with installing a BCS. This protocol's assessment boundary captures sources from waste production to disposal, including off-site manure disposal. However, the calculation procedure only incorporates methane and carbon dioxide, so while nitrous oxide sources are technically within the boundary they are not assessed in the calculation procedure.

This protocol does not account for carbon dioxide emission reductions associated with displacing grid-delivered electricity or fossil fuel use.

CO_2 emissions associated with the generation and destruction of biogas are considered biogenic emissions[7] (as opposed to anthropogenic) and are not included in the GHG Assessment Boundary.

Figure 4.1 provides a general illustration of the GHG Assessment Boundary, indicating which SSRs are included or excluded from the boundary. All SSRs within the dashed line are accounted for under this protocol.

Table 4.1 provides greater detail on each SSR and information for the SSRs and gases from the GHG Assessment Boundary.

[7] The rationale is that carbon dioxide emitted during combustion represents the carbon dioxide that would have been emitted during natural decomposition of the manure. Emissions from the biogas control system do not yield a net increase in atmospheric carbon dioxide because they are theoretically equivalent to the carbon dioxide absorbed during plant/feed growth.

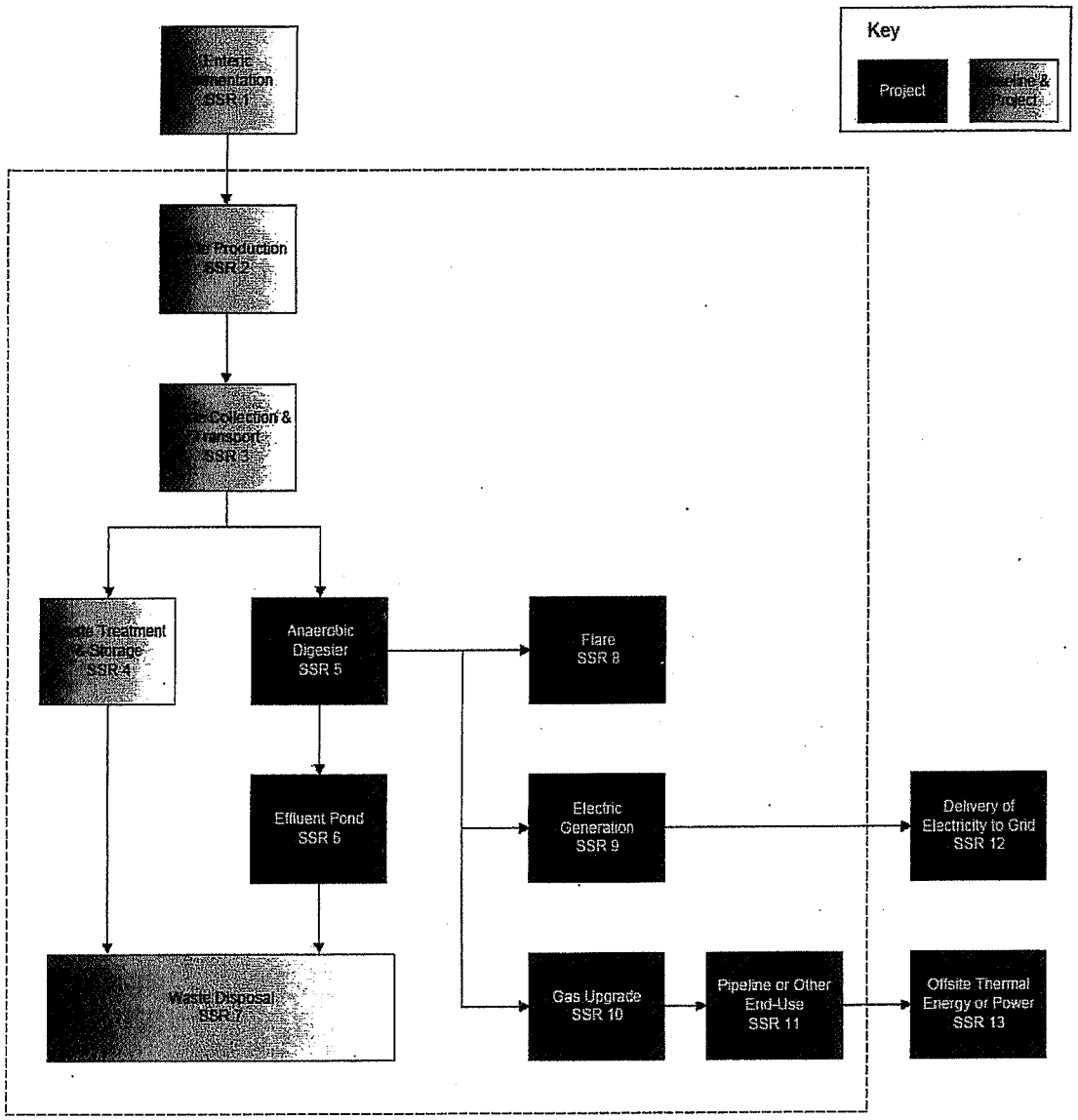


Figure 4.1. General Illustration of the GHG Assessment Boundary

Table 4.1 relates GHG source categories to sources and gases, and indicates inclusion in the calculation methodology. It is intended to be illustrative – GHG sources are indicative for the source category, GHGs in addition to the main GHG are also mentioned, where appropriate.

Table 4.1. Description of all Sources, Sinks, and Reservoirs

SSR	GHG Source	Gas	Relevant to Baseline (B) or Project (P)	Included/ Excluded
1	Emissions from enteric fermentation	CH_4	B, P	*Excluded*
2	Emissions from waste deposits in barn, milking parlor, or pasture/corral	N_2O	B, P	*Excluded*
	Emissions from mobile and stationary support equipment	CO_2	B, P	*Included*
		CH_4		*Excluded*
		N_2O		*Excluded*
3	Emissions from mechanical systems used to collect and transport waste (e.g. engines and pumps for flush systems; vacuums and tractors for scrape systems)	CO_2	B, P	*Included*
		CH_4		*Excluded*
		N_2O		*Excluded*
	Vehicle emissions (e.g. for centralized digesters)	CO_2		*Included*
		CH_4		*Excluded*
		N_2O		*Excluded*
4	Emissions from waste treatment and storage including: anaerobic lagoons, dry lot deposits, compost piles, solid storage piles, manure settling basins, aerobic treatment, storage ponds, etc.	CO_2	B, P	*Excluded*
		CH_4		*Included*
		N_2O		*Excluded*
	Emissions from support equipment	CO_2		*Included*
		CH_4		*Excluded*
		N_2O		*Excluded*
5	Emissions from the anaerobic digester due to biogas collection inefficiencies and venting events	CH_4	P	*Included*
6	Emissions from the effluent pond	CH_4	P	*Included*
		N_2O		*Excluded*
7	Emissions from land application	N_2O	B, P	*Excluded*
	Vehicle emissions for land application and/or	CO_2	B, P	*Included*
		CH_4		*Excluded*

SSR	GHG Source	Gas	Relevant to Baseline (B) or Project (P)	Included/ Excluded
	off-site transport	N_2O		*Excluded*
8	Emissions from combustion during flaring, including emissions from incomplete combustion of biogas	CO_2	P	*Excluded*
		CH_4		*Included*
		N_2O		*Excluded*
9	Emissions from combustion during electric generation, including incomplete combustion of biogas	CO_2	P	*Excluded*
		CH_4		*Included*
		N_2O		*Excluded*
10	Emissions from upgrading biogas for pipeline injection or use as CNG/LNG fuel	CO_2	P	*Included*
		CH_4		*Excluded*
		N_2O		*Excluded*
11	Emissions from combustion of biogas by end user of pipeline or CNG/LNG, including incomplete combustion	CO_2	P	*Excluded*
		CH_4		*Included*
		N_2O		*Excluded*
12	Delivery and use of project electricity to grid	CO_2	P	*Excluded*
		CH_4		
		N_2O		
13	Use of project-generated thermal energy	CO_2	P	*Excluded*
		CH_4		
		N_2O		
	Project construction and decommissioning emissions	CO_2	P	*Excluded*
		CH_4		
		N_2O		

5 Quantifying GHG Emission Reductions – Quantification Methodology[8]

GHG emission reductions from a livestock project are quantified by comparing actual project emissions to baseline emissions at the project site. Baseline emissions are an estimate of the GHG emissions from sources within the GHG Assessment Boundary that would have occurred in the absence of the livestock project. Project emissions are actual GHG emissions that occur at sources within the GHG Assessment Boundary. Project emissions must be subtracted from the baseline emissions to quantify the project's total net GHG emission reductions (Equation 5.1).

Offset project operators and authorized project designees should take note that some equations to calculate baseline and project emissions are run on a month-by-month basis and activity data monitoring takes place at varying levels of frequency. As applicable, monthly emissions data (for baseline and project) are summed together to calculate annual emission reductions.

The current methodology for quantifying the GHG impact associated with installing a BCS requires the use of both modeled reductions (following Equation 5.2 to Equation 5.4 and Equation 5.6 to Equation 5.9) as well as the utilization of ex-post metered data from the BCS to be used as a check on the modeled reductions.

ARB recognizes that there can be material differences between modeled methane emission reductions and the actual metered quantity of methane that is captured and destroyed by the BCS due to digester start-up periods, venting events, and other BCS operational issues. These operational issues have the potential to result in substantially less methane destruction than is modeled, leading to an overestimation of GHG reductions in the modeled case.

To address this issue and maintain consistency with international best practice, ARB requires the modeled methane emission reduction results to be compared to the ex-post metered quantity of methane that is captured and destroyed by the BCS. The lesser of the two values will represent the total methane emission reductions for the reporting period. Equation 5.1 below outlines the quantification methodology for calculating the emission reductions from the installation of a BCS.[9]

Equation 5.1. GHG Reductions from Installing a Biogas Control System

$$\text{Total GHG Reductions} = (\text{Modeled baseline emissions}_{CH4} - \text{Project emissions}_{CH4}) + (\text{Baseline emissions}_{CO2} - \text{Project emissions}_{CO2})$$

The (*Modeled baseline emissions* $_{CH4,}$ – *Project emissions* $_{CH4}$) term shall be calculated according to

[8] The entirety of Section 5 is considered a quantification method.

[9] The calculation procedure only addresses direct emissions sources and does not incorporate changes in electricity consumption, which impacts indirect emissions associated with power plants owned and operated by entities other than the livestock operator.

Equation 5.2 to Equation 5.4 and Equation 5.6 to Equation 5.9. The resulting aggregated quantity of methane reductions must then be compared to the ex-post quantity of methane that is metered and destroyed in the biogas collection system, as expressed in Equation 5.10. In the case that the total ex-post quantity of metered and destroyed methane is less than the modeled methane reductions, the metered quantity of destroyed methane will replace the modeled methane reductions.

Therefore, the above equation then becomes:

Total GHG Reductions = (Total quantity of metered and destroyed methane) + (Baseline emissions $_{CO2}$ – Project emissions $_{CO2}$)

5.1 Quantifying Baseline Methane Emissions

Baseline emissions represent the GHG emissions within the GHG assessment boundary that would have occurred if not for the installation of the BCS. For the purposes of this protocol, offset project operators or authorized project designees calculate their baseline emissions according to the manure management system in place prior to installing the BCS. This is referred to as a "continuation of current practices" baseline scenario. Additionally, offset project operators or authorized project designees calculate baseline emissions each year of the project.[10] The procedure assumes there is no BCS in the baseline system. Regarding new livestock operations that install a BCS, offset project operators or authorized project designees establish a modeled baseline scenario using the prevailing system type in use for the geographic area, animal type, and farm size that corresponds to their operation.

The procedure to determine the modeled baseline methane emissions follows Equation 5.2, which combines Equation 5.3 and Equation 5.4.

Equation 5.3 calculates methane emissions from anaerobic manure storage/treatment systems based on site-specific information on the mass of volatile solids degraded by the anaerobic storage/treatment system and available for methane conversion.[11] It incorporates the effects of temperature through the van't Hoff-Arrhenius '*f*' factor and accounts for the retention of volatile solids through the use of monthly assessments. Equation 5.4 is less intensive and applies to non-anaerobic storage/treatment systems. Both Equation 5.3 and Equation 5.4 reflect basic biological principles of methane production from available volatile solids, determine methane generation for each livestock category, and account for the extent to which the waste management system handles each category's manure.

Equation 5.2. Modeled Baseline Methane Emissions

$$BE_{CH4} = \left(\sum_{S,L} BE_{CH4,AS,L} + BE_{CH4,non-AS,L} \right)$$

Where,

			Units
BE_{CH4}	=	Total annual baseline methane emissions, expressed in carbon	tCO_2e/yr

[10] Conversely, under a "static baseline," a project operator would assess baseline emissions once before project implementation and use that value throughout the project lifetime.

[11] Anaerobic storage/treatment systems generally refer to anaerobic lagoons, or storage ponds, etc.

		dioxide equivalent	
$BE_{CH4,AS,L}$	=	Total annual baseline methane emissions from anaerobic storage/treatment systems by livestock category 'L', expressed in carbon dioxide equivalent	tCO_2e/yr
$BE_{CH4,non-AS,L}$	=	Total annual baseline methane emissions from non-anaerobic storage/treatment systems, expressed in carbon dioxide equivalent	tCO_2e/yr

Equation 5.3. Modeled Baseline Methane Emissions from Anaerobic Storage/Treatment Systems

$$BE_{CH4,AS} = \sum_{L,AS} VS_{deg,AS,L} \times B_{0,L} \times 0.68 \times 0.001 \times 21$$

Where,			Units
$BE_{CH4,AS}$	=	Total annual baseline methane emissions from anaerobic manure storage/treatment systems, expressed in carbon dioxide equivalent	tCO_2e/yr
$VS_{deg,AS,L}$	=	Annual volatile solids degraded in anaerobic manure storage/treatment system 'AS' from livestock category 'L'	kg dry matter
$B_{0,L}$	=	Maximum methane producing capacity of manure for livestock category 'L' – see Appendix A, Table A.3	m^3 CH_4/kg of VS
0.68	=	Density of methane (1 atm, 60°F)	kg/m^3
0.001	=	Conversion factor from kg to metric tons	
21	=	Global Warming Potential factor of methane to carbon dioxide equivalent	

$$VS_{deg,AS,L} = \sum_{AS,L} VS_{avail,AS,L} \times f$$

Where,			Units
$VS_{deg,AS,L}$	=	Annual volatile solids degraded by anaerobic manure storage/ treatment system 'AS' by livestock category 'L'	kg dry matter
$VS_{avail,AS,L}$	=	Monthly volatile solids available for degradation from anaerobic manure storage/treatment system 'AS' by livestock category 'L'()	kg dry matter
f	=	The van't Hoff-Arrhenius factor = "the proportion of volatile solids that are biologically available for conversion to methane based on the monthly temperature of the system"	

$$VS_{avail,AS,L} = \left(VS_L \times P_L \times MS_{AS,L} \times dpm \times 0.8\right) + \left(VS_{avail-1,AS} - VS_{deg-1,AS}\right)$$

Where,			Units
$VS_{avail,AS,L}$	=	Monthly volatile solids available for degradation in anaerobic storage/treatment system 'AS' by livestock category 'L'	kg dry matter
VS_L	=	Volatile solids produced by livestock category 'L' on a dry matter basis. *Important* – refer to Box 5.1 for using appropriate units for VS_L values from Appendix A	kg/ animal/ day
P_L	=	Annual average population of livestock category 'L' (based on monthly population data)	
$MS_{AS,L}$	=	Percent of manure sent to (managed in) anaerobic manure storage/treatment system 'AS' from livestock category 'L' [12]	%
dpm	=	Days per month	days/ month
0.8	=	System calibration factor	
$VS_{avail-1,AS}$	=	Previous month's volatile solids available for degradation in anaerobic system 'AS'	kg
$VS_{deg-1,AS}$	=	Previous month's volatile solids degraded by anaerobic system 'AS'	kg

[12] The MS value represents the percent of manure that would be sent to (managed by) the anaerobic manure storage/treatment systems in the baseline case – as if the biogas control system was never installed.

$$f = \exp\left[\frac{E(T_2 - T_1)}{RT_1T_2}\right]$$

Where,			Units
f	=	The van't Hoff-Arrhenius factor	
E	=	Activation energy constant (15,175)	cal/mol
T_1	=	303.16	Kelvin
T_2	=	Monthly average ambient temperature (K = °C + 273). If T_2 < 5 °C then f = 0.104	Kelvin
R	=	Ideal gas constant (1.987)	cal/Kmol

Equation 5.4. Modeled Baseline Methane for Non-Anaerobic Storage/Treatment Systems

$$BE_{CH4,nAS} = \left(\sum_{L,S} P_L \times MS_{L,nAS} \times VS_L \times 365 \times MCF_{nAS} \times B_{0,L}\right) \times 0.68 \times 0.001 \times 21$$

Where,			Units
$BE_{CH4,nAS}$	=	Total annual baseline methane emissions from non-anaerobic storage/treatment systems, expressed in carbon dioxide equivalent	tCO_2e/yr
P_L	=	Annual average population of livestock category 'L' (based on monthly population data)	
$MS_{L,nAS}$	=	Percent of manure from livestock category 'L' managed in non-anaerobic storage/treatment systems	%
VS_L	=	Volatile solids produced by livestock category 'L' on a dry matter basis. *Important* – refer to Box 5.1 for using appropriate units for VS_L values from Appendix A	kg/ animal/ day
365	=	Days in a year	days/yr
$MCF_{,nAS}$	=	Methane conversion factor for non-anaerobic storage/treatment system 'S' – See Appendix A	%
$B_{0,L}$	=	Maximum methane producing capacity for manure for livestock category 'L' – Appendix A, Table A.3	m^3 CH_4/kg of VS dry matter
0.68	=	Density of methane (1 atm, 60°F)	kg/m^3
0.001	=	Conversion factor from kg to metric tons	
21	=	Global Warming Potential factor of methane to carbon dioxide equivalent	

Box 5.1. Daily Volatile Solids for All Livestock Categories

Consistent with international best-practice, it is recommended that appropriate VS_L values for Dairy livestock categories be obtained from the State-specific lookup tables (Tables B.5.a – B.5.f) provided in Appendix A. When possible, use the year corresponding to the appropriate emission year. If the current year's table is not available, use the most current year.

VS_L values for all other livestock can be found in Appendix A, Table A.3.

Important - Units provided for all VS values in Appendix A are in (kg/day/1000kg), in order to get VS_L in the appropriate units (kg/animal/day), the following equation must be used:

$$VS_L = VS_{table} \times \frac{Mass_L}{1000}$$

Where,			Units
VS_L	=	Volatile solid excretion on a dry matter weight basis	kg/ animal/ day
VS_{Table}	=	Volatile solid excretion from lookup table (Table A.3 and Table A.5a. - A.5.d.)	kg/ day/ 1000kg
$Mass_L$	=	Average live weight for livestock category 'L', if site specific data is unavailable, use values from Appendix A, Table A.2	kg

5.1.1 Variables for Calculating Baseline Methane

The calculation procedure uses a combination of site-specific values and default factors.

Population – PL

The procedure requires offset project operators or authorized project designees to differentiate between livestock categories ('L') – e.g. lactating dairy cows, non-milking dairy cows, heifers, etc. This accounts for differences in methane generation across livestock categories(see Appendix A, Table A.2). The population of each livestock category is monitored on a monthly basis, and for Equation 5.4 averaged for an annual total population.

Volatile solids – VS_L

This value represents the daily organic material in the manure for each livestock category and consists of both biodegradable and non-biodegradable fractions. The VS content of manure is a combination of excreted fecal material (the fraction of a livestock category's diet consumed and not digested) and urinary excretions, expressed in a dry matter weight basis (kg/animal). This protocol requires that the VS value for all livestock categories be determined as outlined in Box 5.1.

$Mass_L$

This value is the annual average live weight of the animals, per livestock category. This data is necessary because default VS values are supplied in units of kg/day/1000kg mass, therefore the average mass of the corresponding livestock category is required in order to convert the units of VS into kg/day/animal. Site specific livestock mass is preferred for all livestock categories. If site specific data is unavailable, Typical Average Mass (TAM) values can be used (Appendix A, Table A.2).

Maximum methane production – $B_{0,L}$

This value represents the maximum methane-producing capacity of the manure, differentiated by livestock category ('L') and diet. Offset project operators or authorized project designees use the default B_0 factors from Appendix A, Table A.3.

MS

The MS value apportions manure from each livestock category to an appropriate manure management system component ('S'). It reflects the reality that waste from the operation's livestock categories are not managed uniformly. The MS value accounts for the operation's multiple types of manure management systems. It is expressed as a percent (%), relative to the total amount of waste produced by the livestock category. As waste production is normalized for each livestock category, the percentage should be calculated as percent of population for each livestock category. For example, a dairy operation might send 85% of its milking cows' waste to an anaerobic lagoon and 15% could be deposited in a corral. In this situation an MS value of 85% would be assigned to Equation 5.3 and 15% to Equation 5.4.

Importantly, the MS value indicates where the waste would be managed in the baseline scenario – i.e. where the manure would end-up if the digester was never installed.

Methane conversion factor – MCF

Each manure management system component has a volatile solids-to-methane conversion efficiency, which represents the degree to which maximum methane production (B_0) is achieved. Methane production is a function of the extent of anaerobic conditions present in the system, the temperature of the system, and the retention time of organic material in the system.

According to this protocol, for anaerobic lagoons, storage ponds, liquid slurry tanks etc., offset project operators or authorized project designees perform a site-specific calculation of the mass of volatile solids degraded by the anaerobic storage/treatment system. This is expressed as "degraded volatile solids" or "VS_{deg}" in Equation 5.3, which equals the system's monthly available volatile solids multiplied by "f," the van't Hoff-Arrhenius factor. The 'f' factor effectively converts total available volatile solids in the anaerobic manure storage/treatment system to methane-convertible volatile solids, based on the monthly temperature of the system.

The multiplication of "VS_{deg}" by "B_0" gives a site-specific quantification of the uncontrolled methane emissions that would have occurred in the absence of a digester – from the anaerobic storage and/or treatment system, taking into account each livestock category's contribution of manure to that system.

This method to calculate methane emissions reflects the site-specific monthly biological performance of the operation's anaerobic manure handling systems that existed pre-project, as predicted by the van't Hoff-Arrhenius equation using farm-level data on temperature, VS loading, and system VS retention time.

Default MCF values for non-anaerobic manure storage/treatment are available in Appendix A, which are used for Equation 5.4.

5.2 Quantifying Project Methane Emissions

Project emissions are actual GHG emissions that occur within the GHG assessment boundary after the installation of the BCS. Project emissions are calculated on an annual, *ex-post* basis. But like baseline emissions, some parameters are monitored on a monthly basis. Methane emissions from manure storage and/or treatment systems other than the digester are modeled much the same as in the baseline scenario.

As shown in Equation 5.5, project methane emissions equal:

- The amount of methane created by the BCS that is not captured and destroyed by the control system, plus
- Methane from the digester effluent storage pond (if necessary), plus
- Methane from sources in the waste treatment and storage category other than the BCS and associated effluent pond. This includes all other manure treatment systems such as compost piles, solids storage, daily spread, etc.

Consistent with ACM0010 and this protocol's baseline methane calculation approach, the formula to account for project methane emissions incorporates all potential sources

within the waste treatment and storage category. Non-BCS-related sources follow the same calculation approach as provided in the baseline methane equations. Several activity data for the variables in Equation 5.9 will be the same as those in Equation 5.2 – Equation 5.4.

Although not common under normal digester operation, it is possible that a venting event may occur due to failure of digester cover materials, the digester vessel, or the gas collection system, or due to a planned maintenance event. In the event that a system failure or planned operation results in the venting of biogas, the quantity of methane released to the atmosphere shall be estimated according to Equation 5.7.

Equation 5.5. Project Methane Emissions

$$PE_{CH4} = [(PE_{CH4,\ BCS} + PE_{CH4,\ EP} + PE_{CH4,\ non\text{-}BCS}) \times 21]$$

Where,			Units
PE_{CH4}	=	Total annual project methane emissions, expressed in carbon dioxide equivalent	tCO_2e/yr
$PE_{CH4,\ BCS}$	=	Annual methane emissions from the BCS – Equation 5.6	tCH_4/yr
$PE_{CH4,\ EP}$	=	Annual methane emissions from the BCS Effluent Pond – Equation 5.8	tCH_4/yr
$PE_{CH4,\ non\text{-}BCS}$	=	Annual methane emissions from sources in the waste treatment and storage category other than the BCS and associated Effluent Pond – Equation 5.9	tCH_4/yr
21	=	Global Warming Potential factor of methane to carbon dioxide equivalent	

Equation 5.6. Project Methane Emissions from the Biogas Control System

$$PE_{CH4,BCS} = \left[\left(CH_{4,meter} \right) \left(\left(\frac{1}{BCE} \right) - BDE_{i,weighted} \right) \right] + CH_{4,vent,i}$$

Where,			Units
$PE_{CH4, BCS}$	=	Monthly methane emissions from the BCS, to be aggregated annually	tCH_4/yr
$CH_{4,meter}$	=	Monthly quantity of methane collected and metered	tCH_4/ month
BCE	=	Monthly methane collection efficiency of the BCS. Offset project operators or authorized project designeesshall use the appropriate default value provided in Table A.4	% (as a decimal)
$BDE_{i,weighted}$	=	Monthly weighted average of all destruction devices used in month i.	% (as a decimal)
$CH_{4,vent,i}$	=	The monthly quantity of methane that is vented to the atmosphere due to BCS venting events, as quantified in Equation 5.7 below.	

$$CH_{4,meter} = F \times (520/T)^{\pi} \times (P/1)^{\pi} \times CH_{4,conc} \times 0.0423 \times 0.000454$$

Where,			Units
$CH_{4,meter}$	=	Monthly quantity of methane collected and metered [13]	tCH_4/ month
F	=	Measured volumetric flow of Biogas per month	scf/month

[13] This value reflects directly measured biogas mass flow and methane concentration in the biogas to the combustion device.

Equation 5.6. Continued

T	=	Temperature of the Biogas flow ($^{o}R = {}^{o}F + 459.67$)	^{o}R (Rankine)
P	=	Pressure of the Biogas flow	atm
$CH_{4,conc}$	=	Measured methane concentration of Biogas from the most recent methane concentration measurement	% (as a decimal)
0.0423	=	Density of methane gas (1atm, 60°F)	$lbsCH_4/scf$
0.000454	=	Conversion factor, lbs to metric tons	

** The terms (520/T) and (P/1) should be omitted if the continuous flow meter internally corrects for temperature and pressure to 60°F and 1atm.*

$$BDE_{i,\,weighted} = \frac{\sum_{DD}\left(BDE_{DD} \times F_{i,DD}\right)}{F_i}$$

Where,			Units
$BDE_{i,weighted}$	=	Monthly weighted average of all destruction devices used in month i	fraction
BDE_{DD}	=	Default methane destruction efficiency of a particular destruction device 'DD'. See Appendix A for default destruction efficiencies by destruction device[14]	fraction
$F_{i,DD}$	=	Monthly flow of biogas to a particular destruction device 'DD'	scf/month
F_i	=	Total monthly measured volumetric flow of biogas to all destruction devices	scf/month

Equation 5.7. Methane Emissions from Venting Events

$$CH_{4,vent,i} = \left(MS_{BCS} + (F_{pw} \times t)\right) \times CH_{4,conc} \times 0.04230 \times 0.000454$$

Where,			Units
MS_{BCS}	=	Maximum biogas storage of the BCS system	SCF
F_{pw}	=	The average total flow of biogas from the digester for the entire week prior to the venting event	SCF/day
t	=	The average total flow of biogas from the digester for the entire week prior to the venting event	days

[14] Project operators have the option to use either the default methane destruction efficiencies provided, or site specific methane destruction efficiencies as provided by an ARB approved source test plan, for each of the combustion devices used in the project.

Equation 5.8. Project Methane Emissions from the BCS Effluent Pond[15]

$$PE_{CH4,EP} = VS_{ep} \times B_{o,ep} \times 365 \times 0.68 \times MCF_{ep} \times 0.001$$

Where,			Units
$PE_{CH4,EP}$	=	Methane emissions from the Effluent Pond	tCH_4/yr
VS_{ep}	=	Volatile solid to effluent pond – 30% of the average daily VS entering the digester	kg/day
$B_{o,ep}$	=	Maximum methane producing capacity (of VS dry matter)[16]	m^3CH_4/kg
365	=	Days in a year	days/yr
0.68	=	Density of methane (1 atm, 60°F)	kg/m^3
MCF_{ep}	=	Methane conversion factor, Appendix A. Offset project operators or authorized project designees shall use the *liquid slurry* MCF value for effluent ponds	Fraction
0.001	=	Conversion factor from kg to metric tons	

$$VS_{ep} = \left(\sum_{L} (VS_L \times P_L \times MS_{L,BCS}) \right) \times 0.3$$

Where,			Units
VS_L	=	Volatile solids produced by livestock category 'L' on a dry matter basis. *Important* – refer to Box 5.1 for using appropriate units for VS_L values from Appendix A	kg/ animal/ day
P_L	=	Annual average population of livestock category 'L' (based on monthly population data	
$MS_{L,BCS}$	=	Fraction of manure from livestock category 'L' that is managed in the BCS	fraction
0.3	=	Default value representing the amount of VS that exits the digester as a percentage of the VS entering the digester	fraction

[15] If no effluent pond exists and project operators send digester effluent (VS) to compost piles or apply directly to land, for example, then the VS for these cases should also be tracked using Equation 5.8.

[16] The B_o value for the project effluent pond is not differentiated by livestock category. Project operators could use the B_o value that corresponds with an average of the operation's livestock categories that contributes manure to the biogas control system. Supporting laboratory data and documentation need to be supplied to the verifier to justify the alternative value.

Equation 5.9. Project Methane Emissions from *Non*-BCS Related Sources[17]

$$PE_{CH4,nBCS} = \left(\sum_{L}(EF_{CH4,L}(nBCSs) \times P_L)\right) \times 0.001$$

Where,

			Units
$PE_{CH4, nBCS}$	=	Methane from sources in the waste treatment and storage category other than the BCS and associated Effluent Pond	tCH_4/yr
$EF_{CH4,L}$	=	Emission factor for the livestock population from non-BCS-related sources (nBCSs, calculated below)	$kgCH_4$/ head/ yr
P_L	=	Population of livestock category 'L'	
0.001	=	Conversion factor from kg to metric tons	

$$EF_{CH4,L}(nBCSs) = (VS_L \times B_{o,L} \times 365 \times 0.68) \times \left(\sum_{S}(MCF_S \times MS_{L,S})\right)$$

Where,

			Units
$EF_{CH4,L}$	=	Methane emission factor for the livestock population from non-biogas control system related sources (nBCSs)	$kgCH_4$/ head/ yr
VS_L	=	Volatile solids produced by livestock category 'L' on a dry matter basis. *Important* – refer to Box 5.1 for using appropriate units for VS_L values from Appendix A	kg/ animal/ day
$B_{o,L}$	=	Maximum methane producing capacity for manure for livestock category 'L' (of VS dry matter), Appendix A, Table A.3	m^3 CH_4/kg
365	=	Days in a year	days/yr
0.68	=	Density of methane (1 atm, 60°F)	kg/m^3
MCF_S	=	Methane conversion factor for system component 'S', Appendix A	fraction
$MS_{L,S}$	=	Percent of manure from livestock category L that is managed in non-BCS system component 'S'	fraction

5.3 Metered Methane Destruction Comparison

As described above, ARB requires all projects to compare the modeled methane emission reductions for the reporting period, as calculated in Equation 5.2 - Equation 5.4 and Equation 5.6 - Equation 5.9 above, with the actual metered amount of methane that is destroyed in the BCS over the same period. The lesser of the two values is to be used as the total methane emission reductions for the reporting period in question.

In order to calculate the metered methane reductions, the monthly quantity of biogas that is metered and destroyed by the BCS must be aggregated over the reporting period. In the event that an offset project operator or authorized project designee is reporting reductions for a period of time that is less than a full year, the total modeled methane emission reductions would be aggregated over this time period and compared with the metered methane that is destroyed in the BCS over the same period of time. For example, if a project is reporting and verifying only 6 months of data, July – December for instance, the modeled emission reductions over this 6 month period would be compared to the total metered biogas destroyed over the same six month

[17] According to this protocol, non-BCS-related sources means manure management system components (system component 'S') other than the biogas control system and the BCS effluent pond (if used).

period, and the lesser of the two values would be used as the total methane emission reduction quantity for this 6 month period.

Equation 5.10 below details the metered methane destruction calculation.

Equation 5.10. Metered Methane Destruction

$$CH_{4,destroyed} = \sum_{months} (CH_{4,meter} \times BDE_{i,weighted}) \times 21$$

Where,

			Units
$CH_{4,destroyed}$	=	Aggregated quantity of methane collected and destroyed during the reporting period	tCO_2e/yr
$CH_{4,meter}$	=	Monthly quantity of methane collected and metered. See Equation 5.6	tCH_4/ month
$BDE_{i,weighted}$	=	Monthly weighted average of all destruction devices used in month i[18] See Equation 5.6	% (as a decimal)
21	=	Global Warming Potential factor of methane to carbon dioxide equivalent	

Determining the methane emission reductions

- If $CH_{4,destroyed}$ is less than ($BE_{CH4} - PE_{CH4}$) as calculated in Equation 5.2 - Equation 5.4 and Equation 5.6 - Equation 5.9 for the reporting period, the methane emission reductions are equal to $CH_{4,destroyed}$
- Otherwise, the methane emission reductions are equal to ($BE_{CH4} - PE_{CH4}$)

5.4 Quantifying Baseline and Project Carbon Dioxide Emissions

Sources of carbon dioxide emissions associated with a project may include electricity use by pumps and equipment, fossil fuel generators used to power pumping systems or milking parlor equipment, tractors that operate in barns or freestalls, on-site manure hauling trucks, or vehicles that transport manure off-site. Changes in carbon dioxide emissions from these sources may be small, but any net increase in emissions shall be accounted for. Offset project operators or authorized project designees may either use Equation 5.11 to calculate the net change in carbon dioxide emissions, or, if they can demonstrate during verification that project carbon dioxide emissions are estimated to be equal to or less than 5% of the total baseline emissions of methane, the offset project operator or authorized project designee may estimate baseline and project carbon dioxide emissions. All estimates or calculations of anthropogenic carbon dioxide emissions within the GHG Assessment Boundary must be verified and included in emission reduction calculations.

If calculations or estimates indicate that the project results in a net decrease in carbon dioxide emissions from grid-delivered electricity, mobile and stationary sources, then for quantification purposes the net change in these emissions must be specified as zero (i.e., $CO_{2,net} = 0$ in Equation 5.11).

[18] Project operators have the option to use either the default methane destruction efficiencies provided, or site specific methane destruction efficiencies as provided by an ARB approved source test plan, for each of the combustion devices used in the project.

Carbon dioxide emissions from the combustion of biogas are considered biogenic emissions and are excluded from the GHG Assessment Boundary.

Equation 5.11 below calculates the net change in anthropogenic carbon dioxide emissions resulting from the project activity.

Equation 5.11. Carbon Dioxide Emission Calculations

$CO_{2,net} = (BE_{CO2MSC} - PE_{CO2MSC})$

Where,			Units
$CO_{2,net}$	=	Net change in anthropogenic carbon dioxide emissions from electricity consumption and mobile and stationary combustion sources resulting from project activity	tCO_2/yr
BE_{CO2MSC}	=	Total annual baseline carbon dioxide emissions from electricity consumption and mobile and stationary combustion sources (see equation below)	tCO_2/yr
PE_{CO2MSC}	=	Total annual project carbon dioxide emissions from electricity consumption and mobile and stationary combustion sources (see equation below)	tCO_2/yr

All electricity consumption and stationary and mobile combustion are calculated using the equation:

$$CO_{2,MSC} = \left(\sum_c QE_c \times EF_{CO2,e}\right) + \left[\left(\sum_c QF_c \times EF_{CO2,f}\right) \times 0.001\right]$$

Where,			Units
$CO_{2,MSC}$	=	Anthropogenic carbon dioxide emissions from electricity consumption and mobile and stationary combustion sources	tCO_2
QE_c*	=	Quantity of electricity consumed for each emissions source 'c'	MWh/yr
$EF_{CO2,e}$	=	CO_2 emission factor *e* for electricity used; see Appendix A for emission factors by eGRID subregion	tCO_2/MWh
$EF_{CO2,f}$	=	Fuel-specific emission factor *f* from Appendix A	kg CO_2/ MMBTU or kg CO_2/ gallon
QF_c	=	Quantity of fuel consumed for each mobile and stationary emission source 'c'	MMBTU/yr or gallon/yr
0.001	=	Conversion factor from kg to metric tons	

* If total electricity being generated by project activities is > the additional electricity consumption, then QE_c shall not be accounted for in the project emissions and shall be omitted from the equation above.

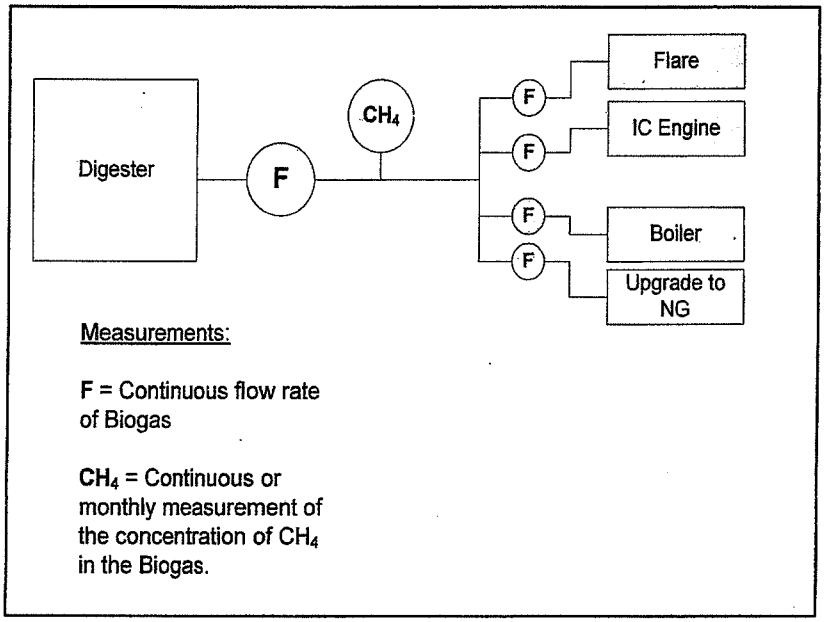
6 Project Documentation and Monitoring Requirements

Offset project operators and authorized project designees are responsible for monitoring the performance of the project and operating each component of the biogas collection and destruction system in a manner consistent with the manufacturer's specifications. The methane capture and control system must be monitored with measurement equipment that directly meters:

1. The total flow of biogas, measured continuously and recorded every 15 minutes or totalized and recorded at least daily, adjusted for temperature and pressure, prior to delivery to the destruction device(s)
2. The flow of biogas delivered to each destruction device[19], measured continuously and recorded every 15 minutes or totalized and recorded at least daily, adjusted for temperature and pressure
3. The fraction of methane in the biogas, measured with a continuous analyzer or, alternatively, with quarterly measurements

Flow data must be corrected for temperature and pressure at 60°F and 1 atm, either internally or by following Equation 5.6.

Figure 6.1 represents the suggested arrangement of the biogas flow meters and methane concentration metering equipment.



Note: The number of flow meters must be sufficient to track the total flow as well as the flow to each combustion device. The above example includes one more flow meter than would be necessary to achieve this objective.

[19] A single meter may be used for multiple, identical destruction devices. In this instance, methane destruction in these units will be eligible only if both units are monitored to be operational.

Operational activity of the destruction devices shall be monitored and documented at least hourly to ensure actual methane destruction. GHG reductions will not be accounted for or credited during periods in which the destruction device is not operational.

If for any reason the destruction device or the operational monitoring equipment (for example, the thermal coupler on the flare) is inoperable, all metered biogas going to the particular device shall be assumed to be released to atmosphere during the period of inoperability. During the period of inoperability, the destruction efficiency of the device must be assumed to be zero. In Equation 5.10, the monthly destruction efficiency (BDE) value shall be adjusted accordingly. See Box 6.1 for an example BDE adjustment.

Box 6.1. Example BDE Adjustment

As an example, consider a situation where the primary destruction device is an open flare with a BDE of 96%, and it is found to be inoperable for a period of 5 days of a 30 day month. Assume that the total flow of biogas to the flare for the month is 3,000,000 scf, and that the total flow recorded for the 5 day period of inoperability is 500,000 SCF. In this case the monthly BDE would be adjusted as follows:

*BDE =[(0.96*2,500,000) +(0.0 * 500,000)] / 3,000,000 = 80%*

6.1.1 Biogas Measurement Instrument QA/QC – Quantification Methodology

All gas flow meters[20] and continuous methane analyzers must be:

- Cleaned and inspected on a quarterly basis, with the activities performed and "as found/as left condition" of the equipment documented
- Field checked by a trained professional for calibration accuracy with the percent drift documented, using either a portable instrument (such as a pitot tube)[21] or manufacturer specifications, at the end of but no more than two months prior to the end date of the reporting period[22]
- Calibrated by the manufacturer or a certified calibration service per manufacturer's specifications or every 5 years, whichever is more frequent

If the field check on a piece of equipment reveals accuracy outside of a +/- 5% threshold, calibration by the manufacturer or a certified service provider is required for that piece of equipment.

For the interval between the last successful field check and any calibration event confirming accuracy below the +/- 5% threshold, all data from that meter or analyzer

[20] Field checks and calibrations of flow meters shall assess the volumetric output of the flow meter.

[21] It is recommended that a professional third party calibration service be hired to perform flow meter field checks if using pitot tubes or other portable instruments, as these types of devices require professional training in order to achieve accurate readings.

[22] Instead of performing field checks, the project operator may instead have equipment calibrated by the manufacturer or a certified calibration service per manufacturer's specifications, at the end of but no more than two months prior to the end date of the reporting period to meet this requirement.

must be scaled according to the following procedure. These adjustments must be made for the entire period from the last successful field check until such time as the meter is properly calibrated.

1. For calibrations that indicate under-reporting (lower flow rates, or lower methane concentration), the metered values must be used without correction.
2. For calibrations that indicate over-reporting (higher flow rates, or higher methane concentration), the metered values must be adjusted based on the greatest calibration drift recorded at the time of calibration.

For example, if a project conducts field checks quarterly during a year-long reporting period, only three months of data will be subject at any one time to the penalties above. However, if the offset project operator or authorized project designee feels confident that the meter does not require field checks or calibration on a greater than annual basis, then failed events will accordingly require the penalty to be applied to the entire year's data. Frequent calibration may minimize the total accrued drift (by zeroing out any error identified), and result in smaller overall deductions.

In order to provide flexibility in verification, data monitored up to two months after a field check may be verified. As such, the end date of the reporting period must be no more than two months after the latest successful field check.

If a portable instrument is used (such as a handheld methane analyzer), the portable instrument shall be calibrated at least annually by the manufacturer or at an ISO 17025 accredited laboratory.

6.1.2 Missing Data – Quantification Methodology

In situations where the flow rate or methane concentration monitoring equipment is missing data, the offset project operator or authorized project designee shall apply the data substitution methodology provided in Appendix B. If for any reason the destruction device monitoring equipment is inoperable (for example, the thermal coupler on the flare), no emission reductions can be credited for the period of inoperability.

6.2 Monitoring Parameters – Quantification Methodology

Provisions for monitoring other variables to calculate baseline and project emissions are provided in Table 6.1. The parameters are organized by general project factors and then by the calculation methods.

Table 6.1. Project Monitoring Parameters

Parameter	Description	Data unit	calculated (c) measured (m) reference(r) operating records (o)	Measurement frequency	Comment
General Project Parameters					
Regulations	Project operator compliance with regulatory requirements relating to the manure digester project	Environmental regulations	n/a	Annually	Information used to: 1) To demonstrate ability to meet the Legal Requirement Test – where regulation would require the installation of a BCS. 2) To demonstrate compliance with associated environmental rules, e.g. criteria pollutant and effluent discharge limits. *Verifier:* Determine regulatory agencies responsible for regulating livestock operation; Review regulations and site permits pertinent to livestock operation
L	Type of livestock categories on the farm	Livestock categories	o	Monthly	Select from list provided in Appendix A, Table A.2. *Verifier:* Review herd management software; Conduct site visit; Interview operator.
MS_L	Fraction of manure from each livestock category managed in the baseline waste handling system 'S'	Percent (%)	o	Annually	Reflects the percent of waste handled by the system components 'S' pre-project. Applicable to the entire operation. Within each livestock category, the sum of MS values (for all treatment/storage systems) equals 100%. Select from list provided in Appendix A, Table A.1. *Verifier:* Conduct site visit; Interview operator; Review baseline scenario documentation.

Parameter	Description	Data unit	calculated (c) measured (m) reference(r) operating records (o)	Measurement frequency	Comment
P_L	Average number of animals for each livestock category	Population (# head)	o	Monthly	*Verifier*: Review herd management software; Review local air and water quality agency reporting submissions, if available (e.g. in CA, dairies with more than 500 cows report farm information to CARB).
$Mass_L$	Average live weight by livestock category	kg	o, r	Monthly	From operating records, or if on-site data is unavailable, from lookup table (Appendix A Table A.2). *Verifier*: Conduct site visit; Interview livestock operator; Review average daily gain records, operating records.
T	Average monthly temperature at location of the operation	°C	m/o	Monthly	Used for van't Hoff Calculation and for choosing appropriate MCF value. *Verifier*: Review temperature records obtained from weather service.
Baseline Methane Calculation Variables					
$B_{0,L}$	Maximum methane producing capacity for manure by livestock category	(m^3 CH_4/kgVS)	r	Annually	From Appendix A, Table A.3. *Verifier*: Verify correct value from table used.
MCF_S	Methane conversion factor for manure management system component 'S'	Percent (%)	r	Annually	From Appendix A. Differentiate by livestock category *Verifier*: Verify correct value from table used.
VS_L	Daily volatile solid production	(kg/animal/day)	r, c	Annually	Appendix A, Table A.3 and Table A.5a-d; see Box 5.1 to convert units from (kg/day/1000kg) to (kg/animal/day). *Verifier*: Ensure appropriate year's table is used; Review data units.

Parameter	Description	Data unit	calculated (c) measured (m) reference(r) operating records (o)	Measurement frequency	Comment
VS_{avail}	Monthly volatile solids available for degradation in each anaerobic storage system, for each livestock category	kg	c, o	Monthly	Calculated value from operating records. *Verifier*: Ensure proper calculations; Review operating records.
VS_{deg}	Monthly volatile solids degraded in each anaerobic storage system, for each livestock category	Kg	c, o	Monthly	Calculated value from operating records. *Verifier*: Ensure proper calculations; Review operating records.
f	van't Hoff-Arrhenius factor	n/a	c	Monthly	The proportion of volatile solids that are biologically available for conversion to methane based on the monthly temperature of the system. *Verifier*: Ensure proper calculations; Review calculation; Review temperature data.
Project Methane Calculation Variables – BCS + Effluent Pond					
$CH_{4,\ destroyed}$	Aggregated amount of methane collected and destroyed in the BCS	Metric tons of CH_4	c, m	Annually	Calculated as the collected methane times the destruction efficiency (see the '$CH_{4,meter}$' and 'BDE' parameters below) *Verifier:* Review meter reading data, confirm proper operation of the destruction device(s); Ensure data is accurately aggregated over the correct amount of time.

Parameter	Description	Data unit	calculated (c) measured (m) reference(r) operating records (o)	Measurement frequency	Comment
$CH_{4,meter}$	Amount of methane collected and metered in BCS	Metric tons of CH_4 (tCH_4)	c, m	Monthly	Calculated from biogas flow and methane fraction meter readings (See 'F' and '$CH_{4,conc}$' parameters below). *Verifier*: Review meter reading data; Confirm proper operation and maintenance in accordance with the manufacturer's specifications; Confirm meter calibration data.
F	Monthly volume of biogas from digester to destruction devices	scf/month	m	Continuously, aggregated monthly	Measured continuously from flow meter and recorded every 15 minutes or totalized and recorded at least once daily. Data to be aggregated monthly. *Verifier*: Review meter reading data; Confirm proper aggregation of data; Confirm proper operation in accordance with the manufacturer's specifications; Confirm meter calibration data.
T	Temperature of the biogas	°R (Rankine)	m	Continuously, averaged monthly	Measured to normalize volume flow of biogas to STP. No separate monitoring of temperature is necessary when using flow meters that automatically measure temperature and pressure, expressing biogas volumes in normalized cubic feet.
P	Pressure of the biogas	atm	m	Continuously, averaged monthly	Measured to normalize volume flow of biogas to STP. No separate monitoring of pressure is necessary when using flow meters that automatically measure temperature and pressure, expressing biogas volumes in normalized cubic feet.

Parameter	Description	Data unit	calculated (c) measured (m) reference(r) operating records (o)	Measurement frequency	Comment
$CH_{4,conc}$	Methane concentration of biogas	Percent (%)	m	Quarterly	Use a direct sampling approach that yields a value with at least 95% confidence. Samples to be taken at least quarterly. Calibrate monitoring instrument in accordance with the manufacturer's specifications. *Verifier*: Review meter reading data; Confirm proper operation in accordance with the manufacturer's specifications.
BDE	Methane destruction efficiency of destruction device(s)	Percent (%)	r, c	Monthly	Reflects the actual efficiency of the system to destroy captured methane gas – accounts for different destruction devices. See Equation 5.6. *Verifier*: Confirm evidence of proper and continuous operation in accordance with the manufacturer's specifications.
BCE	Biogas capture efficiency of the anaerobic digester, accounts for gas leaks.	Percent (%)	r	Annually	Use default value from Table A.4 *Verifier:* Review operation and maintenance records to ensure proper functionality of BCS.
VS_{ep}	Average daily volatile solid of digester effluent to effluent pond	kg/day	c	Annually	If project uses effluent pond, equals 30% of the average daily VS entering the digester (From ACM0010 -V2 Annex I). *Verifier*: Review VS_{ep} calculations.
$MS_{L,BCS}$	Fraction of manure from each livestock category managed in the BCS	Percent (%)	o	Annually	Used to determine the total VS entering the digester. The percentage should be tracked in operational records. *Verifier*: Check operational records and conduct site visit.

Parameter	Description	Data unit	calculated (c) measured (m) reference(r) operating records (o)	Measurement frequency	Comment
Bo_{ep}	Maximum methane producing capacity for manure to effluent pond	(m^3 CH_4/kgVS)	c	Annually	An average of the Bo_{ep} value of the operation's livestock categories that contributes manure to the BCS. *Verifier:* Check calculation.
MCF_{ep}	Methane conversion factor for BCS effluent pond	Percent (%)	r	Annually	Referenced from Appendix A. Offset project operators or authorized project designees should use the *liquid slurry* MCF value. *Verifier:* Verify value from table.
MS_{BCS}	The maximum biogas storage of the BCS system	scf	r	Annually	Obtained from digester system design plans. Necessary to quantify the release of methane to the atmosphere due to an uncontrolled venting event.
F_{pw}	The average flow of biogas from the digester for the entire week prior to the uncontrolled venting event	scf/day	m	Weekly	The average flow of biogas can be determined from the daily records from the previous week.
t	The number of days of the month that biogas is venting uncontrolled from the project's BCS.	Days	m, o	Monthly	The number of days of the month that biogas is venting uncontrolled from the project's BCS.

Parameter	Description	Data unit	calculated (c) measured (m) reference(r) operating records (o)	Measurement frequency	Comment
Project Methane Calculation Variables – Non-BCS Related Sources					
$MS_{L,S}$	Fraction of manure from each livestock category managed in non-anaerobic manure management system component 'S'	Percent (%)	o	Monthly	Based on configuration of manure management system, differentiated by livestock category. *Verifier*: Conduct site visit; Interview operator.
$EF_{CH4,L}$ *(nBCSs)*	Methane emission factor for the livestock population from non-BCS-related sources	($kgCH_4$/head/year)	c	Annually	Emission factor for all non-BCS storage systems, differentiated by livestock category. See Equation 5.9. *Verifiers*: Review calculation, operation records.
Baseline and Project CO_2 Calculation Variables					
$EF_{CO2,f}$	Fuel-specific emission factor for mobile and stationary combustion sources	kg CO_2/MMBTU or kg CO_2/gallon	r	Annually	Refer to Appendix A for emission factors. If biogas produced from digester is used as an energy source, the EF is zero. *Verifier*: Review emission factors.
QF_c	Quantity of fuel used for mobile/stationary combustion sources	MMBTU/year or gallon/year	o, c	Annually	Fuel used by project for manure collection, transport, treatment/storage, and disposal, and stationary combustion sources including supplemental fossil fuels used in combustion device. *Verifier:* Review operating records and quantity calculation.
$EF_{CO2,e}$	Emission factor for electricity used by project	tCO2/MWh	r	Annually	Refer to Appendix A for emission factors. If biogas produced from digester is used to generate electricity consumed the EF is zero. *Verifier*: Review emission factors.
QE_c	Quantity of electricity consumed	MWh/year	o, c	Annually	Electricity used by project for manure collection, transport, treatment/storage, and disposal. *Verifier:* Review operating records and quantity calculation.

7 Reporting Parameters

This section provides requirements on reporting and procedures. It is a priority to facilitate consistent and transparent information disclosure among project operators.

7.1 Annual Reporting Requirements

Offset project operators or authorized project designees must report information contained in Appendix D.

7.2 Document Retention

Offset project operators or authorized project designees are required to keep all information outlined in this protocol as required in the Regulation. Records must be retained for a period of 5 years after the end of the crediting period.

System Information that should be retained by the project operator or authorized project designee should include, but is not limited to:

- All data inputs for the calculation of the baseline emissions and project emission reductions
- CO_2e annual tonnage calculations
- Relevant sections of the BCS operating permits
- BCS information (installation dates, equipment list, etc.)
- Biogas flow meter information (model number, serial number, manufacturer's calibration procedures)
- Cleaning and inspection records for all biogas meters
- Field check results for all biogas meters
- Calibration results for all biogas meters
- Methane monitor information (model number, serial number, calibration procedures)
- Biogas flow data (for each flow meter)
- Biogas temperature and pressure readings (only if flow meter does not correct for temperature and pressure automatically)
- Methane concentration monitoring data
- Destruction device monitoring data (for each destruction device)
- Destruction device, methane monitor and biogas flow monitor information (model numbers, serial numbers, calibration procedures)
- All maintenance records relevant to the BCS, monitoring equipment, and destruction devices

If using a calibrated portable gas analyzer for CH_4 content measurement:

- Date, time, and location of methane measurement
- Methane content of biogas (% by volume) for each measurement
- Methane measurement instrument type and serial number
- Date, time, and results of instrument calibration
- Corrective measures taken if instrument does not meet performance specifications

See the Regulation for record-keeping requirements.

7.3 Reporting Period & Verification Cycle

Offset project operators or authorized project designees must submit an Offset Project Data Report to ARB or an Offset Project Registry annually and be based on a single calendar year.

Verification must be performed annually and be based on a calendar year. A verification statement must be received by ARB by October 1 of the next calendar year for which the statement is verifying destruction.

8 Glossary of Terms

Accredited verifier	A verification firm approved by ARB to provide verification services for offset project operators or authorized project designees.
Additionality	Manure management practices that are above and beyond business-as-usual operation, exceed the baseline characterization, and are not mandated by regulation.
Anaerobic	Pertaining to or caused by the absence of oxygen.
Anthropogenic emissions	GHG emissions resultant from human activity that are considered to be an unnatural component of the Carbon Cycle (i.e. fossil fuel combustion, de-forestation etc.).
Biogas	The mixture of gas (largely methane) produced as a result of the anaerobic decomposition of livestock manure.
Biogas control system (BCS)	A system designed to capture and destroy the biogas that is produced by the anaerobic treatment and/or storage of livestock manure and/or other organic material. Commonly referred to as a "digester."
Biogenic CO_2 emissions	CO_2 emissions resulting from the combustion and/or aerobic decomposition of organic matter. Biogenic emissions are considered to be a natural part of the carbon cycle, as opposed to anthropogenic emissions.
Carbon dioxide (CO_2)	The most common of the six primary greenhouse gases, consisting of a single carbon atom and two oxygen atoms.
CO_2 equivalent (CO_2e)	The quantity of a given GHG multiplied by its total global warming potential. This is the standard unit for comparing the degree of warming which can be caused by different GHGs.
Direct emissions	Greenhouse gas emissions from sources that are owned or controlled by the reporting entity.

Emission factor	A unique value for determining an amount of a greenhouse gas emitted for a given quantity of activity data (e.g. metric tons of carbon dioxide emitted per barrel of fossil fuel burned).
Flare	A destruction device that uses an open flame to burn combustible gases with combustion air provided by uncontrolled ambient air around the flame.
Fossil fuel	A fuel, such as coal, oil, and natural gas, produced by the decomposition of ancient (fossilized) plants and animals.
Greenhouse gas (GHG)	Carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), sulfur hexafluoride (SF_6), hydrofluorocarbons (HFCs), or perfluorocarbons (PFCs).
Global Warming Potential (GWP)	The ratio of radiative forcing (degree of warming to the atmosphere) that would result from the emission of one unit of a given GHG compared to one unit of CO_2.
Indirect emissions	Emissions that are a consequence of the actions of a reporting entity, but are produced by sources owned or controlled by another entity.
Livestock project	Installation of a biogas control system that, in operation, causes a decrease in GHG emissions from the baseline scenario through destruction of the methane component of biogas.
Metric ton (MT) or "tonne"	A common international measurement for the quantity of GHG emissions, equivalent to about 2204.6 pounds or 1.1 short tons.
Methane (CH_4)	A potent GHG with a GWP of 21, consisting of a single carbon atom and four hydrogen atoms.
MMBtu	One million British thermal units.
Mobile combustion	Emissions from the transportation of materials, products, waste, and employees resulting from the combustion of fuels in company owned or controlled mobile combustion sources (e.g. cars, trucks, tractors, dozers, etc.).
Nitrous oxide (N_2O)	A GHG consisting of two nitrogen atoms and a single oxygen atom.
Project baseline	A business-as-usual GHG emission assessment against which GHG emission reductions from a specific GHG reduction activity are measured.

Project operator	An entity that undertakes a project activity, as identified in the Livestock Project Protocol. A project operator may be an independent third party or the dairy/swine operating entity.
Stationary combustion source	A stationary source of emissions from the production of electricity, heat, or steam, resulting from combustion of fuels in boilers, furnaces, turbines, kilns, and other facility equipment.
van't Hoff-Arrhenius factor	The proportion of volatile solids that are biologically available for conversion to methane based on the monthly temperature of the system.
Verification	The process used to ensure that a given participant's greenhouse gas emissions or emission reductions have met the minimum quality standard and complied with ARB's procedures and protocols for calculating and reporting GHG emissions and emission reductions.
Verification body	An accredited firm that is able to render a verification opinion and provide verification services for operators subject to reporting under this protocol.

9 References

ARB exclusively used the CAR Livestock Project Protocol Versions 2.2 and 3.0 as the sole references for this document, and as such, all sources can be found in the CAR documents.

CAR (2009) Livestock Project Protocol Version 2.2.
http://www.climateactionreserve.org/wp-content/uploads/2009/03/Livestock-Project-Protocol-Version2.2.pdf

CAR (2010) Draft Livestock Project Protocol Version 3.0.
http://www.climateactionreserve.org/wpcontent/uploads/2010/07/DRAFT_Livestock_Project_Protocol_V3_072710.pdf

EPA Climate Leaders, Stationary Combustion Guidance (2008).
http://www.epa.gov/climateleaders/documents/resources/stationarycombustionguidance.pdf

EPA eGRID2007, Version 1.1 Year 2005 GHG Annual Output Emission Rates (2008).
http://www.epa.gov/cleanenergy/documents/egridzips/eGRID2007V1_1_year05_GHGOutputRates.pdf

Appendix A Emission Factor Tables – Quantification Methodology

Table A.1. Manure Management System Components

System	Definition
Pasture/Range/ Paddock	The manure from pasture and range grazing animals is allowed to lie as deposited, and is not managed.
Daily spread	Manure is routinely removed from a confinement facility and is applied to cropland or pasture within 24 hours of excretion.
Solid storage	The storage of manure, typically for a period of several months, in unconfined piles or stacks. Manure is able to be stacked due to the presence of a sufficient amount of bedding material or loss of moisture by evaporation.
Dry lot	A paved or unpaved open confinement area without any significant vegetative cover where accumulating manure may be removed periodically.
Liquid/Slurry	Manure is stored as excreted or with some minimal addition of water in either tanks or earthen ponds outside the animal housing, usually for periods less than one year.
Uncovered anaerobic lagoon	A type of liquid storage system designed and operated to combine waste stabilization and storage. Lagoon supernatant is usually used to remove manure from the associated confinement facilities to the lagoon. Anaerobic lagoons are designed with varying lengths of storage (up to a year or greater), depending on the climate region, the volatile solids loading rate, and other operational factors. The water from the lagoon may be recycled as flush water or used to irrigate and fertilize fields.
Pit storage below animal confinements	Collection and storage of manure usually with little or no added water typically below a slatted floor in an enclosed animal confinement facility, usually for periods less than one year.
Anaerobic digester	Animal excreta with or without straw are collected and anaerobically digested in a large containment vessel or covered lagoon. Digesters are designed and operated for waste stabilization by the microbial reduction of complex organic compounds to CO2 and CH4, which is captured and flared or used as a fuel.
Burned for fuel	The dung and urine are excreted on fields. The sun dried dung cakes are burned for fuel.
Cattle and Swine deep bedding	As manure accumulates, bedding is continually added to absorb moisture over a production cycle and possibly for as long as 6 to 12 months. This manure management system also is known as a bedded pack manure management system and may be combined with a dry lot or pasture.
Composting – In-vessel*	Composting, typically in an enclosed channel, with forced aeration and continuous mixing.
Composting – Static pile*	Composting in piles with forced aeration but no mixing.
Composting – Intensive windrow*	Composting in windrows with regular (at least daily) turning for mixing and aeration.
Composting – Passive windrow*	Composting in windrows with infrequent turning for mixing and aeration.
Aerobic treatment	The biological oxidation of manure collected as a liquid with either forced or natural aeration. Natural aeration is limited to aerobic and facultative ponds and wetland systems and is due primarily to photosynthesis. Hence, these systems typically become anoxic during periods without sunlight.

*Composting is the biological oxidation of a solid waste including manure usually with bedding or another organic carbon source typically at thermophilic temperatures produced by microbial heat production.

Table A.2. Livestock Categories and Typical Average Mass (TAM)

Livestock Category (L)	Livestock Typical Average Mass (TAM) in kg
Dairy cows (on feed)	604[b]
Non-milking dairy cows (on feed)	684[a]
Heifers (on feed)	476[b]
Bulls (grazing)	750[b]
Calves (grazing)	118[b]
Heifers (grazing)	420[b]
Cows (grazing)	533[b]
Nursery swine	12.5[a]
Grow/finish swine	70[a]
Breeding swine	198[b]

Table A.3. Volatile Solids and Maximum Methane Potential by Livestock Category

Livestock category (L)	VS_L (kg/day/1,000 kg mass)	$B_{o,L}$[b] ($m^3 CH_4$/kg VS added)
Dairy cows	See Appendix A, Tables 5a-e	0.24
Non-milking dairy cows	5.56	0.24
Heifers	See Appendix A, Tables 5a-e	0.17
Bulls (grazing)	6.04[b]	0.17
Calves (grazing)	6.41[b]	0.17
Heifers (grazing)	See Appendix A, Tables 5a-e	0.17
Cows (grazing)	See Appendix A, Tables 5a-e	0.17
Nursery swine	8.89[b]	0.48
Grow/finish swine	5.36[b]	0.48
Breeding swine	2.71[b]	0.35

Table A.4. Biogas Collection Efficiency (BCE) by Digester Type

Digester Type	Cover Type	Biogas Collection Efficiency (BCE) as a decimal
Covered Anaerobic Lagoon	Bank-to-Bank, impermeable	0.95 (95%)
Complete mix, plug flow, or fixed film digester	Enclosed vessel	0.98 (98%)

Table A.5. 2007 Volatile Solid Default Values for Dairy Cows, Heifers, Heifers-Grazing and Cows-Grazing by State (kg/day/1000 kg mass)

State	VS Dairy Cow	VS Heifer	VS Heifer - Grazing	VS Cows-Grazing
Alabama	8.02	7.42	7.82	7.02
Alaska	8.18	7.42	10.08	9.02
Arizona	10.55	7.42	10.41	9.02
Arkansas	7.11	8.22	7.87	7.00
California	8.98	7.42	7.92	6.85
Colorado	9.11	7.42	7.65	6.46
Connecticut	8.22	6.70	7.66	6.90
Delaware	7.60	6.70	7.89	6.90
Florida	8.40	7.42	7.77	7.02
Georgia	8.80	7.42	7.89	7.02
Hawaii	7.52	7.42	10.30	9.02
Idaho	10.34	7.42	10.80	9.02
Illinois	8.08	7.42	8.11	6.91
Indiana	8.49	7.42	8.01	6.91
Iowa	8.43	7.42	8.20	6.91
Kansas	8.35	7.42	7.68	6.46
Kentucky	7.70	7.42	7.97	7.02
Louisiana	6.88	8.22	7.75	7.00
Maine	7.88	6.70	7.66	6.90
Maryland	7.94	6.70	7.85	6.90
Massachusetts	7.69	6.70	7.78	6.90
Michigan	9.05	7.42	7.95	6.91
Minnesota	8.13	7.42	8.05	6.91
Mississippi	8.09	7.42	7.85	7.02
Missouri	7.21	7.42	7.88	6.91
Montana	8.05	7.42	7.21	6.46
Nebraska	7.98	7.42	7.64	6.46
Nevada	9.75	7.42	10.5	9.02
New Hampshire	8.58	6.70	7.78	6.90
New Jersey	7.64	6.70	7.92	6.90
New Mexico	10.03	7.42	10.64	9.02
New York	8.24	6.70	7.99	6.90
North Carolina	9.07	7.42	7.85	7.02
North Dakota	7.29	7.42	7.40	6.46
Ohio	7.94	7.42	7.94	6.91
Oklahoma	8.04	8.22	8.09	7.00
Oregon	9.49	7.42	10.61	9.02
Pennsylvania	8.27	6.70	8.03	6.90
Rhode Island	7.56	6.70	7.66	6.90
South Carolina	8.73	7.42	7.85	7.02
South Dakota	8.24	7.42	7.50	6.46
Tennessee	8.21	7.42	7.92	7.02
Texas	9.19	8.22	8.20	7.00
Utah	9.75	7.42	10.58	9.02
Vermont	7.95	6.70	7.92	6.90
Virginia	8.64	7.42	7.95	7.02
Washington	10.54	7.42	10.87	9.02
West Virginia	7.29	6.70	7.82	6.90
Wisconsin	8.25	7.42	7.88	6.91
Wyoming	8.13	7.42	7.34	6.46

Table A.6.a IPCC 2006 Methane Conversion Factors by Manure Management System Component/Methane Source 'S'

MCF VALUES BY TEMPERATURE FOR MANURE MANAGEMENT SYSTEMS																			
System[a]		MCFs by average annual temperature (°C)																	
		Cool					Temperate											Warm	
		≤ 10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27
Pasture/Range/Paddock		1.0%					1.5%											2.0%	
Daily spread		0.1%					0.5%											1.0%	
Solid storage		2.0%					4.0%											5.0%	
Dry lot		1.0%					1.5%											2.0%	
Liquid / Slurry	With natural crust cover	10%	11%	13%	14%	15%	17%	18%	20%	22%	24%	26%	29%	31%	34%	37%	41%	44%	48%
	W/out natural crust cover	17%	19%	20%	22%	25%	27%	29%	32%	35%	39%	42%	46%	50%	55%	60%	65%	71%	78%

Table A.6.a Continued

MCF VALUES BY TEMPERATURE FOR MANURE MANAGEMENT SYSTEMS																			
System[a]		MCFs by average annual temperature (°C)																	
		Cool					Temperate											Warm	
		≤ 10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27
Uncovered anaerobic lagoon		66%	68%	70%	71%	73%	74%	75%	76%	77%	77%	78%	78%	78%	79%	79%	79%	79%	80%
Pit storage below animal confinements	< 1 month	3%					3%											3%	
	> 1 month	17%	19%	20%	22%	25%	27%	29%	32%	35%	39%	42%	46%	50%	55%	60%	65%	71%	78%

Table A.6.a Continued

MCF VALUES BY TEMPERATURE FOR MANURE MANAGEMENT SYSTEMS																					
System[a]		MCFs by average annual temperature (°C)																			
		Cool					Temperate											Warm			
		≤ 10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	≥ 2
Anaerobic digester		0-100%					0-100%											0-100%			
Burned for fuel		10%					10%											10%			
Cattle and Swine deep bedding	< 1 month	3%					3%											30%			
Cattle and Swine deep bedding (cont.)	> 1 month	17%	19%	20%	22%	25%	27%	29%	32%	35%	39%	42%	46%	50%	55%	60%	65%	71%	78%	90%	
Composting - In-vessel[b]		0.5%					0.5%											0.5%			
Composting - Static pile[b]		0.5%					0.5%											0.5%			

Table A.6.a Continued

Composting - Intensive windrow[b]	0.5%	1.0%	1.5%
Composting – Passive windrow[b]	0.5%	1.0%	1.5%
Aerobic treatment	0%	0%	0%

a Definitions for manure management systems are provided in Table A.1.
b Composting is the biological oxidation of a solid waste including manure usually with bedding or another organic carbon source typically at thermophilic temperatures produc

Table A.6.b. Biogas Destruction Efficiency Default Values by Destruction Device

If available, the actual source test results for the measured methane destruction efficiency shall be used in place of the default methane destruction efficiency. Otherwise, offset project operators or authorized project designees have the option to use either the default methane destruction efficiencies provided, or the site specific methane destruction efficiencies as provided by a state or local agency accredited source test service provider, for each of the combustion devices used in the project case performed on an annual basis.

Biogas Destruction Device	Biogas Destruction Efficiency (BDE)*
Open Flare	0.96[1]
Enclosed Flare	0.995[1,3]
Lean-burn Internal Combustion Engine	0.936[1,2]
Rich-burn Internal Combustion Engine	0.995[1,2]
Boiler	0.98[1]
Microturbine or large gas turbine	0.995[1]
Upgrade and use of gas as CNG/LNG fuel	0.95
Upgrade and injection into natural gas pipeline	0.98[4]

Table A.7. CO_2 Emission Factors for Fossil Fuel Use

Fuel Type	Heat Content	Carbon Content (Per Unit Energy)	Fraction Oxidized	CO_2 Emission Factor (Per Unit Energy)	CO_2 Emission Factor (Per Unit Mass or Volume)
Coal and Coke	MMBtu / Short ton	kg C / MMBtu		kg CO_2 / MMBtu	kg CO_2 / Short ton
Anthracite Coal	25.09	28.26	1.00	103.62	2,599.83
Bituminous Coal	24.93	25.49	1.00	93.46	2,330.04
Sub-bituminous Coal	17.25	26.48	1.00	97.09	1,674.86
Lignite	14.21	26.30	1.00	96.43	1,370.32
Unspecified (Residential/ Commercial)	22.05	26.00	1.00	95.33	2,102.29
Unspecified (Industrial Coking)	26.27	25.56	1.00	93.72	2,462.12
Unspecified (Other Industrial)	22.05	25.63	1.00	93.98	2,072.19
Unspecified (Electric Utility)	19.95	25.76	1.00	94.45	1,884.53
Coke	24.80	31.00	1.00	113.67	2,818.93
Natural Gas (By Heat Content)	Btu / Standard cubic foot	kg C / MMBtu		kg CO_2 / MMBtu	kg CO_2 / Standard cub. ft.
975 to 1,000 Btu / Std cubic foot	975 – 1,000	14.73	1.00	54.01	Varies
1,000 to 1,025 Btu / Std cubic foot	1,000 – 1,025	14.43	1.00	52.91	Varies
1,025 to 1,050 Btu / Std cubic foot	1,025 – 1,050	14.47	1.00	53.06	Varies
1,050 to 1,075 Btu / Std cubic foot	1,050 – 1,075	14.58	1.00	53.46	Varies
1,075 to 1,100 Btu / Std cubic foot	1,075 – 1,100	14.65	1.00	53.72	Varies
Greater than 1,100 Btu / Std cubic foot	> 1,100	14.92	1.00	54.71	Varies
Weighted U.S. Average	1,029	14.47	1.00	53.06	0.0546
Petroleum Products	MMBtu / Barrel	kg C / MMBtu		kg CO_2 / MMBtu	kg CO_2 / gallon
Asphalt & Road Oil	6.636	20.62	1.00	75.61	11.95
Aviation Gasoline	5.048	18.87	1.00	69.19	8.32
Distillate Fuel Oil (#1, 2 & 4)	5.825	19.95	1.00	73.15	10.15
Jet Fuel	5.670	19.33	1.00	70.88	9.57
Kerosene	5.670	19.72	1.00	72.31	9.76
LPG (average for fuel use)	3.849	17.23	1.00	63.16	5.79
Propane	3.824	17.20	1.00	63.07	5.74
Ethane	2.916	16.25	1.00	59.58	4.14
Isobutene	4.162	17.75	1.00	65.08	6.45
n-Butane	4.328	17.72	1.00	64.97	6.70
Lubricants	6.065	20.24	1.00	74.21	10.72
Motor Gasoline	5.218	19.33	1.00	70.88	8.81
Residual Fuel Oil (#5 & 6)	6.287	21.49	1.00	78.80	11.80
Crude Oil	5.800	20.33	1.00	74.54	10.29
Naphtha (<401 deg. F)	5.248	18.14	1.00	66.51	8.31
Natural Gasoline	4.620	18.24	1.00	66.88	7.36
Other Oil (>401 deg. F)	5.825	19.95	1.00	73.15	10.15
Pentanes Plus	4.620	18.24	1.00	66.88	7.36
Petrochemical Feedstocks	5.428	19.37	1.00	71.02	9.18
Petroleum Coke	6.024	27.85	1.00	102.12	14.65
Still Gas	6.000	17.51	1.00	64.20	9.17
Special Naphtha	5.248	19.86	1.00	72.82	9.10
Unfinished Oils	5.825	20.33	1.00	74.54	10.34
Waxes	5.537	19.81	1.00	72.64	9.58

Source: EPA Climate Leaders, Stationary Combustion Guidance (2008), Table B-2 except:
Default CO_2 emission factors (per unit energy) are calculated as: Carbon Content × Fraction Oxidized × 44/12.
Default CO_2 emission factors (per unit mass or volume) are calculated as: Heat Content x Carbon Content × Fraction Oxidized × 44/12× Conversion Factor (if applicable). Heat content factors are based on higher heating values (HHV).

Table A.8. CO_2 Electricity Emission Factors

eGRID subregion acronym	eGRID subregion name	Annual output emission rates	
		(lb CO_2/MWh)	(metric ton CO_2/MWh)*
AKGD	ASCC Alaska Grid	1,232.36	0.559
AKMS	ASCC Miscellaneous	498.86	0.226
AZNM	WECC Southwest	1,311.05	0.595
CAMX	WECC California	724.12	0.328
ERCT	ERCOT All	1,324.35	0.601
FRCC	FRCC All	1,318.57	0.598
HIMS	HICC Miscellaneous	1,514.92	0.687
HIOA	HICC Oahu	1,811.98	0.822
MROE	MRO East	1,834.72	0.832
MROW	MRO West	1,821.84	0.826
NEWE	NPCC New England	927.68	0.421
NWPP	WECC Northwest	902.24	0.409
NYCW	NPCC NYC/Westchester	815.45	0.370
NYLI	NPCC Long Island	1,536.80	0.697
NYUP	NPCC Upstate NY	720.80	0.327
RFCE	RFC East	1,139.07	0.517
RFCM	RFC Michigan	1,563.28	0.709
RFCW	RFC West	1,537.82	0.698
RMPA	WECC Rockies	1,883.08	0.854
SPNO	SPP North	1,960.94	0.889
SPSO	SPP South	1,658.14	0.752
SRMV	SERC Mississippi Valley	1,019.74	0.463
SRMW	SERC Midwest	1,830.51	0.830
SRSO	SERC South	1,489.54	0.676
SRTV	SERC Tennessee Valley	1,510.44	0.685
SRVC	SERC Virginia/Carolina	1,134.88	0.515

Source: U.S. EPA eGRID2007, Version 1.1 Year 2005 GHG Annual Output Emission Rates (December 2008).
* Converted from lbs CO_2/MWh to metric tons CO_2/MWH using conversion factor 1 metric ton = 2,204.62 lbs.

Appendix B Data Substitution – Quantification Methodology

This appendix shows how to calculate emission reductions when data integrity has been compromised either due to missing data points or a failed calibration. No data substitution is permissible for equipment such as thermocouples which monitor the proper functioning of destruction devices. Rather, the methodologies presented below are to be used only for the methane concentration and flow metering parameters.

B.1 Missing Data

ARB expects that projects will have continuous, uninterrupted data for the entire verification period. However, ARB recognizes that unexpected events or occurrences may result in brief data gaps.

The following data substitution methodology may be used only for flow and methane concentration data gaps that are discrete, limited, non-chronic, and due to unforeseen circumstances. Data substitution can only be applied to methane concentration *or* flow readings, but not both simultaneously. If data is missing for both parameters, no reductions can be credited.

Further, substitution may only occur when two other monitored parameters corroborate proper functioning of the destruction device and system operation within normal ranges. These two parameters must be demonstrated as follows:

1. Proper functioning can be evidenced by thermocouple readings for flares, energy output for engines, etc.
2. For methane concentration substitution, flow rates during the data gap must be consistent with normal operation.
3. For flow substitution, methane concentration rates during the data gap must be consistent with normal operations.

If corroborating parameters fail to demonstrate any of these requirements, no substitution may be employed. If the requirements above can be met, the following substitution methodology may be applied:

Duration of Missing Data	Substitution Methodology
Less than six hours	Use the average of the four hours immediately before and following the outage
Six to 24 hours	Use the 90% lower or upper confidence limit of the 24 hours prior to and after the outage, whichever results in greater conservativeness
One to seven days	Use the 95% lower or upper confidence limit of the 72 hours prior to and after the outage, whichever results in greater conservativeness
Greater than one week	No data may be substituted and no credits may be generated

Note: It is conservative to use the upper confidence limit when calculating emissions from the BCS (Equation 5.6); however it is conservative to use the lower confidence limit when calculating the total amount of methane that is destroyed in the BCS Equation 5.10.

Appendix C Project Listing Information

All information, if applicable, must be completed, even if the answer is also provided elsewhere;

1. Project Name
2. Offset Project Operator or Authorized Project Designee
3. Facility Owner
4. Technical Consultants
5. Other parties with a material interest
6. Date of form completion
7. Form completed by (name, organization)
8. Project Description: 1-2 paragraphs (including type of digester & method of destruction)
9. Project Site Address (including all governing jurisdictions & lat/lon)
10. Name & address of animal facility (if different from project site)
11. Description of type of facility (e.g. dairy, swine, etc.)
12. Project commencement date
13. Reporting period
14. Have any reductions associated with the project ever been registered with or claimed by another registry or program, or sold to a third party prior to our listing? If yes, identify the registry or program (Vintage and reporting period)
15. Is this project being implemented and conducted as the result of any law, statute, regulation, court order, or other legally binding mandate? If yes, explain.

Appendix D Data Report Information

1. Project Name
2. Offset Project Operator or Authorized Project Designee
3. Report Date
4. Contact information for Offset Project Operator or Authorize Project Designee
    a. Address, email, phone number
5. Name of Individual Completing Report
6. Reporting Period
7. Does offset project meet all local, state, or federal regulatory requirements
8. Project Commencement Date
9. Facility Name and Location
10. Is all the information in the project listing still accurate? If not provided updates.
11. Baseline Emissions
12. Project Emissions
13. Total Reductions

California Environmental Protection Agency

Air Resources Board

Proposed Regulation to Implement the California Cap-and-Trade Program

PART V

STAFF REPORT AND COMPLIANCE OFFSET PROTOCOL

U.S. FOREST PROJECTS

Release Date: October 28, 2010

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State of California

California Environmental Protection Agency
AIR RESOURCES BOARD
Office of Climate Change

STAFF REPORT: INITIAL STATEMENT OF REASONS, PROPOSED REGULATION TO IMPLEMENT THE CALIFORNIA CAP-AND-TRADE PROGRAM

PART V

STAFF REPORT AND COMPLIANCE OFFSET PROTOCOL

U.S. FOREST PROJECTS

Public Hearing to Consider the Proposed Regulation to Implement the California Cap-and-Trade Program

Date of Release: October 28, 2010
Scheduled for Consideration: December 16, 2010

Location:

California Air Resources Board
Byron Sher Auditorium
1001 I Street
Sacramento, California 95814

This report has been reviewed by the staff of the California Air Resources Board and approved for publication. Approval does not signify that the contents necessarily reflect the views and policies of the Air Resources Board, nor does mention of trade names or commercial products constitute endorsement or recommendation for use.

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Compliance Offset Protocol for Forest Projects
Date: October 1, 2010

Staff Report

I. Introduction and Background on Compliance Offset Protocols

A. Staff Proposal

Staff is recommending the Board adopt four compliance offset protocols to support the proposed Cap-and-Trade program. They include a compliance offset protocol for Livestock Manure (digester) projects, Ozone Depleting Substances destruction projects, Urban Forest projects, and Forest projects. This part discusses the development of a Compliance Offset Protocol for Forest Projects (Forest Offset Protocol).

B. Rationale for Compliance Offset Protocols

The Air Resources Board's (ARB or Board) proposed cap-and-trade program allows the use of offsets, emission reductions from uncapped sectors, to comply with emission reduction obligations. Offset credits are issued from projects developed using ARB-adopted compliance offset protocols. Compliance offset protocols contain the project eligibility criteria to ensure reductions are additional, quantification methodologies and regulatory verification and enforcement requirements, as required by AB32. Therefore, they represent the standard by which offset projects are reviewed and judged. They contain the basic methods and procedures to conduct the offset project and determine the greenhouse gas reduction benefits. AB 32 also requires that offsets be "real, permanent, quantifiable, verifiable, enforceable, and additional."

C. ARB Transition to Compliance Offset Protocols

In order to encourage early actions to reduce greenhouse gas (GHG) emissions, the Board decided to adopt GHG emission reduction project protocols starting in 2007. In October 2007, the Board adopted its first Forest Project Protocol, Version 2.1 developed by the Climate Action Reserve (CAR). In September 2008, the Board adopted the Livestock Manure Project Protocol Version 2.1 and Urban Forest Protocol Version 1.0, also for early action projects. Finally in September 2009, the Board adopted the Forest Project Protocol Version 3.0, an update to Version 2.1 to enable greater participation in forest projects. The Ozone Depleting Substances Project Protocol Version 1.0 was adopted by CAR in early February 2010, and the timing precluded it from being adopted by the Board.

The adoption of the protocols represented the Board's endorsement of technically sound approaches for carbon accounting for early action projects. Each of these protocols were developed by CAR and taken through an ARB public review process before they were adopted by the Board.

At its February 2010 meeting, the Board requested staff to initiate a public process to transition the protocols for use as compliance offset protocols for compliance purposes in the proposed cap-and-trade program. The Board rescinded approval of the early action protocols in order to begin the transition to a regulatory compliance offset program. Staff began the process by reviewing updates made to the early action protocols since the Board adopted them. On June 23, 2010, ARB staff held a public workshop to discuss the four protocols that were under consideration for modification to align with criteria in AB 32 and the proposed cap-and-trade rule.

D. Compliance Offset Protocol Structure and Regulatory Requirements

Offset protocols consist of two main structural elements, project requirements and project quantification. Project requirements include items such as eligibility, monitoring and reporting, and verification and enforcement provisions. AB 32 requires ARB to adopt regulatory requirements for verification and enforcement of any offset reductions used for compliance purposes. Project quantification identifies the quantification methodologies and equations used in project accounting such as baseline determination and calculation of emissions and emission reductions.

Compliance offset protocols will be incorporated by reference into the proposed cap-and-trade regulation. This incorporation makes the offset protocol document an enforceable regulation. AB 32 exempts quantification methodologies from the Administrative Procedure Act (APA), however those elements of the protocol are still regulatory. The exemption allows future updates to the quantification methodologies to be made through a public review and Board adoption process but without the need for rulemaking documents. Each protocol identifies sections that are considered quantification and exempt from APA requirements. Any changes to the non-quantification elements of the offset protocols would be considered a regulatory update subject to the full regulatory development process.

Since the protocols will now be used in the context of a compliance program, staff has modified language in the protocols to refer to the regulatory requirements in the proposed cap-and-trade regulation where needed rather than splitting the protocols into separate documents based on regulatory requirements and quantification methodologies. In sections where there is a regulatory

requirement in the cap-and-trade regulation, staff refers readers to the appropriate section in the rule.

In addition, the proposed cap-and-trade rule includes offset program regulatory requirements, including but not limited to, eligibility criteria for start dates, project locations, offset project reporting periods, project document retention, project listing information, project reporting information, verification requirements, permanence mechanisms for sequestration projects, and enforcement provisions. Where there are regulatory requirements in the cap-and-trade rule, staff has modified language in the protocol to align with the rule.

E. Environmental Impacts

The California Environmental Quality Act (CEQA) and ARB policy require an analysis to determine any potentially adverse environmental impacts of any potential projects under the compliance offset program. ARB determined that adoption and implementation of the proposed compliance offset protocols constitute "projects" as defined by Public Resources Code §21000 et seq. The CEQA Guidelines, §15378 provides the definition of a project. ARB has included a tiered environmental review of the proposed cap-and-trade regulation, the offset program, and subsequently adopted compliance offset protocols in the cap-and-trade regulation at section 95973.

II. Compliance Offset Protocol for Forest Projects

A. Role of Forests in Climate Change Mitigation

Forests play an essential role in climate change mitigation through their capacity to remove carbon dioxide from the atmosphere through photosynthsis, and sequester carbon for long periods of time in various biomass carbon pools. Trees, through the process of photosynthesis, naturally absorb CO_2 from the atmosphere and store the gas as carbon in their biomass, i.e. trunk (bole), leaves, branches, and roots. Carbon is also stored in the soils that support the forest, as well as the understory plants and litter on the forest floor. Wood products that are harvested from forests can also provide long term storage of carbon. Through sustainable management and protection, forests can help address global climate change. The Forest Offset Protocol is designed to address the forest sector's unique capacity to sequester, store, and emit CO_2. Specifically, there is a significant climate change mitigation opportunity for forests through the reforestation of non-forest or previously deforested lands, forest management activities to increase carbon stocks, and the avoided conversion of at-risk forest lands.

B. Development of the Protocol

CAR began work on the Forest Protocol in April 2003 in response to a mandate set out in California Senate Bill 812. The bill required the establishment of protocols to encourage carbon sink activities by creating an incentive for forest landowners to undertake forest conservation, conservation-based management, and reforestation projects. In October 2007, the Air Resources Board adopted Version 2.1 of the Forest Protocol as a rigorous GHG accounting framework for voluntary purposes. The Board also recognized the need to develop additional methods to encourage greater participation in forest projects, and directed ARB staff to initiate a process to update the Forest Protocol to reduce barriers to participation, while maintaining sound accounting principles.

ARB staff contracted with CAR to lead the update process. A Forest Project Protocol Workgroup was formed to identify and work through major issues to update the protocol. The Workgroup consisted of stakeholders representing forest industry, public lands, non-governmental organizations, government agencies, and academia. CAR and ARB held several joint public workshops over the course of the protocol update process and gathered stakeholder input. The update process was completed in September 2009, and Version 3.0 was adopted by both CAR and ARB. After the Board's approval of Version 3.0, CAR approved a Version 3.1, which clarified language on silvicultural practices and requirements for balancing age and habitat classes.

Following the adoption of Version 3.1 by CAR's Board, there emerged a need to clarify what constitutes a legal constraint when modeling a project's baseline. CAR initially released draft guidance in February 2010 on the question of whether certain California forest management planning documents should be considered legal constraints when determining a project baseline. CAR held a public workshop on the issue in March 2010, before releasing a final staff baseline proposal on June 24, 2010 that included some revisions to the baseline methodology in Version 3.1. In examining the issue of how to account for documents related to California Forest Practice Rules requirements regarding Maximum Sustained Production of High Quality Wood Products, CAR also received comment on the potential for Forest Owners to employ a selection bias in defining a project area, and on Habitat Conservation Plans and Safe Harbor Agreements. CAR incorporated changes into Version 3.2 which requires that Habitat Conservation Plans, Safe Harbor Agreements, and active Timber Harvest Plans be included in the baseline modeling as regulatory constraints, but other long-term planning documents ('Option A' or 'Sustained Yield Plans') do not. It also includes a revised baseline approach to prevent selection bias in defining a project area that takes into consideration the existing carbon stocks on all of a

forest entity's holdings within a logical management unit and new guidance for aggregating forest projects. Version 3.2 was adopted by CAR's Board In August of 2010.

In February 2010, the ARB Board withdrew its previous adoption of voluntary protocols and directed ARB staff to focus efforts on transitioning the voluntary protocols to a form that could function within the state's regulatory cap-and-trade program. ARB used CAR's Forest Project Protocol Version 3.2 as the basis for transitioning to a compliance protocol.

C. Description of the Protocol

Overview

ARB's Compliance Offset Protocol for Forest Projects (Forest Offset Protocol) allows offset project developers in the United States to quantify greenhouse gas emission reductions and removal enhancements associated with forest management activities. A Forest project is a planned set of activities designed to increase removals of CO_2 from the atmosphere, or reduce or prevent emissions of CO_2 to the atmosphere, through increasing and/or conserving forest carbon stocks.

ARB's Forest Offset Protocol is based on Version v3.2 of CAR's voluntary Forest Project Protocol (CAR Protocol). ARB Staff has conducted a detailed review of the quantification methodologies contained in CAR's protocol and believes Version 3.2 represents a detailed and rigorous accounting methodology to quantify GHG emission reductions or removal enhancements from forest projects. The CAR Protocol has greatly benefited from nearly seven years of revisions and use in voluntary forest projects. As the CAR Protocol was developed and updated through the dedicated effort of stakeholder working groups, it has evolved to incorporate the technical and practical input of a wide range of experts. The CAR Protocol quantification methodologies take a conservative approach where uncertainty exists and are structured to ensure that quantified reductions or removals are real, additional to regulatory obligations, maintained for a long period of time, and quantifiable. In addition, the CAR Protocol addresses defining project boundaries, assessing additionality and modeling crediting baselines, quantifying relevant carbon pools, and accounting for the risks of reversals and emissions leakage.

ARB's Forest Offset Protocol covers three types of forest projects:

- *Reforestation Projects*, which involve planting trees on land that has been out of forest cover for at least 10 years or has been subject to a recent significant disturbance.

- *Improved Forest Management Projects*, which involve undertaking management activities to maintain and increase carbon stocks on forested lands.
- *Avoided Conversion Projects*, which involve preventing the conversion of high-risk forestland to a non-forest land use by dedicating the land to continuous forest cover through a conservation easement or transfer to public ownership.

Projects on both private and public lands are eligible.

For purposes of ARB's Forest Offset Protocol, a Forest Owner is defined as the owner of any interest in the property involved in a Forest Project. Generally, a Forest Owner is the legal land owner (owner in fee) of the property involved in a Forest Project. In some cases, one entity may own the land while another entity may have an interest in the trees or the timber on the property, in which case all entities or individuals with interest in the property are collectively considered the Forest Owners, however, a single Offset Project Operator must be identified.

The Offset Project Operator is responsible for undertaking a forest project and ensuring the requirements of the protocol are adhered to, and that all local, regional, and federal requirements are met, however, all Forest Owner(s) are ultimately responsible for all forest project commitments. The Offset Project Operator is responsible for project listing, monitoring, reporting, record retention, and verification activities. Projects are not eligible to receive offset credits for GHG reductions that occur as the result of forest management activities that are not in compliance with all regulatory requirements.

ARB's Forest Offset Protocol also requires forest projects to employ natural forest management, demonstrate sustainable harvesting practices, and maintain or increase live tree biomass over the life of the project. The Forest Offset Protocol also includes provisions that require the use of native species, and prohibit broadcast fertilization. Implementing a forest project does not prevent Forest Owners from managing their lands for timber resources, but rather allows Forest Owners to receive credit for actions taken to maintain and increase carbon sequestration and avoid emissions on their lands.

Additionality

ARB's Forest Offset Protocol requires that any credited reductions be in addition any GHG reductions or removals that would occur through law or regulation, and in addition to what would otherwise occur under a business as usual scenario. Projects must satisfy both a Legal Requirement Test and a Performance Test for additionality, and the protocol contains specific guidance on setting a baseline to ensure only additional reductions are credited. For example, all modeled project baselines must incorporate all legal constraints. Reforestation Projects must demonstrate that the land has been out of forest cover for 10 years, or where a

recent significant disturbance has occurred, demonstrate that reforestation would not be expected to be financially viable without the project or occurs in an area not historically subject to tree harvesting. Improved Forest Management Projects must take various factors into consideration when setting the project baseline, such as carbon stocking levels relative to comparable lands (common practice), historic management practices (high stocking reference), management of other entity forest lands within a logical management unit, financial feasibility of the baseline model, as well as the current stocking levels and legal constraints on the management of project lands. Avoided Conversion Projects must demonstrate both that the conversion of project lands is legally permissible, and through a real estate appraisal, that the project area is suitable to conversion to an identified alternative use, and that the alternative use has a significantly higher market value than maintaining the area as forest land.

Permanence

To ensure permanence, all forest projects commit to maintain all credited emission reductions or removal enhancements for 100 years following the issuance of any offset credit for GHG reductions or removals achieved by the project. For example, if offset credits are issued to a forest project in year 24 following its start date, monitoring and verification activities must be maintained until year 124.

Because GHG reductions and removals from forest projects can be "reversed" if the stored carbon associated with them is released (back) to the atmosphere, mechanisms to ensure permanence are included in the protocol. Many biological and non-biological agents, both natural and human-induced, can cause reversals. Some of these agents cannot completely be controlled and may therefore result in an unintentional reversal, such as natural agents like fire, insects, and wind. Other agents can be controlled, such as the human activities like land conversion and over-harvesting. Under this offset protocol, reversals due to controllable agents are considered intentional. If the quantified GHG reductions and removals in a given year are negative, and offset credits were issued to the forest project in any previous year, it is considered a reversal, regardless of the cause of the decrease.

Permanence of forest project GHG reductions and removals is addressed through three mechanisms:

1. The requirement for all projects to monitor onsite carbon stocks, submit annual offset project data reports, and undergo third-party verification of those reports with site visits at least every six years for the duration of the project life (which is 100 years from the date of the last offset credit issuance).

2. The regulatory obligation for all intentional reversals of GHG reductions and removals be compensated for through retirement of other Compliance Instruments.
3. The maintenance of a Forest Buffer Account by ARB to provide insurance against reversals of GHG reductions and removals due to unintentional causes (including natural disturbances such a fires, pest infestations, or disease outbreaks).

Unintentional reversals are insured against by contributing a percentage of ARB issued Offset Credits to the Forest Buffer Account. All forest projects must contribute a percentage of issued offset credits to the Forest Buffer Account any time compliance credits are issued by ARB. The amount of the contribution is based on a project-specific risk evaluation. If a forest project experiences an unintentional reversal, offset credits from the Forest Buffer Account will be retired in an amount equal to the total amount of carbon that was reversed.

If a reversal is found to be intentional, then the Offset Project Operator or Authorized Project Designee must compensate for the reversal by surrendering compliance instruments from its account equal to the size of the reversal in CO_2-equivalent metric tons.

A forest project will be automatically terminated if a significant disturbance occurs leading to an unintentional reversal that reduces the project's standing live tree carbon stocks below the project's baseline standing live tree carbon stocks. Once a forest project terminates in this manner, the Forest Buffer Account covers the unintentional reversal and the project has no further obligations to under this offset protocol.

A forest project is automatically terminated if project lands are sold to an entity that does not elect to take over project responsibilities and commitments. Such a termination will require a sufficient quantity of compliance instruments to be retired equal to the amount of offset credits issued to the project over the previous 100 years (or the life of the project if less than 100 years) multiplied by the appropriate compensation rate as set forth in the protocol.

A forest project may be voluntarily terminated prior to the end of its crediting period if the required quantities of compliance instruments are retired. For a Reforestation or Avoided Conversion Project, a quantity of compliance instruments equal to the total number of offset credits issued to the project over the preceding 100 years must be retired. For an Improved Forest Management Project, a quantity of compliance instruments equal to the amount of offset credits issued to the project over the previous 100 years (or the life of the project if less than 100 years) multiplied by the appropriate compensation rate as set forth in the protocol must be retired.

Quantification Methodology

Quantification in the Forest Offset Protocol is based on the accounting of carbon stored or emitted from various carbon pools included in the project boundary (in CO_2-equivalent units). All forest projects must account for carbon in standing live tree biomass (above and below ground), standing dead wood, and harvested wood products. In addition, Reforestation Projects must account for carbon in shrubs and herbaceous understory. Projects that involve intensive site preparation activities where soil disturbance exceed more than 25% of project area lands must account for soil carbon. Each project must develop and maintain a forest carbon inventory program. Forest carbon stocks for required carbon pools are quantified primarily through field inventories. Based on the sampling error of the inventory, a statistical confidence deduction may be applied to the carbon stocks to address measurement uncertainty. Sample plots used to develop or update the inventory must never be older than 12 years, and projects are allowed to update their forest carbon inventories using approved models. These models allow projects to account for harvesting and growth and in years when sample plots are not directly measured. Modeled plot data would need to be modified if contradicted by a verification site-visit or future plot measurements.

The Forest Offset Protocol also includes standard approaches and factors for accounting for potential for some increases in GHG emissions outside of the project boundary as a result of the project activity. This is known as emissions leakage. For example, to account for the potential of other forests lands to increase harvesting as a result of reduced harvesting on project lands, the protocol applies a standard factor to annual harvest figures. There are also methods for quantifying the emissions risk of displacing other land uses in reforestation and avoided conversion projects.

Annual project greenhouse gas emission or removals are compared to the project baseline to determine the net emission reductions or removal enhancements eligible for offset crediting.

Monitoring, Reporting, and Verification

Annual project data, including annual GHG reductions or removal enhancements (or reversals), is submitted to ARB for each calendar year in the Offset Project Data Report. Offset project data reports must be verified by an accredited third-party verification body at least once every six years, and all verifications must include a site visit. Each verification will evaluate the emission reductions, removal enhancements or reversals for each calendar year over the period since the last verification was conducted. While verification may take place less often than annually, each calendar year of reported data since the last verification must be verified in years that it occurs. ARB only issues offset credits for verified emission reductions or removal enhancements. For example, a project that has six years of data verified at one time would only be issued offset credits for those years following successful verification of the data.

Project monitoring procedures must be documented in the forest carbon inventory program. The inventory data must be updated each year to account for growth, harvest, and any disturbances or reversals if applicable. Updating the inventory may include incorporating new plot data, modeling, harvest data, or a combination of these.

III. Specific Changes from the Voluntary Protocol

A. Specific Changes from the Voluntary Protocol

The proposed Compliance Offset Protocol for Forest Projects is based on CAR's version 3.2, which includes clarifications and amendments to version 3.1. ARB recognizes the tremendous amount of time and energy that went into drafting each version of the Forest Protocol, and the broad consensus it has achieved on many contentious technical and policy issues. After receiving public comment on the protocol following the June 23rd workshop, ARB staff is not proposing significant modifications to the protocol. The majority of changes were made to align the protocol with the cap-and-trade program. The most significant modifications relate to the enforcement of projects through regulation rather than through legal contracts, and modification of the project crediting period to align with the cap-and-trade regulation. Verification provisions were also revised, to align with ARB's regulatory verification requirements. The following details specific changes made to transition the voluntary forest protocol to an ARB compliance offset protocol. These and other minor modifications are detailed below.

Programmatic changes to align with cap-and-trade program requirements:
A number of programmatic changes were necessary to align the protocol text with the processes and requirements in the cap-and-trade regulation. These relate both to the transition from a voluntary to a regulatory program generally, and specifically the transition from a program administered by CAR to one administered by ARB. These modifications included modifying references to ARB's program and regulatory text, eliminating some forms not required by ARB, and aligning start date eligibility and project commencement requirements with the regulation. Sections containing quantification methodologies were clearly identified, as these are exempt from the APA process. References to CAR's website were changed to reference ARB's website where protocol related documents will be housed. A requirement was also added that projects must fulfill all applicable local, regional, and national requirements on environmental impact assessments to be eligible.

Some areas where the protocol may have been unclear or less standardized were modified to be consistent with a regulatory program. For example, where

'variances' were allowed, they was replaced with requirements for submitting written documentation. Words such as 'guidance' were changed to 'requirements' or 'methods' as appropriate, and words such as 'should' to 'must' to improve clarity and consistency. 'Recommended' methodologies were replaced with language that specifies the methodology as appropriate.

Language was also added to delineate some specific requirements for Qualified Conservation Easements. Most notably, a Qualified Conservation Easement must expressly acknowledge that ARB is a third party beneficiary of the conservation easement with the right to enforce all obligations under the easement and all other rights and remedies conveyed to the holder of the easement. These rights must include standing as an interested party in any proceeding affecting the easement.

Definition and terminology changes to align with cap-and-trade program:
A number of modifications were made to the protocol to align glossary definitions and terminology used in the protocol with the cap-and-trade regulation. It is important to maintain consistency in the use of terms, and that definitions in the protocol not conflict with ARB program requirements. For example, the definition of 'Forest Owner' was modified to align with liability requirement in cap-and-trade.

Examples of other terminology changes include:

- 'Project Developers' changed to 'Offset Project Operators' or 'Authorized Project Designees';
- 'Avoidable' and 'Unavoidable' were changed to 'Intentional' and 'Unintentional';
- 'Buffer Pool' changed to 'Forest Buffer Account';
- 'GHG Assessment Boundary' changed to 'Offset Project Boundary';
- 'Project Start Date' changed to 'Offset Project Commencement';
- 'Annual Monitoring Report' changed to 'Offset Project Data Report', and the 'Project Design Document' requirements were incorporated into the initial offset project data report.

Permanence Mechanisms:
The definition of permanence was modified to align with the cap-and-trade regulation, which defines permanence as "...when GHG reductions or removal enhancements may be reversible, that mechanisms are in place to replace any reversed GHG emission reductions or removal enhancements to ensure that all credited reductions endure for a period that is comparable to the atmospheric lifetime of an anthropogenic CO2 emission." The permanence mechanisms currently in the protocol are designed to fulfill this requirement by ensuring that all crediting GHG reductions or removals are maintained for 100 years. No significant changes to the permanence mechanisms in the protocol were made,

except as related to the enforcement and administration of the permanence mechanisms.

CAR's Forest Protocol relies on a binding legal contract known as a Project Implementation Agreement (PIA) between the Forest Owner and CAR to identify a Forest Owner's obligations with respect to maintaining the permanence of credited reductions, as well as other project obligations. The PIA provides the basis for any enforcement action under CAR's program. References to CAR's Project Implementation Agreement have been removed from ARB's Forest Offset Protocol, as ARB will ensure compliance with protocol requirements through regulatory enforcement rather than through contracts. ARB staff determined that in a regulatory context a legal contract would not be necessary because as soon as an Offset Project Operator submits project information to ARB, they become subject to ARB's enforcement provisions.

ARB also modified the requirement to replace carbon released due to intentional reversals (including project termination) exclusively with other forest offsets. ARB will allow intentional reversals to be compensated for with any ARB-issued or approved compliance instruments (i.e. allowances or offset credits). CAR's protocol required that forest credits be only replaced with other forest offset credits to recognize the co-benefits of forest projects and the preferences of offset buyers in the voluntary market to ensure their investment remained in forest projects. However, ARB has concerns regarding the potential availability of forest offset credits in the event of a large intentional reversal such as project termination (where credits would need to be purchased in a single year to compensate for offsets that were potentially issued over many years). ARB also considers it important to maintain fungibility across all ARB compliance instruments in the cap-and-trade program.

Verification and Enforcement:
AB 32 specifically requires any greenhouse gas reductions used for compliance purposes to be verified and enforced through regulatory requirements adopted by ARB. The verification and enforcement requirements in the protocol have been revised align with ARB's regulatory requirements. The proposed cap and trade rule contains the requirements for a third-party offset verification process by ARB accredited verifiers, a conflict of interest review process, and regulatory requirements for providing verification services. Verification of offsets projects under ARB relies on the verification program requirements outlined in the regulation. The protocol was modified to reference ARB verification requirements and identify only specific verification tasks that must be conducted as part of or in addition to the regulatory requirements. Verification text in CAR's protocol was largely revised or removed, as much of the text included a restatement of protocol requirements and guidance on verifying those specific requirements. As ARB's verification program requires conformance will all protocol requirements, most of the CAR verification text that was removed will be incorporated into to a

future verification guidance document. Examples of specific verification requirements unique to forest projects detailed in the protocol include:

- Review of all project listing information during initial verification;
- Detailed review of forest carbon inventory program during each verification;
- Re-measurement and analysis of a selection of sample plots to ensure the sample plots used to develop the forest inventory were measured accurately;
- Review of conformance with natural forest management and sustainable harvesting provisions (non-conformance with these provisions will automatically result in an adverse verification statement);
- Requirement that each verification team include at least one Professional Forester that takes in active role in reviewing the forest carbon inventory program and conducting the site visit.

All mechanisms for the enforcement of forest project offsets are included in the proposed cap and trade regulation, and ARB will have oversight authority over the regulatory offset verification program. The regulation also specifies liabilities for the various parties participating in the cap and trade program. References to the Project Implementation Agreement in the protocol were removed, as regulatory enforcement will no longer be handled through contracts.

The Project Implementation Agreement also addressed the obligations of Forest Owners if project lands are sold. To address this in ARBs protocol, language was added to the 'Minimum Time Commitment' exceptions to specify that a Forest Project automatically terminates if Project Lands are sold to an entity that does not elect to take over project responsibilities and commitments. Such a termination is considered an intentional reversal and will require a quantity of compliance instruments equal to the amount of offset credits issued to the project over the previous 100 years (or the life of the project if less than 100 years) multiplied by the appropriate compensation rate (as applicable) to be retired.

Crediting Periods:
CAR's Forest Protocol currently employs a single crediting period of 100 years. The draft cap-and-trade regulation, however, requires a crediting period of 10-30 years for projects that involve carbon sequestration, with a possibility to renew at the end of each crediting period. ARB staff modified the protocol to include a crediting period of 25 years for forest projects, without any explicit limitation on the number of potential renewals. Monitoring, verification and replacement of all carbon lost through reversals is required for 100 years following the last issuance of any offset credits, consistent with the CAR's current protocol. Each project is required to move to the latest version of ARB's protocol at the end of the crediting period as a condition of renewal. It is ARB staff's expectation that forest projects will generally remain eligible for renewal provided that they transition to the latest compliance protocol as a condition of renewal. This ensures that all

projects use the latest factors, and reduces the number of versions of the protocol that could potentially be in use after a period of time to assist with project verification. For example, Forest Buffer Account contribution factors, and emissions leakage factors will likely be updated in the future as better information becomes available. Transitioning projects to the most recent approved protocol will help ensure that offset credits in ARB's program are quantified using the best available science, and reduce the administrative burden of having projects operating under many different versions of the Forest Offset Protocol as it is updated over the years.

Baseline adjustment for over-stocked private lands:
CAR's protocol includes a revised baseline approach to prevent selection bias in defining a project area that takes into consideration the existing carbon stocks on all of a Forest Owner's holdings within a logical management unit. A number of stakeholders have proposed a modification to this approach that would apply this adjustment only to relatively under-stocked areas, and not apply it to overstocked areas. This was intended to incentivize projects in mature forest stands that are perceived to be at greater risk of harvest. ARB staff has incorporated this proposal into the Forest Offset Protocol.

Specifically, the baseline approach for Improved Forest Management Projects on private lands has been modified so that projects with initial carbon stocks greater than the average stocking on all of a Forest Owner's (and its affiliate's) other lands within a logical management unit would receive some credit for avoiding the harvest of existing stocks. However, projects with carbon stocks that are at least 20 percent lower than the entity average within the same management unit must adjust their baseline to reflect management practices on the Forest Owner's other landholdings. This approach disallows project selection bias and crediting of non-additional carbon in the case of selecting areas with low stocking that would are expected to grow regardless of the project. However if project lands are selected due to their higher stocking, a baseline adjustment will not be required. While offset credits in this case would be issued for existing carbon stocks above the common practice benchmark, crediting higher stocked areas without a baseline adjustment provides an incentive to place older growth, high stocked areas into projects, resulting in the long-term protection of these forests and their associated co-benefits. Highly stocked areas are more likely to be at risk of harvest due to a greater quantity of merchantable timber, and as a result, projects that ensure carbon stocks in older growth areas will be maintained and increased are considered to be additional to business as usual.

Project Aggregation:
CAR's Protocol incorporates by reference guidelines for the aggregation of small forest projects. Aggregation rules are intended to encourage small landowner participation by reducing forest inventory and verification requirements and costs for individual Forest Owners that participate, while still maintaining the same high

degree of inventory accuracy for the aggregated projects as a whole. At this time ARB staff is not including project aggregation in the Forest Offset Protocol. ARB staff recognizes the significant potential benefits for the environment and offset supply of lowering barriers to participation for small Forest Owners. However, as aggregation rules were a very recent addition to CAR's protocol, ARB staff has not yet worked through the details of its compatibility within the compliance offset program, and any modifications that may be needed for aggregation to function within ARB's program.

Projects on Federal Lands:
ARB's Forest Offset Protocol allows for the eligibility of projects on public lands, and the protocol can readily be applied to projects on state and local government owned forest lands. However, projects on federal lands present an added level of complexity that requires further study before ARB will be able to accept projects on federal lands.

CAR's Forest Protocol requires approval by government agencies with responsibility for forest management activities for all projects on public lands, and specifically for federal lands it states, "projects on federal lands may be eligible if and when their eligibility is approved through a federal legislative or regulatory/rulemaking process." In ARB's Forest Offset Protocol, the provision on federal land eligibility has been removed until the technical and policy contexts of these projects are better understood. ARB staff recognizes the large potential for emission reductions and removals on federal forest lands, but feels that offset projects on federal lands would necessitate further review and potential revisions to the protocol at a later point.

Exclusion of Optional Carbon Pools:
To maintain consistency in project accounting and reporting, and because the methodologies for many of the optional pools are less standardized and carry with them more uncertainty, optional pools have been excluded from project accounting. Standardizing all carbon pools to be either required or excluded will increase accounting consistency and limit crediting to carbon pools that have a significant impact on the project accounting and are more readily quantifiable. References to optional pools, including the inventory requirements for those pools, have been removed.

Documentation Required for a Forest Carbon Inventory:
The CAR protocol requires Forest Owner's to develop and describe a methodology to sample for biomass or volume of all required carbon pools. While the protocol includes guidance and reference documents for developing the inventory methods for the various carbon pools, and specified requirements for inventory accuracy based on sampling error, Forest Owners are given discretion in developing their inventory program and methodologies subject to verifier approval. In order to provide more guidance to Forest Owners and

ensure that forest inventory methodologies are readily verifiable, ARB staff has expanded some of the guidelines in Appendix A – Developing an Inventory of Forest Project Carbon Stocks. The purpose of these modifications is to ensure transparency and consistency in the documentation of forest carbon inventory programs, which will in turn make the programs more readily verifiable. This is not so much a change to existing protocol requirements (as most of these items are already required by the protocol), as a clarification of expectations for documenting a forest carbon inventory program. ARB will require all forest projects to develop a documented forest carbon inventory program that explicitly includes:

- Description of project boundary, including a list of all included carbon pools;
- Description of the inventory sampling methodology used to quantify each carbon pool, with references clearly documented;
- Standard procedures for the collection of field measurements that include a description of the types of sample plots, location of plots, and frequency for updating or replacing sample plots;
- Standard procedures for where and how to measure parameters used in biomass calculations such as dbh and height (including for irregular trees);
- Documentation of inventory stratification rules, if applicable;
- Documentation of all analytic methods and biomass equations used to translate field measurements into volume or biomass carbon estimates;
- Documented quality assurance / quality control (QA/QC) plan that includes procedures for assessing and ensuring the quality of collection, transfer and archiving of field data, data entry and analysis, and any other relevant procedures to ensure quality and consistency in the collection and maintenance of data used to compile offset project data reports;
- Description of data management systems and processes, including the collection, storage and analysis of inventory related data analytical methods to translate field measurements into volume and/or biomass estimates;
- A change log documenting any changes in the inventory methods or equations used to calculate carbon stocks;
- Standard procedures for updating the forest carbon inventory, including documented procedures to account for harvest, growth, and disturbance; incorporation of new inventory and plot data, and retiring older sample plots; use of modeling, and application of appropriate confidence deduction.

The forest carbon inventory program will be reviewed by a verifier in detail during verification, and will be made available to ARB upon request. In determining requirements for a forest carbon inventory program, ARB staff consulted recent guidance produced by CAR on developing forest carbon inventories that had not previously been incorporated into the protocol. ARB staff also incorporated some

of the recommendations included in a 2004 report prepared by Winrock International for the California Energy Commission's PIER Program entitled "Methods for Measuring and Monitoring Forestry Carbon Projects in California."

Sample Plot Age Requirement:
ARB's Forest Offset Protocol requires that all sample plot data used to develop and update the forest carbon inventory have been sampled within the last twelve years. The protocol includes flexibility allowing varying sampling approaches, from sampling all plots once every twelve years to sampling a twelfth of the plots used to develop the inventory each year, so long as no plot data is older than twelve years. In the interim years, forest carbon models may be used to update the inventory. The CAR protocol contained an exception that allowed plot measurements to be up to 18 years old when Forest Owners could demonstrate that the process used to update the inventory adequately estimates the forest carbon inventory. ARB staff has removed this exception in the Forest Offset Protocol. ARB staff believes that relying on forest inventory modeling for too long increases the uncertainty of carbon stock estimates, and that 12 years should provide sufficient time to update sample plots.

Clarification of Promotion of Onsite Standing Live Carbon Stocks Requirement
ARB staff added several sentences to the section of the protocol requiring promotion of onsite standing live carbon stocks. ARB staff do not view this modification as a change to existing requirements, but rather as a clarification of the existing requirement to that all projects must maintain and increase standing live carbon stocks over the life of the projects. Specifically, over any consecutive 10 year period, projects must indicate an increase in standing live carbon stocks. There are four exceptions to this requirement that indicate under what circumstances a project's standing live carbon stocks may decrease, such as an unintentional reversal or temporary decreases that are part of normal silvicultural cycles on smaller project areas.

To the exceptions based on either a planned balancing of age classes or normal silvicultural cycles, ARB added the sentence, "Over any consecutive 10-year period, average standing live carbon stocks must be maintained at or above the standing live carbon stocks at the initiation of the project." This clarifies the intent of the requirements in this section by clearly not allowing a planned balancing of age classes to fall below initial carbon stocks (for example, if initial carbon stocks started above the project baseline and common practice). Also, the language was clarified that the requirement that, "At no time shall the Forest Project's inventory of standing live carbon stocks fall below the Forest Project's baseline standing live carbon stocks, or 20 percent less than the Forest Project's standing live carbon stocks at the project's initiation, whichever is higher," applies to a planned balancing of age classes as well as to normal silvicultural operations.

IV. References

CAR (2010) Forest Project Protocol Version 3.2. August 21, 2010. http://www.climateactionreserve.org/wpcontent/uploads/2009/03/Forest_Project_Protocol_Version_3.2.pdft/ (accessed September 9, 2010)

California Environmental Protection Agency

AIR RESOURCES BOARD

Compliance Offset Protocol for Forest Projects

Adopted: [INSERT Date of Board Adoption]

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Abbreviations and Acronyms

ARB	Air Resources Board
C	Carbon
CH_4	Methane
CO_2	Carbon dioxide
FIA	Forest Inventory and Analysis Program of the U.S. Forest Service
GHG	Greenhouse gas
lb	Pound
IFM	Improved Forest Management
N_2O	Nitrous oxide
Regulation	Cap-and-Trade Regulation, title 17, California Code of Regulations, sections 95800 et seq.
USFS	United States Forest Service

1 Introduction

The Compliance Offset Protocol for Forest Projects (Forest Offset Protocol) provides requirements and methods for quantifying the net climate benefits of activities that sequester carbon on forestland. The protocol provides project eligibility rules; methods to calculate a project's net effects on greenhouse gas (GHG) emissions and removals of CO_2 from the atmosphere (removals); procedures for assessing the risk that carbon sequestered by a project may be reversed (i.e. released back to the atmosphere); and approaches for long term project monitoring and reporting. The goal of this protocol is to ensure that the net GHG reductions and removals caused by a project are accounted for in a complete, consistent, transparent, accurate, and conservative manner and may therefore be reported as the basis for issuing Offset Credits. The protocol is built off of The Climate Action Reserve's Forest Project Protocol Version 3.2[1].

Offset Project Operators or Authorized Project Designees must use this protocol to quantify and report GHG reductions and removal enhancements. The protocol provides eligibility rules, methods to quantify reductions, project-monitoring instructions, and procedures for reporting offset project data reports. Additionally, all projects must submit to independent verification by ARB-accredited verification bodies. Requirements for verification bodies to verify offset project emissions data reports are provided in the Cap-and-Trade regulation (Regulation).

AB 32 exempts quantification methodologies from the Administrative Procedure Act (APA)[2], however those elements of the protocol are still regulatory. The exemption allows future updates to the quantification methodologies to be made through a public review and Board adoption process but without the need for rulemaking documents. Each protocol identifies sections that are considered quantification and exempt from APA requirements. Any changes to the non-quantification elements of the offset protocols would be considered a regulatory update subject to the full regulatory development process. Those sections that are considered to be a quantification methodology are clearly indicated in the title of the chapter or subchapter if only a portion of that chapter is considered part of the quantification methodology.

[1] CAR (2010) Forest Project Project Protocol Version 3.2. August 31, 2010. http://www.climateactionreserve.org/wpcontent/uploads/2009/03/Forest_Project_Protocol_Version_3.2.pdft/ (accessed September 9, 2010)

[2] Health and Safety Code section 38571.

1.1 About Forests, Carbon Dioxide, and Climate Change

Forests have the capacity to both emit and sequester carbon dioxide (CO_2), a leading greenhouse gas that contributes to climate change. Trees, through the process of photosynthesis, naturally absorb CO_2 from the atmosphere and store the gas as carbon in their biomass, i.e. trunk (bole), leaves, branches, and roots. Carbon is also stored in the soils that support the forest, as well as the understory plants and litter on the forest floor. Wood products that are harvested from forests can also provide long term storage of carbon.

When trees are disturbed, through events like fire, disease, pests or harvest, some of their stored carbon may oxidize or decay over time releasing CO_2 into the atmosphere. The quantity and rate of CO_2 that is emitted may vary, depending on the particular circumstances of the disturbance. Forests function as reservoirs in storing CO_2. Depending on how forests are managed or impacted by natural events, they can be a net source of emissions, resulting in a decrease to the reservoir, or a net sink, resulting in an increase of CO_2 to the reservoir. In other words, forests may have a net negative or net positive impact on the climate.

Through sustainable management and protection, forests can also play a positive and significant role to help address global climate change. The Forest Offset Protocol is designed to address the forest sector's unique capacity to sequester, store, and emit CO_2 and to facilitate the positive role that forests can play to address climate change.

2 Forest Project Definitions and Requirements

For the purposes of this protocol, a Forest Project is a planned set of activities designed to increase removals of CO_2 from the atmosphere, or reduce or prevent emissions of CO_2 to the atmosphere, through increasing and/or conserving forest carbon stocks.

A glossary of terms related to Forest Projects is provided in Section 11 of this protocol. Throughout the protocol, important defined terms are capitalized (e.g. "Reforestation Project").

2.1 Project Types

The following types of Forest Project activities are eligible:

2.1.1 Reforestation

A Reforestation Project involves restoring tree cover on land that is not at optimal stocking levels and has minimal short-term (30-years) commercial opportunities. A Reforestation Project is only eligible if it can fully satisfy the eligibility rules in the Regulation and:

1. The project involves tree planting or removal of impediments to natural reforestation, on land that:
    a. Has had less than 10 percent tree canopy cover for a minimum of 10 years; or
    b. Has been subject to a Significant Disturbance that has removed at least 20 percent of the land's above-ground live biomass in trees.
2. No rotational harvesting of reforested trees or any harvesting of pre-existing carbon in live trees occurs during the first 30 years after offset project commencement unless such harvesting is needed to prevent or reduce an imminent threat of disease. Such harvesting may only occur if the Offset Project Operator or Authorized Designee provides a written statement from the government agency in charge of forestry regulation in the state where the project is located stipulating that the harvesting is necessary to prevent or mitigate disease.
3. The tree planting, or removal of impediments to natural reforestation, does not follow a commercial harvest of healthy live trees that has occurred in the Project Area within the past 10 years, or since the occurrence of a Significant Disturbance, whichever period is shorter.
4. The project does *not* employ broadcast fertilization.
5. The project does not take place on land that was part of a previously listed and verified Forest Project, unless the previous Forest Project was terminated due to an Unintentional Reversal (see Section 7).

Reforestation Projects on both private and public lands, excluding federal lands, are eligible.

2.1.2 Improved Forest Management

An Improved Forest Management Project involves management activities that maintain and increase carbon stocks on forested land relative to baseline levels of carbon stocks, as defined in Section 6.2 of this protocol. An Improved Forest Management Project is only eligible if it can fully satisfy the eligibility rules in the Regulation and:

1. The project takes place on land that has greater than 10 percent tree canopy cover.
2. The project employs natural forest management practices, as defined in Section 3.8.2 of this protocol.
3. The project does *not* employ broadcast fertilization.

4. The project does not take place on land that was part of a previously listed and verified Forest Project, unless the previous Forest Project was terminated due to an Unintentional Reversal (see Section 7).

Eligible management activities may include, but are not limited to:

- Increasing the overall age of the forest by increasing rotation ages.
- Increasing the forest productivity by thinning diseased and suppressed trees.
- Managing competing brush and short-lived forest species.
- Increasing the stocking of trees on understocked areas.
- Maintaining stocks at a high level.

Improved Forest Management Projects on both private and public lands, excluding federal lands, are eligible.

2.1.3 Avoided Conversion

An Avoided Conversion Project involves preventing the conversion of forestland to a non-forest land use by dedicating the land to continuous forest cover through a Qualified Conservation Easement or transfer to public ownership, excluding transfer to federal ownsership. An Avoided Conversion Project is only eligible if it can fully satisfy the eligibility rules in the Regulation and:

1. It can be demonstrated that there is a significant threat of conversion of project land to a non-forest land use by following the requirements for establishing the project's baseline in Section 6.3 of this protocol.
2. The project does *not* employ broadcast fertilization.
3. The project does not take place on land that was part of a previously listed and verified Forest Project, unless the previous Forest Project was terminated due to an Unintentional Reversal (see Section 7).

An Avoided Conversion Project may involve tree planting and harvesting as part of the project activity.

Avoided Conversion Projects are eligible only on lands that are privately owned prior to offset project commencement.

2.2 Forest Owners

A Forest Owner is the owner of any interest in the property involved in a Forest Project, but does not include the holder of a conservation easement. Generally, a Forest Owner is the legal land owner (owner in fee) of the property involved in a Forest Project. In some cases, one entity may own the land while another entity may have an interest in the trees or the timber on the property, in which case all entities or individuals with interest in the property are collectively considered Forest Owners, however, a single Offset Project Operator must be identified.

The Offset Project Operator is responsible for undertaking, listing, and verifying a Forest Project, however, all Forest Owner(s) are ultimately responsible for all Forest Project commitments. The Offset Project Operator may identify an Authorized Project Designee pursuant to §95974 of the Cap-and-Trade Regulation, to assist or consult with implementation of the Forest Project. All information submitted to ARB or an Offset Registry shall reference the Offset Project Operator and all Forest Owner(s) who are ultimately responsible for the accuracy and completeness of the information submitted.

3 Eligibility Rules and Other Requirements

In addition to the definitions and requirements described in Section 2, Forest Projects must meet several other criteria and conditions to be eligible for listing, and must adhere to requirements in the Regulation and requirements related to duration and crediting periods.

3.1 Additionality

Eligible offsets must be generated by projects that yield surplus GHG emission reductions or removals that exceed any GHG reductions or removals otherwise required by law or regulation, or any GHG reduction or removal that would otherwise occur in a conservative Business-As-Usual Scenario. Forest Projects must satisfy the following to be considered additional:

1. Forest Projects must achieve GHG reductions or removals above and beyond any GHG reductions or removals that would result from compliance with any federal, state, or local law, regulation or ordinance. Forest Projects must also achieve GHG reductions and removals above and beyond any GHG reductions or removals that would result from compliance with any court order or other legally binding mandates, including management plans (such as Timber Harvest Plans) that are required for government agency approval of harvest activities. Legally binding mandates also include conservation easements or deed restrictions, except where such conservation easements have been enacted in support of the Forest Project, as described in Section 3.5. This requirement is assessed through the Legal Requirement Test in 3.1.1.
2. Forest Projects must achieve GHG reductions or removals above and beyond any GHG reductions or removals that would result from engaging in Business As Usual activities, as defined by the Regulation and the requirements described below (Section 3.1.2). This requirement is assessed through the Performance Test in Section 3.1.2.

3.1.1 Legal Requirement Test

To meet additionality requirements, the following legal requirement test must be met, specific to each type of Forest Project.

3.1.1.1 Reforestation Projects

Reforestation Project activities cannot be legally required (as defined above) at the time of offset project commencement. Modeling of the project's baseline carbon stocks must reflect all legal constraints, as required in Section 6.1 of this protocol.

3.1.1.2 Improved Forest Management Projects

Improved Forest Management Project activities (defined as management activities intended to maintain or increase carbon stocks relative to baseline levels) cannot be legally required (as defined above) at the time of offset project commencement. Modeling of the project's baseline carbon stocks must reflect all legal constraints, as required in Section 6.2 of this protocol.

3.1.1.3 Avoided Conversion Projects

Avoided Conversion Project activities cannot be legally required (as defined above) at the time of offset project commencement. Modeling of the project's baseline carbon stocks must reflect all legal constraints, as required in Section 6.3 of this protocol.

Official documentation must be submitted demonstrating that the type of anticipated land use conversion is legally permissible. Such documentation must fall into at least one of the following categories:

1. Documentation indicating that the current land use policies, including zoning and general plan ordinances, and other local and state statutes and regulations, permit the anticipated type of conversion.
2. Documentation indicating that the Forest Owner(s) obtained all necessary approvals from the governing county to convert the Project Area to the proposed type of non-forest land use (including, for instance, certificates of compliance, subdivision approvals, timber conversion permits, other rezoning, major or minor use permits, etc.)
3. Documentation indicating that similarly situated forestlands within the project's Assessment Area were recently able to obtain all necessary approvals from the governing county, state, or other governing agency to convert to a non-forest land use (including, for instance, certificates of compliance, subdivision approvals, timber conversion permits, other rezoning, major or minor use permits, etc.)

3.1.2 Performance Test

The performance test is satisfied if the following requirements are met, depending on the type of Forest Project.

3.1.2.1 Reforestation Projects

A Reforestation Project that occurs on land that has had less than 10 percent tree canopy cover for at least 10 years automatically satisfies the performance test.

A Reforestation Project that occurs on land that has undergone a Significant Disturbance satisfies the performance test if:

1. The Forest Project corresponds to a scenario in Appendix E, Table E.1, indicating that it is "eligible" (as determined by the requirements and methods in Appendix E); or
2. The Forest Project occurs on a type of land for which the Forest Owner has not historically engaged in or allowed timber harvesting. (Examples of such land include municipal or state parks.)

3.1.2.2 Improved Forest Management Projects

An Improved Forest Management Project automatically satisfies the performance test. Project activities are considered additional to the extent they produce GHG reductions and/or removals in excess of those that would have occurred under a conservative Business As Usual Scenario, as defined by the baseline estimation requirements in Section 6.2.1.

3.1.2.3 Avoided Conversion Projects

An Avoided Conversion Project satisfies the performance test if a real estate appraisal for the Project Area (as defined in Section 4) is submitted indicating the following:

1. *The Project Area is suitable for conversion.* The appraisal must clearly identify the highest value alternative land use for the Project Area and indicate how the physical characteristics of the Project Area are suitable for the alternative land use.
    a. At a minimum, where conversion to commercial, residential, or agricultural land uses is anticipated, the appraisal must indicate that the slope of Project Area land does not exceed 40 percent.
    b. Where conversion to agricultural land use is anticipated, the appraisal must provide:

i. Evidence of soil suitability for the type of expected agricultural land use.
ii. Evidence of water availability for the type of expected agricultural land use.

c. Where conversion to mining land use is anticipated, the appraisal must provide evidence of the extent and amount of mineral resources existing in the Project Area, and the commercial viability of mineral extraction.
d. The appraisal must identify specific portions of the Project Area suitable for the identified alternative land use. For example, an appraisal that identified a golf course as an alternative land use must specify the approximate acres suitable for fairways, greens, clubhouses, and outbuildings.

2. *The alternative land use for the Project Area has a higher market value than forestland.* The appraisal for the property must demonstrate that the fair market value of the anticipated alternative land use for the Project Area is at least 40 percent greater than the value of the current forested land use.

Where conversion to residential, commercial, or recreational land uses is anticipated, the appraisal must also describe the following information:

1. The proximity of the Project Area to metropolitan areas.
2. The proximity of the Project Area to grocery and fuel services and accessibility of those services.
3. Population growth within 180 miles of the Project Area.

The appraisal must be conducted in accordance with the Uniform Standards of Professional Appraisal Practice[3] and the appraiser must meet the qualification standards outlined in the Internal Revenue Code, Section 170 (f)(11)(E)(ii).[4]

3.2 Offset Project Commencement

The date of offset project commencement for a Forest Project is the date on which an activity is first implemented that will lead to increased GHG reductions or removals relative to the Forest Project's baseline. The following actions identify offset project commencement for each project type:

- For a Reforestation Project, the action is the planting of trees, the removal of impediments to natural regeneration, or site preparation for the planting of trees, whichever comes first.
- For an Improved Forest Management Project, the action is initiating forest management activities that increase sequestration and/or decrease emissions relative to the baseline, or transferring the Project Area to public ownership.
- For an Avoided Conversion Project, the action is committing the Project Area to continued forest management and protection through recording a conservation easement with a provision to maintain the Project Area in forest cover or transferring the Project Area to public ownership.

[3] Uniform Standards of Professional Appraisal Practice. http://www.uspap.org/2010USPAP/toc.htm. Accessed 10/01/2010

[4] Section 170 (f)(11)(E)(ii) of the Internal Revenue Code defines a qualified appraiser as "an individual who -
(I) has earned an appraisal designation from a recognized professional appraiser organization or has otherwise met minimum education and experience requirements set forth in regulations prescribed by the Secretary,
(II) regularly performs appraisals for which the individual receives compensation, and
(III) meets such other requirements as may be prescribed by the Secretary in regulations or other guidance."

An Improved Forest Management project's offset project commencement date must be linked to a discrete, verifiable action that delineates a change in practice relative to the project's baseline..One of the following actions denote an Improved Forest Management project's commencement date:

- Recordation of a conservation easement on the Project Area. The date the easement was recorded is the project's commencement date.
- Transferring of property ownership (to a public or private entity). The project commencement date is the date of property transfer.
- Submitting the project listing information specified in Section 9.1.1. Offset project commencement is the date of submittal of listing information, provided that the project completes verification within 30 months of being submitted. If the project does not meet this deadline, the listing information must be resubmitted under the latest version of the protocol.

Adequate documentation denoting the offset project commencement date must include where applicable; deeds of trust, title reports, conservation easement documentation, dated forest management plans, and/or other relevant contracts or agreements.

3.3 Project Crediting Period

The baseline for any Forest Project under this version of the Forest Offset Protocol is valid until the end of the crediting period following a successful initial verification where the project receives a positive or qualified positive verification statement. This means that after a successful initial verification, a Forest Project will be eligible to receive Offset Credits for GHG reductions and/or removals quantified using this protocol, and verified by ARB-approved verification bodies, for a period of 25 years following the offset project's commencement date. A project may be renewed for subsequent crediting periods, subject to approval at that time and use of the quantification methods in the most recent approved version of the Forest Offset Protocol at the time of renewal. Projects must be listed within 6 months of the offset project commencement date.

3.4 Project Life and Minimum Time Commitment

Project Life is defined as the period of time between offset project commencement and a period of 100 years following the issuance of any Offset Credit for GHG reductions or removal enhancements achieved by the project. Forest Projects must continue to monitor, verify and report project data for a period of 100 years following any Offset Credit issuance. For example, if Offset Credits are issued to a Forest Project in year 25 following offset project commencement, monitoring and verification activities must be maintained until year 125. All Forest Projects must undergo an initial verification that includes a site visit before a project may be issued Offset Credits. After the initial verification all Forest Projects must undergo verification at least once every six years. The only exception to this rule is for Reforestation Projects, which may defer a second verification for up to 12 years. The third and subsequent verifications for Reforestation Projects must continue on at least a six-year cycle.

There are three possible exceptions to this minimum time commitment:

1. A Forest Project automatically terminates if a Significant Disturbance occurs leading to an Unintentional Reversal that reduces the project's Standing Live Carbon Stocks below the project's baseline Standing Live Carbon Stocks. Once a Forest Project terminates in this manner, there are no further obligations under this protocol.

2. A Forest Project automatically terminates if Project Lands are sold to an entity that does not elect to take over the Forest Project responsibilities and commitments. Such a termination will require a quantity of Offset Credits to be retired, as specified under 'Retiring Compliance Instruments Following Project Termination,' below.
3. A Forest Project may be voluntarily terminated prior to the end of its minimum time commitment if the required quantity of Compliance Instruments are retired, as specified under 'Retiring Compliance Instruments Following Project Termination,' below.

Retiring Compliance Instruments Following Project Termination

a. For a Reforestation or Avoided Conversion Project, a quantity of Compliance Instruments equal to the total number of Offset Credits issued to the project over the 100 years must be retired.
b. For an Improved Forest Management Project, a quantity of Compliance Instruments equal to the total number of Offset Credits issued to the project over the preceding 100 years, multiplied by the appropriate compensation rate indicated in Table 3.1 must be retired.

Table 3.1. Compensation Rate for Terminated Improved Forest Management Projects

Number of years that have elapsed between offset project commencement and the date of termination	Compensation Rate
0-5	1.40
6-10	1.20
11-20	1.15
21-25	1.10
31-50	1.05
>50	1.00

3.5 Use of Qualified Conservation Easements

For Avoided Conversion Projects on private land, the Forest Owner must record a Qualified Conservation Easement against the project's property in order for the Forest Project to be eligible. To be "qualified" for purposes of ARB's compliance offset program, the conservation easement must:

a. Be granted by the owner of the fee to a qualified holder of a conservation easement in accordance with the conservation easement enabling statute of the state in which the project is located;
b. Be perpetual in duration;
c. Expressly acknowledge that ARB is a third party beneficiary of the conservation easement with the right to enforce all obligations under the easement and all other rights and remedies conveyed to the holder of the easement. These rights include standing as an interested party in any proceeding affecting the easement.

Qualified Conservation Easements must be recorded no earlier than one year before the offset project's commencement date. If a Qualified Conservation Easement was recorded more than

one year prior to the offset project commencement date, the limits imposed by the easement on forest management activities must be considered a legal mandate for the purpose of satisfying the legal requirement test for additionality (Section 3.1.1) and in determining the project's baseline (Section 6).

As indicated in Section 3.2, an offset project commencement date must be linked to a discrete, verifiable action. The recordation of a conservation easement may be used to denote the commencement date of pre-existing projects between December 31, 2006 and December 31, 2010. Any previously recorded conservation easement may only be considered a Qualified Conservation Easement if it was recorded within one year prior to the identified project commencement date. Any previously recorded conservation easement must still meet, or be modified to meet, all of the requirements of this section (i.e. expressly acknowledging ARB as a third-party beneficiary) in order to be considered "qualified".

3.6 Project Location

All Forest Projects must be located in the United States of America. Reforestation Projects and Improved Forest Management Projects may be located on private land, or on state or municipal public land. Avoided Conversion Projects must be implemented on private land, unless the land is transferred to public ownership as part of the project.

All Forest Projects on public lands must be approved by the government agency or agencies responsible for management activities on the land. This approval must include an explicit approval of the project's baseline, as determined in Section 6, and must involve any public vetting processes necessary to evaluate management and policy decisions concerning the project activity. Projects on federal lands are not eligible at this time.

Forest Projects in tribal areas must demonstrate that the land within the Project Area is owned by a tribe or private entities.

The Forest Offset Protocol contains data tables, equations, and benchmark data applicable to projects located in the United States. The methods required by this protocol for estimating baseline carbon stocks for Forest Projects cannot currently be applied outside the United States, as they rely on U.S.-specific data sets and models. Improved Forest Management Projects in Alaska and Hawaii are not eligible at this time due to lack of region-specific data.

3.7 Regulatory Compliance

As stated in the Regulation, Project Lands must fulfill all applicable local, regional and national requirements on environment impact assessments that apply based on the offset project location. Projects must also meet any other local, regional, and national requirements that might apply.

Each time the Forest Project is verified, the Offset Project Operator or Authorized Project Designee must attest that the Forest Owner and Project Lands are in compliance with all applicable laws and regulations. The Offset Project Operator or Authorized Project Designee are required to disclose in writing to the verifier any and all instances of non-compliance associated with the Project Lands with any legal requirement. If a verifier finds that a project is in a state of non-compliance with any environmental law or regulation, then Offset Credits will not be issued for GHG reductions that occurred during any calendar year period of non-compliance.

3.8 Sustainable Harvesting and Natural Forest Management Practices

Forest Projects can create long-term climate benefits as well as provide other environmental benefits, including the sustaining of natural ecosystem processes. This protocol requires eligible projects to employ both sustainable long-term harvesting practices and Natural Forest Management practices over time, as described below. Any non-conformance with the sustainable harvesting and Natural Forest Management requirements in this section will result in an adverse verification statement during the calendar years that the Forest Project was out of conformance.

3.8.1 Sustainable Harvesting Practices

At the time commercial harvesting is either planned or initiated within the Project Area, the Offset Project Operator or Authorized Project Designee must demonstrate that the Forest Owner(s) employ and demonstrate sustainable long-term harvesting practices on all of its forest landholdings, including the Project Area, using one of the following options:

1. The Forest Owner must be certified under the Forest Stewardship Council, Sustainable Forestry Initiative, or Tree Farm System certification programs. Regardless of the program, the terms of certification must require adherence to and verification of harvest levels which can be permanently sustained over time.
2. The Forest Owner must adhere to a renewable long-term management plan that demonstrates harvest levels which can be permanently sustained over time and that is sanctioned and monitored by a state or federal agency.
3. The Forest Owner must employ uneven-aged silvicultural practices (if harvesting occurs) and must maintain canopy cover averaging at least 40 percent across the entire forestland owned by the Forest Owner in the same Assessment Areas covered by the Project Area, as measured on any 20 acres within the Forest Owner's landholdings found in any of these Assessment Areas, including land within and outside of the Project Area (areas impacted by Significant Disturbance may be excluded from this test).

Forest Owners who acquire new forest landholdings within their entity have up to 5 years to incorporate such acquisitions under their certification or management plan, whether or not such land is contiguous with the Project Area.

3.8.2 Natural Forest Management

All Forest Projects must promote and maintain a diversity of native species and utilize management practices that promote and maintain native forests comprised of multiple ages and mixed native species within the Project Area and at multiple landscape scales ("Natural Forest Management").

All Forest Projects are required to establish and/or maintain forest types that are native to the Project Area. For the purposes of this protocol, native forests are defined as those forests occurring naturally in an area, as neither a direct nor indirect consequence of human activity post-dating European settlement.

Forest Offset Protocol Resources section of ARB's webpage provides required references by Assessment Area for the definition of native forests (see Appendix F). If a state/regional reference is unavailable or inadequate, documentation from a state botanist or other qualified independent resource, recognized as expert by academic, private and government organizations, must be submitted indicating that the project promotes and maintains native

forests per the definition above. Where supported by scientific peer-reviewed research, the planting of native species outside of their current distribution is allowed as an adaptation strategy due to climate change. Such planting must be done in accordance with a state or federally approved adaptation plan, or a local plan that has gone through a transparent public review process. A written statement must be submitted from the government agency in charge of forestry regulation in the state where the project is located stipulating that the planting of native trees outside their current range is appropriate as an adaptation to climate change.

The following requirements shall apply to all Forest Projects regardless of the silvicultural or regeneration methods that are used to manage or maintain the forest:

1. Forest Projects must maintain or increase standing live carbon stocks over the project life, as described in Section 3.8.3.
2. Forest Projects must show verified progress (verified at scheduled site-visits) towards native tree species composition and distribution consistent with the forest type and forest soils native to the Assessment Area.
3. Forest Projects must manage the distribution of habitat/age classes and structural elements to support functional habitat for locally native plant and wildlife species naturally occurring in the Project Area, as specified in Table 3.2 and Section 3.8.4 below.

Forest Projects that initially engage in Natural Forest Management must continue to do so for as long as monitoring and verification of the Forest Project are required by this protocol (i.e. for the duration of the Project Life). Forest Projects that do not initially meet Natural Forest Management criteria but can demonstrate progress towards meeting these criteria at the times identified in Table 3.2 are still eligible.

The evaluation criteria provided in Table 3.2 shall be used to determine if the Forest Project meets the criteria for engaging in Natural Forest Management. The following evaluation must be completed and verified at a Forest Project's first verification and at all subsequent verifications. Forest Project carbon stock inventories (requirements for which are contained in Appendix A) should be used as the basis of these assessments where applicable.

Table 3.2. Evaluation criteria to test if a Forest Project meets the requirement for the establishment and maintenance of native species and natural forest management

Criteria	When Assessed	Results of not passing criteria	Application Rules
Native Species			
Project consists of at least 95% native species based on the sum of carbon in the standing live carbon pool. The assessment shall be conducted using estimates of stems per acre for Reforestation Projects and basal area per acre for Improved Forest Management and Avoided Conversion Projects.	Assessed at initial verification from inventory data.	Forest Project is not eligible unless demonstrated that management will achieve this goal over the project life.	Applies to all project types throughout the project life
	Assessment during verification site visits must demonstrate continuous progress toward goal. This criterion must be met within 25 years.	Project is not in conformance with protocol requirements.	
Composition of Native Species			
Improved Forest Management and Avoided Conversion Projects Where the Project Area naturally consists of a mixed species distribution, no single species'	Species composition is assessed at project initiation from inventory data.	Project is not eligible, unless it is demonstrated that management activities will enable this goal to be achieved over the project life.	Applies to all project types throughout the project life

prevalence, measured as the percent of the basal area of all live trees in the Project Area, exceeds the percentage value of standing live carbon shown under the heading 'Species Diversity Index' in Forest Offset Protocol Resources section of ARB's website. Where the Project Area does not naturally consist of a mixed species distribution, a written statement from the government agency in charge of forestry regulation in the state where the project is located stipulating that the project area does not naturally consist of a mixed species distribution must be submitted. **Reforestation** To the extent seed is available, and/or physical site characteristics permit, Reforestation Projects that involve planting of seedlings must plant a mixture of species such that no single species' prevalence, measured as the percent of all live tree stems in the Project Area, exceeds the percentage value shown under the heading 'Species Diversity Index' in the Assessment Area table in Forest Offset Protocol Resources section of ARB's website. Where seed is unavailable, the Reforestation Project is based on natural regeneration, or physical site characteristics are limiting, a written statement from the government agency in charge of forestry regulation in the state where the project is located stipulating that seed is unavailable, the Reforestation Project is based on natural regeneration, or physical site characteristics are limiting must be submitted.	Species composition is assessed at initial verification from inventory data. Project must show continuous progress toward criteria. These criteria must be met within 25 years.	Project is not in conformance with protocol requirements.	Some project sites may not be capable of meeting the requirement. In these cases, a written statement from the government agency in charge of forestry regulation in the state where the project is located must be submitted as described under "Criteria"
Distribution of Age Classes/Sustainable Management			
All forest landholdings owned or controlled by the Forest Owner are currently under one of the following: 1. Third party certification under the Forest Stewardship Council, Sustainable Forestry Initiative, or Tree Farm System, whose certification standards require adherence to and verification of harvest levels which can be permanently sustained over time, or 2. Operating under a renewable long-term management plan that demonstrates harvest levels which can be permanently sustained over time and that is sanctioned and monitored by a state or federal agency, or 3. The Forest Owner must employ uneven-aged silvicultural practices and canopy retention averaging at least 40 percent across the forest, as measured on any 20 acres within the entire forestland owned by the Forest Owner, including land within and outside of the Project Area. (Areas impacted by Significant Disturbance may be excluded from this test.)	Condition shall be met at all times during project and is assessed during each verification.	Project is not in conformance with protocol requirements.	Applies to all project types at first regeneration harvest
On a watershed scale up to 10,000 acres (or the project area, whichever is smaller), all projects must maintain, or make progress toward maintaining, no more than 40 percent of their forested acres in ages less than 20 years. (Areas impacted by Significant	Age classes (if even age management is used) are assessed at project initiation and each verification site visit.	NA	

Disturbance may be excluded from this test.)	Project must show continuous progress toward criteria. This criterion must be met within 25 years.	Project is not in conformance with protocol requirements.	
Structural Elements (Standing and Lying Dead Wood)			
Lying dead wood must be retained in sufficient quantities, as described below. **For portions of the Project Area that have not recently undergone salvage harvesting:** If a verifier determines that the quantity of lying dead wood is commensurate with recruitment from standing dead trees (i.e. there is no evidence that lying dead wood has been actively removed), the project must maintain (or demonstrate ongoing progress toward) an average of at least: ▪ one (1) metric ton of carbon (C) per acre; or ▪ 1% of standing live carbon stocks, in *standing* dead wood, whichever is higher, If a verifier determines that the quantity of lying dead wood is **not** commensurate with recruitment from standing dead trees (i.e. it appears lying dead wood has been actively removed), the project must maintain (or demonstrate ongoing progress toward) an average of at least: ▪ two (2) metric tons of carbon (C) per acre; or ▪ 1% of standing live carbon stocks, in *standing* dead wood, whichever is higher, Standing dead wood may be evenly or unevenly distributed throughout the portion of the Project Area unaffected by salvage harvesting, as long as the appropriate minimum average tonnage per acre requirement is met. **For portions of the Project Area that have undergone salvage harvesting within the previous year:** If a verifier determines that the quantity of lying dead wood following salvage harvest is commensurate with recruitment from standing dead trees, the project must maintain (or demonstrate ongoing progress toward) an average of at least two (2) metric tons of carbon (C) per acre in *standing* dead wood, If a verifier determines that the quantity of lying dead wood following harvest is **not** commensurate with recruitment from standing dead trees, the project must maintain (or demonstrate ongoing progress toward) an average of at least four (4) metric tons of carbon (C) per acre in *standing* dead wood, Standing dead wood may be evenly or unevenly distributed throughout the portion of the Project Area subject to salvage harvesting, as long as the appropriate minimum average tonnage per acre requirement is met. This requirement must be met for a period of 30 years following the salvage harvest. After 30 years, the portion of the Project Area subject to salvage harvesting must meet the requirements for portions	Assessed during project at each verification audit.	Project is not in conformance with protocol requirements.	Applies to all project types throughout the project life

that have not recently undergone salvage harvesting (described above).			

3.8.3 Promotion of the Onsite Standing Live Carbon Stocks

In an effort to promote and maintain the environmental benefits of Forest Projects, the standing live carbon stocks within the Project Area must be maintained and/or increased during the Project Life. Therefore, except as specified below, Offset Credits will not be issued for quantified GHG reductions and removals achieved by a Forest Project if a Forest Project's Offset Project Data Reports – over any 10-year consecutive period – indicate a decrease in the standing live carbon stocks.

Exceptions are allowed where reductions in standing live carbon stocks are important for maintaining and enhancing forest health, environmental co-benefits, or the long-term security of all carbon stocks; where reductions are due to non-harvest disturbances; or where reductions are required by law. Note that these exceptions in no way change or affect the requirements related to compensating for reversals, as detailed in Section 7.3.

Forest Projects whose standing live carbon stocks have decreased over a 10-year period are not in conformance with protocol requirements, except if the decrease in standing live carbon stocks is due to one of the following causes:

1. The decrease is demonstrably necessary to substantially improve the Project Area's resistance to wildfire, insect, or disease risks. The actions that will be taken to reduce the risks must be documented. The techniques used to improve resistance must be supported by relevant published peer reviewed research.
2. The decrease is associated with a planned balancing of age classes (regeneration, sub-merchantable, and merchantable) and is detailed in a long-term management plan that demonstrates harvest levels can be permanently sustained over time and that is sanctioned and monitored by a state or federal agency. In this case, documentation must be submitted at the time of the Forest Project's Listing, indicating that a balancing of age classes, resulting in a decrease in the standing live carbon stocks, is planned at the initiation of the Forest Project (Figure 3.1). At no time over the Project Life shall the Forest Project's inventory of standing live carbon stocks fall below the Forest Project's baseline standing live carbon stocks, or 20 percent less than the Forest Project's standing live carbon stocks at the project's initiation, whichever is higher. Over any consecutive 10-year period, average standing live carbon stocks must be maintained at or above the standing live carbon stocks at the initiation of the project.

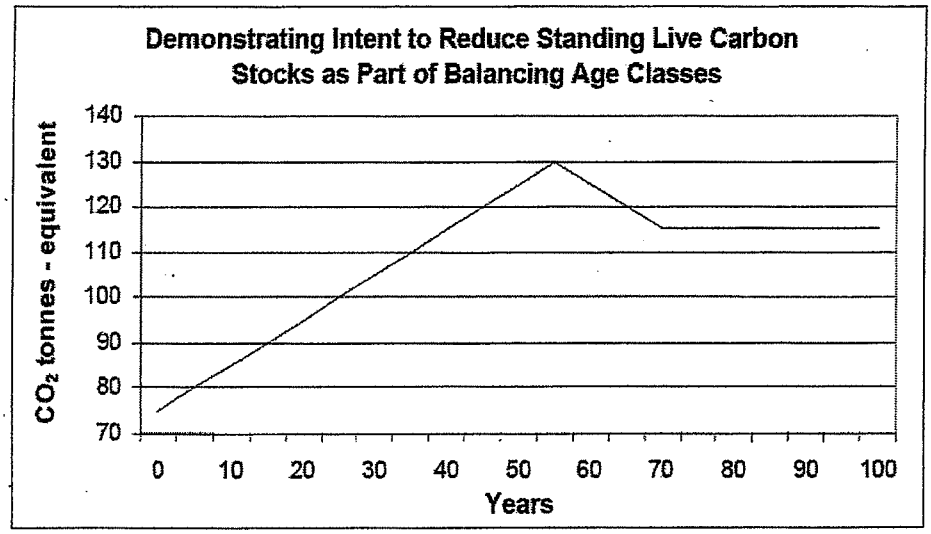


Figure 3.1. Example of Reducing Standing Live Carbon Stocks as Part of Balancing Age Classes

3. The decrease is part of normal silviculture cycles for forest ownerships less than 1,000 acres. Inventory fluctuations are a normal part of silvicultural activities. Periodic harvest may remove more biomass than the biomass growth over the past several years. At no time during the Project Life shall the Forest Project's inventory of standing live carbon stocks fall below the Forest Project's baseline standing live carbon stocks, or 20 percent less than the Forest Project's standing live carbon stocks at the project's initiation, whichever is higher. Over any consecutive 10-year period, average standing live carbon stocks must be maintained at or above the standing live carbon stocks at the initiation of the project. Documentation submitted at the time the Forest Project is Listed must indicate that fluctuations in the Forest Project's standing live carbon stocks are an anticipated silvicultural activity and that the overall trend will be for standing live carbon stocks to increase or stay the same over the life of the project (Figure 3.2).

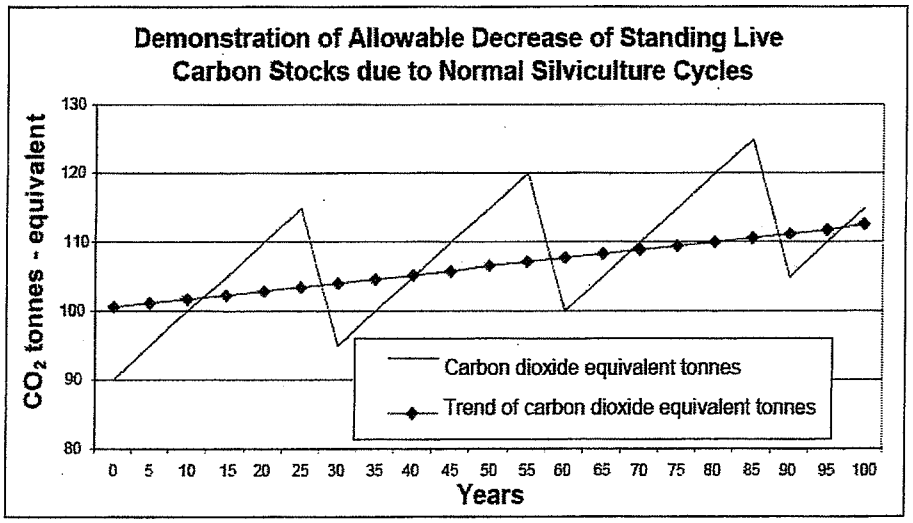


Figure 3.2. Example of Allowable Decrease of Standing Live Carbon Stocks due to Normal Silviculture Cycles

4. The decrease is due to an unintentional reversal such as wildfire, disease, flooding, wind-throw, insect infestation, or landslides.

3.8.4 Balancing Age and Habitat Classes

A variety of silvicultural practices may be employed in the Project Area during the course of a Forest Project though the protocol does not endorse any particular practice. To ensure environmental integrity, Forest Projects must meet a minimum set of standards in the use of any such practices.

For projects that employ even-aged management practices, harvesting must be limited to stands no greater than 40 acres. Stands adjacent to recently harvested stands must not be harvested using an even-aged harvest until the average age of the adjacent stand is at least 5-years old, or the average height in the adjacent stand is at least 5 feet. On a watershed scale up to 10,000 acres, all projects must maintain, or make progress toward maintaining, no more than 40 percent of their forested acres in ages less than 20 years. Areas impacted by a Significant Disturbance are exempt from this test until 20 years after reforestation of such areas.

The protocol does not override a landowner's obligation to abide by applicable laws and regulations, including any governing forest practice rules that may be more stringent. Regardless of the silvicultural practice employed, landowners must fulfill their commitment under the protocol to permanently maintain or increase onsite standing live carbon stocks (i.e. the carbon in live trees within the Project Area) as specified in Section 3.8.3.

4 Identifying the Project Area

The geographic boundaries defining the Project Area must be described in detail at the time a Forest Project is Listed. The boundaries must be defined using a map, or maps, that display public and private roads, major watercourses (4th order or greater), topography, towns, and either public land survey townships, ranges, and sections or latitude and longitude. The maps must be of adequate resolution to clearly identify the required features. The Project Area can be contiguous or separated into tracts. The Project Area may also extend across multiple Assessment Areas within an Ecosection or Supersection (see Appendix F) and across no more than two adjacent Ecosections or Supersections.

For Improved Forest Management Projects, the geographic boundaries may be defined such that non-forested areas, or areas not under forest management, are excluded from the Project Area.

For Reforestation Projects, the Project Area must be on land that has had less than 10 percent tree canopy cover for a minimum of ten years, or that have been subject to a Significant Disturbance that resulted in at least 20 percent of the carbon stocks being emitted.

For Avoided Conversion Projects, the Project Area is defined through the required appraisal process. The Project Area must be determined following the boundary definitions in Table 4.1 based on the type of anticipated conversion.

Table 4.1. Project Area Definition for Avoided Conversion Projects

Conversion Type	Project Area Definition
Residential	The boundary of the parcel or parcels that have been appraised as having a 'higher and better use' in residential development.
Agricultural Conversion or Mining	The boundary of the parcel or parcels that have been appraised as having a 'higher and better use' in agricultural production or mining.
Golf Course	The boundary of the parcel or parcels that have been appraised as having a 'higher and better use' as a golf course. This is to include forested areas within 200' of fairways, greens, and buildings.
Commercial Buildings	The boundary of the parcel or parcels that have been appraised as having a 'higher and better use' in commercial buildings. This is to include forested areas with 200' of suitable building sites.

5 Offset Project Boundary

The Offset Project Boundary defines all the GHG emission sources, sinks, and reservoirs (SSR's) that must be accounted for in quantifying a Forest Project's GHG reductions and removal enhancements (Section 6). The Offset Project Boundary encompasses all the GHG emission SSR's that may be significantly affected by Forest Project activities, such as forest carbon stocks and harvested wood products. For accounting purposes, the sources, sinks, and reservoirs included in the Offset Project Boundary are organized according to whether they are predominantly associated with a Forest Project's "Primary Effect" (i.e. the Forest Project's intended changes in carbon stocks, GHG emissions, or GHG removals) or its "Secondary Effects" (i.e. unintended changes in carbon stocks, GHG emissions, or GHG removals caused by the Forest Project). Secondary effects may include increases in mobile combustion CO_2 emissions associated with site preparation, as well as increased CO_2 emissions caused by the shifting of harvesting activities from the Project Area to other forestlands (referred to as "Leakage"). Projects are required to account for Secondary Effects following the methods described in Section 6.

The following tables provide a comprehensive list of the SSRs that may be affected by a Forest Project, and indicate which SSRs must be included in the Offset Project Boundary for each type of Forest Project. If a SSR is designated as a "reservoir/pool," this means that GHG reductions and removals are accounted for by quantifying changes in carbon stock levels. For SSRs designated as sources or sinks, GHG reductions and removals are accounted for by quantifying changes in GHG emission or removal rates, as described in the tables.

5.1 Reforestation Projects

Table 5.1. Offset Project Boundary – Reforestation Projects

SSR	Description	Type	Gas	Included or Excluded?	Quantification Method
Primary Effect Sources, Sinks, and Reservoirs					
RF-1	Standing live carbon (carbon in all portions of living trees)	Reservoir / Pool	CO_2	Included	**Baseline:** Modeled based on initial field inventory measurements **Project:** Measured by field measurements and updating forest carbon inventory
RF-2	Shrubs and herbaceous understory carbon	Reservoir / Pool	CO_2	Included	**Baseline:** Modeled based on initial field inventory measurements **Project:** Measured by updating forest carbon inventory
RF-3	Standing dead carbon (carbon in all portions of dead, standing trees)	Reservoir / Pool	CO_2	Included	**Baseline:** Modeled based on initial field inventory measurements **Project:** Measured by updating forest carbon inventory
RF-4	Lying dead wood carbon	Reservoir / Pool	CO_2	Excluded	**Baseline:** N/A **Project:** N/A
RF-5	Litter and duff carbon (carbon in dead plant material)	Reservoir / Pool	CO_2	Excluded	**Baseline:** N/A **Project:** N/A

SSR	Description	Type	Gas	Included or Excluded?	Quantification Method
RF-6	Soil carbon	Reservoir / Pool	CO_2	*Included/excluded: Soil carbon must be included in the Offset Project Boundary if any of the following occur: ▪ Site preparation activities involve deep ripping, furrowing, or plowing where soil disturbance exceeds 25 percent of the Project Area, or ▪ Mechanical site preparation activities are not conducted on contours.	**Baseline:** Modeled based on initial field inventory measurements **Project:** Measured by updating forest carbon inventory
RF-7	Carbon in in-use forest products	Reservoir / Pool	CO_2	Included	**Baseline:** Estimated from modeled harvesting volumes **Project:** Estimated from measured harvesting volumes
RF-8	Forest product carbon in landfills	Reservoir / Pool	CO_2	Excluded when project harvesting exceeds baseline Included when project harvesting is below baseline	**Baseline:** Estimated from modeled harvesting volumes **Project:** Estimated from measured harvesting volumes
Secondary Effect Sources, Sinks, and Reservoirs					
RF-9	Biological emissions from site preparation activities	Source	CO_2	*Included: Biological emissions from site preparation are not quantified separately, but rather are captured by measuring changes in included carbon reservoirs	**Baseline:** N/A **Project:** Quantified based on measured carbon stock changes in included reservoirs (SSRs #RF-2 and #RF-6)
RF-10	Mobile combustion emissions from site preparation activities	Source	CO_2	Included	**Baseline:** N/A **Project:** Estimated using default emission factors
			CH_4	Excluded	**Baseline:** N/A **Project:** N/A
			N_2O	Excluded	**Baseline:** N/A **Project:** N/A
RF-11	Mobile combustion emissions from ongoing project operation & maintenance	Source	CO_2	Excluded	**Baseline:** N/A **Project:** N/A
			CH_4	Excluded	**Baseline:** N/A **Project:** N/A
			N_2O	Excluded	**Baseline:** N/A **Project:** N/A
RF-12	Stationary combustion emissions from ongoing project operation & maintenance	Source	CO_2	Excluded	**Baseline:** N/A **Project:** N/A
			CH_4	Excluded	**Baseline:** N/A **Project:** N/A

SSR	Description	Type	Gas	Included or Excluded?	Quantification Method
			N_2O	Excluded	**Baseline:** N/A **Project:** N/A
RF-13	Biological emissions from clearing of forestland outside the Project Area	Source	CO_2	Included	**Baseline:** N/A **Project:** Estimated using default land-use conversion factors for non-project land
RF-14	Biological emissions/ removals from changes in harvesting on forestland outside the Project Area	Source / Sink	CO_2	Excluded	**Baseline:** N/A **Project:** N/A
RF-15	Combustion emissions from production, transportation, and disposal of forest products	Source	CO_2	Excluded	**Baseline:** N/A **Project:** N/A
			CH_4	Excluded	**Baseline:** N/A **Project:** N/A
			N_2O	Excluded	**Baseline:** N/A **Project:** N/A
RF-16	Combustion emissions from production, transportation, and disposal of alternative materials to forest products	Source	CO_2	Excluded	**Baseline:** N/A **Project:** N/A
			CH_4	Excluded	**Baseline:** N/A **Project:** N/A
			N_2O	Excluded	**Baseline:** N/A **Project:** N/A
RF-17	Biological emissions from decomposition of forest products	Source	CO_2	Included	**Baseline:** Quantified as a component of calculating carbon stored for 100 years in wood products (SSR #RF-7) and landfills (SSR #RF-8) **Project:** Quantified as a component of calculating carbon stored for 100 years in wood products (SSR #RF-7) and landfills (SSR #RF-8)
			CH_4	Excluded	**Baseline:** N/A **Project:** N/A
			N_2O	Excluded	**Baseline:** N/A **Project:** N/A

5.2 Improved Forest Management Projects

Table 5.2. Offset Project Boundary – Improved Forest Management Projects

SSR	Description	Type	Gas	Included or Excluded?	Quantification Method
Primary Effect Sources, Sinks, and Reservoirs					
IFM-1	Standing live carbon (carbon in all portions of living trees)	Reservoir / Pool	CO_2	Included	**Baseline:** Modeled based on initial field inventory measurements **Project:** Measured by field measurements and updating forest carbon inventory
IFM-2	Shrubs and herbaceous understory carbon	Reservoir / Pool	CO_2	Excluded	**Baseline:** N/A **Project:** N/A
IFM-3	Standing dead carbon (carbon in all portions of dead, standing trees)	Reservoir / Pool	CO_2	Included	**Baseline:** Modeled based on initial field inventory measurements **Project:** Measured by updating forest carbon inventory
IFM-4	Lying dead wood carbon	Reservoir / Pool	CO_2	Excluded	**Baseline:** N/A **Project:** N/A
IFM-5	Litter and duff carbon (carbon in dead plant material)	Reservoir / Pool	CO_2	Excluded	**Baseline:** Modeled based on initial field inventory measurements **Project:** Measured by updating forest carbon inventory
IFM-6	Soil carbon	Reservoir / Pool	CO_2	*Included/ Excluded Soil carbon must be included in the Offset Project Boundary, if any of the following activities occur: ▪ Site preparation activities involve deep ripping, furrowing, or plowing where soil disturbance exceeds 25 percent of the Project Area, or ▪ Mechanical site preparation activities are not conducted on contours.	**Baseline:** Modeled based on initial field inventory measurements **Project:** Measured by updating forest carbon inventory
IFM-7	Carbon in in-use forest products	Reservoir / Pool	CO_2	Included	**Baseline:** Estimated from modeled harvesting volumes **Project:** Estimated from measured harvesting volumes
IFM-8	Forest product carbon in landfills	Reservoir / Pool	CO_2	Excluded when project harvesting exceeds baseline Included when project harvesting is below baseline	**Baseline:** Estimated from modeled harvesting volumes **Project:** Estimated from measured harvesting volumes
Secondary Effect Sources, Sinks, and Reservoirs					
IFM-9	Biological emissions from site preparation activities	Source	CO_2	*Included Biological emissions from site preparation are not quantified separately, but rather are captured by measuring	**Baseline:** N/A **Project:** Quantified based on measured carbon stock changes in included reservoirs (SSR #IFM-6, where applicable)

SSR	Description	Type	Gas	Included or Excluded?	Quantification Method
				changes in included carbon reservoirs	
IFM-10	Mobile combustion emissions from site preparation activities	Source	CO_2	Excluded	**Baseline:** N/A **Project:** N/A
			CH_4	Excluded	**Baseline:** N/A **Project:** N/A
			N_2O	Excluded	**Baseline:** N/A **Project:** N/A
IFM-11	Mobile combustion emissions from ongoing project operation & maintenance	Source	CO_2	Excluded	**Baseline:** N/A **Project:** N/A
			CH_4	Excluded	**Baseline:** N/A **Project:** N/A
			N_2O	Excluded	**Baseline:** N/A **Project:** N/A
IFM-12	Stationary combustion emissions from ongoing project operation & maintenance	Source	CO_2	Excluded	**Baseline:** N/A **Project:** N/A
			CH_4	Excluded	**Baseline:** N/A **Project:** N/A
			N_2O	Excluded	**Baseline:** N/A **Project:** N/A
IFM-13	Biological emissions from clearing of forestland outside the Project Area	Source	CO_2	Excluded	**Baseline:** N/A **Project:** N/A
IFM-14	Biological emissions/ removals from changes in harvesting on forestland outside the Project Area	Source / Sink	CO_2	Included / Excluded	**Baseline:** N/A **Project:** Estimated using a default 20% "leakage" factor applied to the difference in harvest volume relative to baseline
IFM-15	Combustion emissions from production, transportation, and disposal of forest products	Source	CO_2	Excluded	**Baseline:** N/A **Project:** N/A
			CH_4	Excluded	**Baseline:** N/A **Project:** N/A
			N_2O	Excluded	**Baseline:** N/A **Project:** N/A
IFM-16	Combustion emissions from	Source	CO_2	Excluded	**Baseline:** N/A

SSR	Description	Type	Gas	Included or Excluded?	Quantification Method
	production, transportation, and disposal of alternative materials to forest products				**Project:** N/A
			CH_4	Excluded	**Baseline:** N/A **Project:** N/A
			N_2O	Excluded	**Baseline:** N/A **Project:** N/A
IFM-17	Biological emissions from decomposition of forest products	Source	CO_2	*Included	**Baseline:** Quantified as a component of calculating carbon stored for 100 years in wood products (SSR #IFM-7) and landfills (SSR #IFM-8) **Project:** Quantified as a component of calculating carbon stored for 100 years in wood products (SSR #IFM-7) and landfills (SSR #IFM-8)
			CH_4	Excluded	**Baseline:** N/A **Project:** N/A
			N_2O	Excluded	**Baseline:** N/A **Project:** N/A

5.3 Avoided Conversion Projects

Table 5.3. Offset Project Boundary – Avoided Conversion Projects

SSR	Description	Type	Gas	Included or Excluded?	Quantification Method
Primary Effect Sources, Sinks, and Reservoirs					
AC-1	Standing live carbon (carbon in all portions of living trees)	Reservoir / Pool	CO_2	Included	**Baseline:** Modeled based on initial field inventory measurements and expected land-use conversion rates **Project:** Measured by field measurements and updating forest carbon inventory
AC-2	Shrubs and herbaceous understory carbon	Reservoir / Pool	CO_2	Excluded	**Baseline:** N/A **Project:** N/A
AC-3	Standing dead carbon (carbon in all portions of dead, standing trees)	Reservoir / Pool	CO_2	Included	**Baseline:** Modeled based on initial field inventory measurements and expected land-use conversion rates **Project:** Measured by updating forest carbon inventory
AC-4	Lying dead wood carbon	Reservoir / Pool	CO_2	Excluded	**Baseline:** N/A **Project:** N/A
AC-5	Litter and duff carbon (carbon in dead plant material)	Reservoir / Pool	CO_2	Excluded	**Baseline:** N/A **Project:** N/A
AC-6	Soil carbon	Reservoir	CO_2	*Included/ Excluded	**Baseline:** Modeled based on initial field inventory

SSR	Description	Type	Gas	Included or Excluded?	Quantification Method
		/ Pool		Soil carbon must be included in the Offset Project Boundary, if any of the following activities occur: ▪ Site preparation activities involve deep ripping, furrowing, or plowing where soil disturbance exceeds 25 percent of the Project Area, or Mechanical site preparation activities are not conducted on contours.	measurements and expected land-use conversion rates **Project:** Measured by updating forest carbon inventory
AC-7	Carbon in in-use forest products	Reservoir / Pool	CO_2	Included	**Baseline:** Estimated from modeled harvesting volumes **Project:** Estimated from measured harvesting volumes
AC-8	Forest product carbon in landfills	Reservoir / Pool	CO_2	Excluded when project harvesting exceeds baseline Included when project harvesting is below baseline	**Baseline:** Estimated from modeled harvesting volumes **Project:** Estimated from measured harvesting volumes
Secondary Effect Sources, Sinks, and Reservoirs					
AC-9	Biological emissions from site preparation activities	Source	CO_2	*Included Biological emissions from site preparation are not quantified separately, but rather are captured by measuring changes in included carbon reservoirs	**Baseline:** N/A **Project:** Quantified based on measured carbon stock changes in included reservoirs (SSR #AC-6, where applicable)
AC-10	Mobile combustion emissions from site preparation activities	Source	CO_2	Excluded	**Baseline:** N/A **Project:** N/A
			CH_4	Excluded	**Baseline:** N/A **Project:** N/A
			N_2O	Excluded	**Baseline:** N/A **Project:** N/A
AC-11	Mobile combustion emissions from ongoing project operation & maintenance	Source	CO_2	Excluded	**Baseline:** N/A **Project:** N/A
			CH_4	Excluded	**Baseline:** N/A **Project:** N/A
			N_2O	Excluded	**Baseline:** N/A **Project:** N/A
AC-12	Stationary combustion emissions from ongoing project operation & maintenance	Source	CO_2	Excluded	**Baseline:** N/A **Project:** N/A
			CH_4	Excluded	**Baseline:** N/A **Project:** N/A
			N_2O	Excluded	**Baseline:** N/A

SSR	Description	Type	Gas	Included or Excluded?	Quantification Method
					Project: N/A
AC-13	Biological emissions from clearing of forestland outside the Project Area	Source	CO_2	Included	**Baseline:** N/A **Project:** Estimated using default forestland conversion factors
AC-14	Biological emissions/ removals from changes in harvesting on forestland outside the Project Area	Source / Sink	CO_2	Excluded	**Baseline:** N/A **Project:** N/A
AC-15	Combustion emissions from production, transportation, and disposal of forest products	Source	CO_2	Excluded	**Baseline:** N/A **Project:** N/A
			CH_4	Excluded	**Baseline:** N/A **Project:** N/A
			N_2O	Excluded	**Baseline:** N/A **Project:** N/A
AC-16	Combustion emissions from production, transportation, and disposal of alternative materials to forest products	Source	CO_2	Excluded	**Baseline:** N/A **Project:** N/A
			CH_4	Excluded	**Baseline:** N/A **Project:** N/A
			N_2O	Excluded	**Baseline:** N/A **Project:** N/A
AC-17	Biological emissions from decomposition of forest products	Source	CO_2	Included	**Baseline:** Quantified as a component of calculating carbon stored for 100 years in wood products (SSR #AC-7) and landfills (SSR #AC-8) **Project:** Quantified as a component of calculating carbon stored for 100 years in wood products (SSR #AC-7) and landfills (SSR #AC-8)
			CH_4	Excluded	**Baseline:** N/A **Project:** N/A
			N_2O	Excluded	**Baseline:** N/A **Project:** N/A Decomposition of forest is not expected to be a significant source of N_2O emissions.

6 Quantifying Net GHG Reductions and Removals

This section provides requirements and methods for quantifying a Forest Project's net GHG reductions and removals.

Quantification Methodology:
For each type of Forest Project, quantification proceeds in seven steps:

1. **Estimating baseline onsite carbon stocks.** The baseline is an estimate of what would have occurred in the absence of a Forest Project. To establish baseline onsite carbon stocks, the carbon stock changes in each of the Forest Project's required onsite carbon pools (identified in Sections 5.1 to 5.3) must be modeled over 100 years. Modeling must be based on inventoried carbon stocks at the time of the Forest Project's commencement (or when first inventoried as is allowed for Reforestation Projects), following the applicable requirements in this section. Onsite carbon stocks are inventoried following the requirements in Appendix A; modeling of onsite carbon stocks over time must be conducted following the requirements in this section and the requirements and methods in Appendix B. Baseline onsite carbon stocks are estimated over 100 years at the time of the project's initiation.
2. **Estimating baseline carbon in harvested wood products.** In conjunction with modeling baseline onsite carbon stocks, a forecast of any harvesting that would have occurred in the baseline must be developed and converted to an average annual harvesting volume. From this, the amount of carbon that would have been transferred each year (on average) to long-term storage in wood products can be determined. Baseline harvesting is forecasted following the requirements in this section and carbon stored in wood products must be calculated following the requirements and methods in Appendix C.
3. **Determining actual onsite carbon stocks.** Each year, the Forest Project's actual onsite carbon stocks must be determined. This must be done by updating the Forest Project's forest carbon inventory for the current year, following the requirements and methods in this section and in Appendices A and B. The estimate of actual onsite carbon stocks must be adjusted by an appropriate confidence deduction, as described in Appendix A, Section A.4.
4. **Determining actual carbon in harvested wood products.** Each year, any harvesting in the Project Area must be reported and from this, the amount of carbon transferred to long-term storage in wood products must be calculated following the requirements and methods in Appendix C.
5. **Calculating the project's Primary Effect.** Each year, the actual change in GHG emissions or removals associated with the Forest Project's intended ("Primary") effect must be quantified, as defined in Section 5. For any given year, the Primary Effect is calculated by:
    a. Taking the difference between actual onsite carbon stocks for the current year and actual onsite carbon stocks for the prior year
    b. Subtracting from (a) the difference between baseline onsite carbon stocks for the current year and baseline onsite carbon stocks for the prior year
    c. Adding to (b) the calculated difference between actual and baseline carbon in harvested wood products for the current year (see Equation 6.1.)

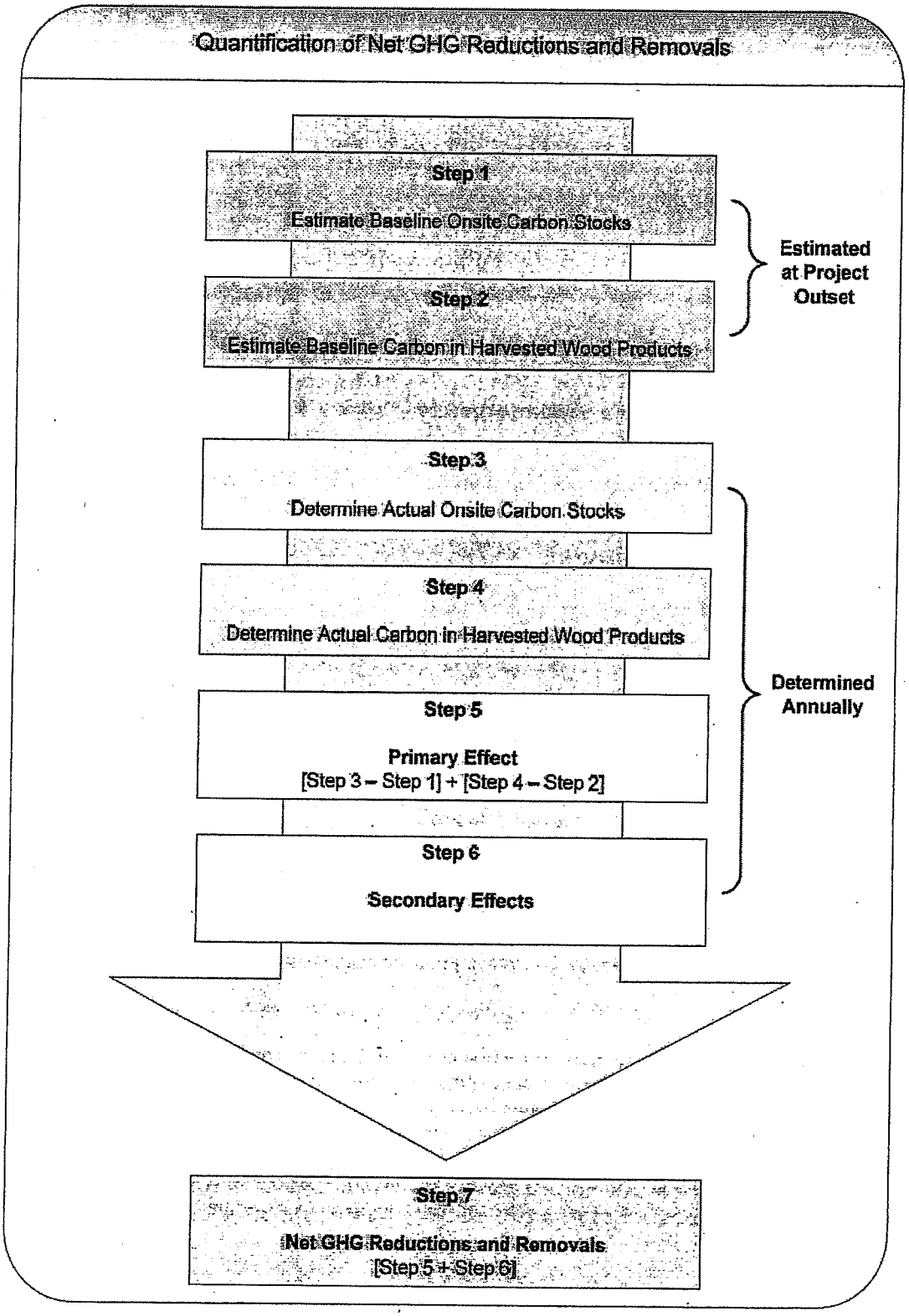
6. **Quantifying the project's Secondary Effects.** Each year, the actual change in GHG emissions or removals associated with the Forest Project's unintended ("Secondary")

effects must be quantified as defined in Section 5. Requirements and methods for quantifying Secondary Effects are provided below for each type of Forest Project. Secondary Effects will almost always be negative (i.e. they will reflect an increase in GHG emissions caused by the project).

7. **Calculating total net GHG reductions and removals.** For each year, total net GHG reductions and removals are calculated by summing a Forest Project's Primary and Secondary Effects. If the result is positive, then the Forest Project has generated GHG reductions and/or removals in the current year. If the result is negative, this indicates a reversal has occurred except as specified below (see Section 7).

Requirements for how to perform quantification steps 1 to 4 for each Forest Project type are presented in the remainder of this section. The required formula for quantifying annual net GHG reductions and removals is presented in Equation 6.1. Net GHG reductions and removals must be quantified and reported in units of carbon dioxide-equivalent (CO_2e) metric tons.

A reversal occurs only if: (1) total net GHG reductions and removals for the year are negative; and (2) Offset Credits have previously been issued to the Forest Project. If calculated GHG reductions and removals are negative and no Offset Credits have been issued to the project since its commencement date then the result should be treated as a "negative carryover" to GHG reduction calculations in subsequent years (variable N_{y-1} in Equation 6.1). This may happen, for example, because the confidence deduction applied to actual onsite carbon stocks can result in actual values being less than baseline values in a Forest Project's initial years.


Quantification of Net GHG Reductions and Removals
Step 1
Estimate Baseline Onsite Carbon Stocks
Step 2
Estimate Baseline Carbon in Harvested Wood Products
Estimated at Project Outset
Step 3
Determine Actual Onsite Carbon Stocks
Step 4
Determine Actual Carbon in Harvested Wood Products
Step 5
Primary Effect
[Step 3 – Step 1] + [Step 4 – Step 2]
Step 6
Secondary Effects
Determined Annually
Step 7
Net GHG Reductions and Removals
[Step 5 + Step 6]

Quantification Methodology

Equation 6.1.

$$QR_y = [(\Delta AC_{onsite} - \Delta BC_{onsite}) + (AC_{wp,\,y} - BC_{wp,\,y}) * 80\% + SE_y] * (1 - ACD) + N_{y-1}$$

Where,

QR_y = Quantified GHG reductions and removals for year y

ΔAC_{onsite} = $(AC_{onsite,\,y})(1 - CD_y) - (AC_{onsite,\,y-1})(1 - CD_{y-1})$

Where,

$AC_{onsite,\,y}$ = Actual onsite carbon (CO_2e) as inventoried for year y

$AC_{onsite,\,y-1}$ = Actual onsite carbon (CO_2e) as inventoried for year y-1 (if y is the first year of the project, then the value for $AC_{onsite,\,y-1}$ will be zero)

CD_y = Appropriate confidence deduction for year y, as determined in Appendix A, Section A.4.

CD_{y-1} = Appropriate confidence deduction for year y-1, as determined in Appendix A, Section A.4.

ΔBC_{onsite} = $BC_{onsite,\,y} - BC_{onsite,\,y-1}$

Where,

$BC_{onsite,\,y}$ = Baseline onsite carbon (CO_2e) as estimated for year y

$BC_{onsite,\,y-1}$ = Baseline onsite carbon (CO_2e) as estimated for year y-1 (if y is the first year of the project, then the value for $BC_{onsite,\,y-1}$ will be zero)[5]

$AC_{wp,\,y}$ = Actual carbon in wood products produced in year y that is projected to remain stored for at least 100 years (i.e. $WP_{total,\,y}$ derived for actual harvest volumes following the requirements and methods in Appendix C)

$BC_{wp,y}$ = Averaged annual baseline carbon in wood products that would have remained stored for at least 100 years (i.e. $WP_{total,\,y}$ derived for baseline harvest volumes following the requirements and methods in Appendix C)

SE_y = Secondary Effect GHG emissions caused by the project activity in year y

ACD = Avoided Conversion Project discount factor, determined in Section 6.3.1

N_{y-1} = Any negative carryover from the prior year (occurs when total quantified GHG reductions are negative prior to the issuance of any CRTs for the project)

Note: The net change in carbon in harvested wood products, $(AC_{wp,\,y} - BC_{wp,\,y})$, is multiplied by 80 percent in Equation 6.1 to reflect market responses to changes in wood product production. The general assumption in this protocol is that for every ton of reduced harvesting caused by a Forest Project, the market will compensate with an increase in harvesting of 0.2 tons on other lands (see Section 6.2.6).

[5] For Improved Forest Management projects, where baseline onsite carbon stocks are averaged across all years, the value for ΔBC_{onsite} will be zero in all years except the first year of the project.

6.1 Reforestation Projects

6.1.1 Estimating Baseline Onsite Carbon Stocks

Quantification Methodology

To estimate baseline carbon stocks for a Reforestation Project:

1. Provide a qualitative characterization of the likely vegetative conditions and activities that would have occurred without the project, taking into consideration any laws, statutes, regulations, or other legal mandates that would encourage or require reforestation on the Project Area. The qualitative assessment shall include an assessment of the commercial value of trees within the Project Area over the next 30 years. The qualitative assessment must be used as the basis for modeling baseline carbon stocks (Step 3).
2. Inventory the carbon stocks in each of the project's required carbon pools, following the requirements in Appendix A of this protocol.[6] For carbon pools that will be affected by site preparation, the inventory must be conducted prior to any site preparation activities. For those carbon pools that are affected by site preparation, provide an estimate of initial carbon stocks using one of the following alternatives:
    - Measuring carbon stocks using 20 sample plots located in the portion of the Project Area containing the greatest amount of biomass in the pool that will be affected.
    - Stratifying (classifying) the Project Area into similar densities and measuring stocks within the affected carbon pools using 20 sample plots per density class.
    - Measuring the affected carbon stocks based on a grid system across the Project Area.

For other carbon stocks, the inventory may be deferred, as described below.

3. Once a full inventory is obtained, perform a computer simulation that models the carbon stocks for 100 years following the forest project's commencement date, based on the qualitative characterization of what would have occurred without the project. The modeling must follow the requirements and methods for modeling contained in Appendix B, Section B.3, incorporating any conditions and constraints specified in the qualitative characterization of the baseline (Step 1, above). The computer simulation must model the expected growth in carbon stocks associated with pre-existing trees in the Project Area (i.e. those not planted as part of the Forest Project).

Deferral of Initial Inventory for Carbon Stocks Not Affected by Site Preparation

The inventory of carbon stocks that are not affected by site preparation may be deferred until a Reforestation Project's second verification. At the time of the second verification, an estimated inventory of the all required carbon stocks at the time of the Forest Project's commencement date must prepared by:

1. Assuming standing dead carbon stocks at the time of the Forest Projects' commencement date were equal to the standing dead carbon stocks measured and verified at the second verification.
2. Using an approved growth model or a stand table projection methodology, as described in Appendix B, Section B.1, to derive an estimate of standing live carbon stocks in pre-existing trees (i.e. those not planted as part of the Forest Project) at the time of the

[6] Initial carbon stocks could be zero if the Project Area has no quantifiable forest cover or required carbon pools.

Forest Project's commencement date. The approved growth model or stand table projection used for the estimate must produce a result within 5 percent of current inventory data for pre-existing trees.

If the inventory of these carbon pools is deferred, the timing of the second verification is at the discretion of the Offset Project Operator or Authorized Project Designee (but must occur within 12 years of the initial verification). Reforestation Projects for which an initial inventory is deferred are not eligible to receive Offset Credits until after the second verification.

6.1.2 Estimating Baseline Carbon in Harvested Wood Products

Quantification Methodology

If harvesting of the pre-existing trees would be expected to occur in the baseline, the following steps must be performed:

1. Use a model (see Appendix B) to determine the *average* amount of carbon in standing live carbon stocks (prior to delivery to a mill) that would have been harvested in each year of the baseline over 100 years. The result will be a uniform estimate of harvested carbon in each year of the baseline. This estimate is determined at project commencement using the same biomass equations used to calculate biomass in live trees, and will not change over the course of the project crediting period.
2. On an annual basis, determine the amount of harvested carbon that would have remained stored in wood products, averaged over 100 years, following the requirements and methods in Appendix C.

6.1.3 Determining Actual Onsite Carbon Stocks

Quantification Methodology

Actual carbon stocks for Reforestation Projects must be determined by updating the Project Area's forest carbon inventory. This is done by:

1. Incorporating any new forest inventory data obtained during the previous year into the inventory estimate. Any plots sampled during the previous year must be incorporated into the inventory estimate.
2. Using an approved model to "grow" (project forward) prior-year data from existing forest inventory plots to the current reporting year. Approved growth models and requirements and methods for projecting forest inventory plot data using models is provided in Appendix B.
3. Updating the forest inventory estimate for harvests and/or disturbances that have occurred during the previous year.
4. Applying an appropriate confidence deduction for the inventory based on its statistical uncertainty, following the requirements and methods in Appendix A, Section A.4.

6.1.4 Determining Actual Carbon in Harvested Wood Products

Quantification Methodology

Perform the following steps to determine actual carbon in harvested wood products:

1. Determine the actual amount of carbon in standing live carbon stocks (prior to delivery to a mill) harvested in the current year (based on harvest volumes determined in Section 6.1.3).
2. Determine the amount of actual harvested carbon that will remain stored in wood products, averaged over 100 years, following the requirements and methods in Appendix C.

6.1.5 Quantifying Secondary Effects

Quantification Methodology

For Reforestation Projects, significant Secondary Effects can arise from two sources:

1. One-time combustion emissions associated with machinery use in site preparation; and
2. The shifting of cropland or grazing activities to forestland outside the Project Area (which may be both a market and/or physical response to the project activity), which is accounted for over the Project Life.

To quantify combustion emissions associated with site preparation, use the appropriate standard emission factor from Table 6.1 corresponding to the level of brush cover on the Project Area, multiplied by the number of acres in the Project Area (Equation 6.2).

Mobile combustion emissions must be added to Secondary Effect emissions (SE_y in Equation 6.1) in the first year of a project. If this results in a negative amount for total net quantified GHG reductions and removals in year one (QR_1), the negative amount must be carried over into future years (N_{y-1} in Equation 6.1) until sufficient GHG reductions and removals are accrued to achieve a positive balance. Negative GHG reductions and removals due to site preparation emissions are *not* considered a reversal (Section 7.1).

Equation 6.2. Combustion Emissions Associated with Site Preparation

$$\mathbf{MC_y = (-1) \times (EF_{mc} \times PA)}$$

Where,

MC_y = Secondary Effect CO_2e emissions due to mobile combustion from site preparation

EF_{mc} = Mobile combustion emission factor from Table 6.1

PA = The size of the Project Area, in acres

Table 6.1. Mobile Combustion Emissions for Reforestation Projects

SITE PREP - REFORESTATION PROJECTS Emissions Associated with Mobile Combustion		
Average Metric Tons CO_2e Per Acre		
Light	Medium	Heavy
25% Brush Cover	50% Dense Brush Cover	> 50% Brush Cover, stump removal
0.090	**0.202**	**0.429**

To quantify emissions from the shifting of cropland and grazing activities each year, determine the appropriate "leakage" risk percentage for the project following the decision tree in Figure 6.3. The leakage risk percentage is only determined once, at project commencement. Each year, this percentage must be applied to the net increase in onsite carbon stocks to determine the annual Secondary Effects due to shifting of cropland or grazing activities (Equation 6.3).

Equation 6.3. Emissions from Shifting Cropland and Grazing Activities

$\mathbf{AS_y = (-1) \times L \times (\Delta\ AC_{onsite} - \Delta\ BC_{onsite})}$

Where,

AS_y = Secondary Effect CO_2e emissions due to shifting of cropland or grazing activities

L = Leakage risk percentage, as determined from Figure 6.3

$\Delta\ AC_{onsite}$ = Annual difference in actual onsite carbon (CO_2e) as defined in Equation 6.1.

$\Delta\ BC_{onsite}$ = Annual difference in baseline onsite carbon (CO_2e) as defined in Equation 6.1.

Total Secondary Effect emissions for Reforestation Projects are calculated as follows (Equation 6.4). The value for Secondary Effect emissions will always be negative or zero.

Equation 6.4. Total Secondary Effect Emissions

$\mathbf{SE_y = (AS_y + MC_y)}$ *or* **0**, whichever is lower

Where,

SE_y = Secondary Effect GHG emissions caused by the project activity in year y (Equation 6.1)

AS_y = Secondary Effect CO_2e emissions due to shifting of cropland or grazing activities

MC_y = Secondary Effect CO_2e emissions due to mobile combustion from site preparation*

*only occurs in year 1.

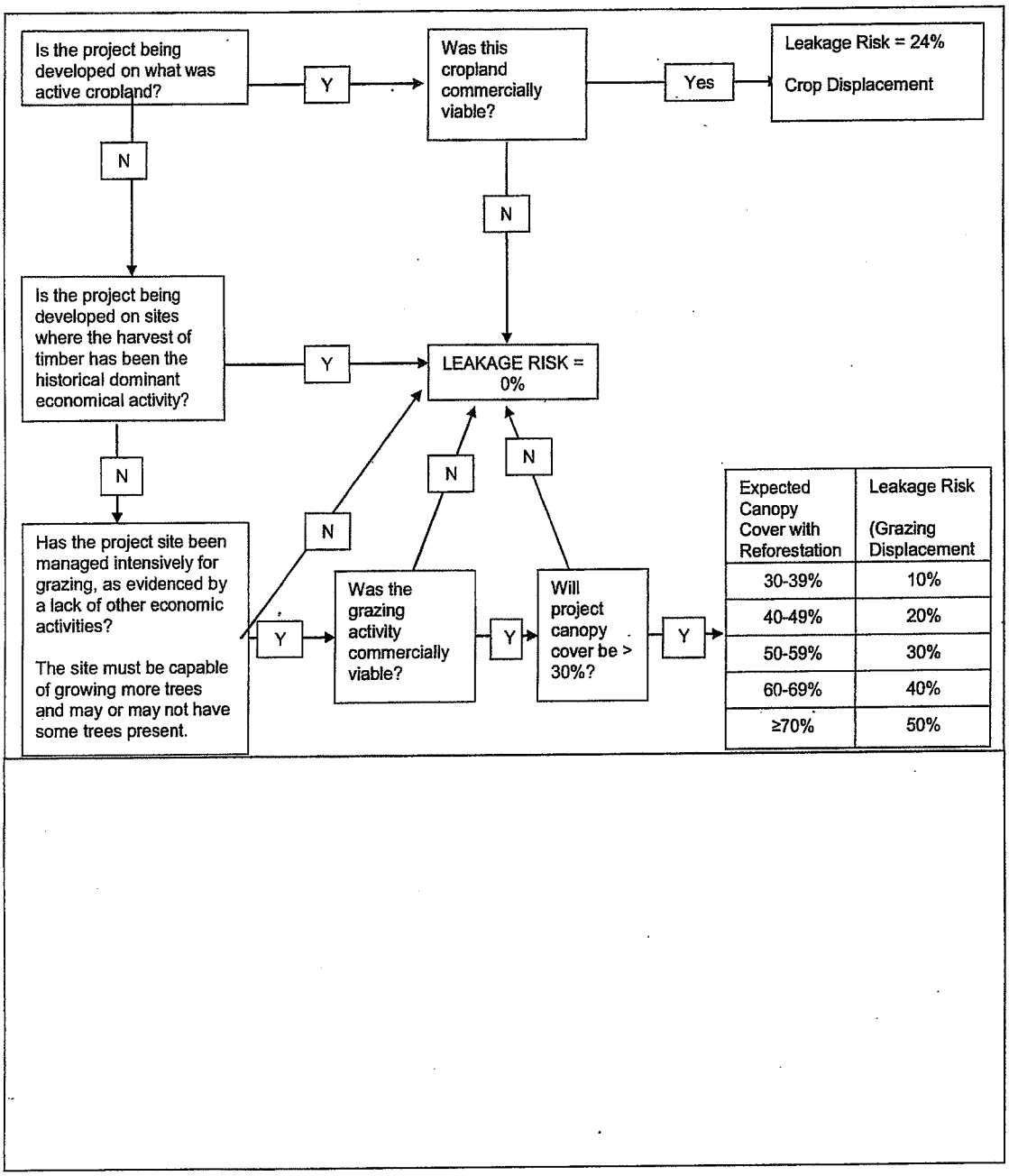


Figure 6.3. Activity Shifting ("Leakage") Risk Assessment for Reforestation Projects

6.2 Improved Forest Management Projects

Improved Forest Management Projects that take place on private land – or on land that is transferred to public ownership at the time the project is initiated – must estimate baseline onsite carbon stocks following the requirements and procedures in Section 6.2.1. Improved Forest Management Projects that take place on land that was publicly owned prior to the offset project commencement date must estimate baseline onsite carbon stocks following the requirements and procedures in Section 6.2.2. Requirements for determining baseline carbon in harvested wood products, determining actual onsite carbon stocks, determining actual carbon in harvested wood products, and quantifying Secondary Effects are the same for all Improved Forest Management Projects.

6.2.1 Estimating Baseline Onsite Carbon Stocks – Private Lands

Quantification Methodology

The baseline approach for Improved Forest Management Projects on private lands applies a standardized set of assumptions to project-specific conditions. A key assumption is that baseline carbon stocks will depend on how a project's initial standing live carbon stocks compare to "Common Practice," defined as the average standing live carbon stocks on similar lands within the project's Assessment Area. In addition, baseline carbon stocks must be adjusted to reflect management practice on the Forest Owner's other landholdings in instances where Project Area carbon stocks are more than 20 percent below the carbon stocks on land within the same logical management unit. Finally, the baseline must be modeled to reflect all legal and economic constraints affecting the Project Area.

The following steps must be followed to estimate baseline carbon stocks:

1. Determine the Common Practice level of above-ground standing live carbon stocks applicable to the Project Area.
2. Determine if the Project Area's initial above-ground standing live carbon stocks are above or below Common Practice.
3. Estimate baseline above-ground standing live carbon stocks, taking into account financial and legal constraints on harvesting in the Project Area, as well as the minimum baseline level applicable to the Project Area, as defined in the requirements for Step 3, below. The minimum baseline level will depend on whether initial above-ground standing live carbon stocks are above or below Common Practice.
4. Determine the baseline carbon stocks over 100 years for all required carbon pools in the Project Area.

For all calculations in this section, all values for "carbon stocks" should be expressed in metric tons of CO_2-equivalent.

Step 1 – Determine the Common Practice Carbon Stocks for the Project's Assessment Area

As defined in this protocol, Common Practice refers to the average stocks of above-ground standing live carbon associated with the Assessment Area(s) covered by the Project Area. Common Practice is used as a reference point for baseline estimation. To determine a value for Common Practice, see Appendix F and the data available in the Forest Offset Protocol Resources section of ARB's website.

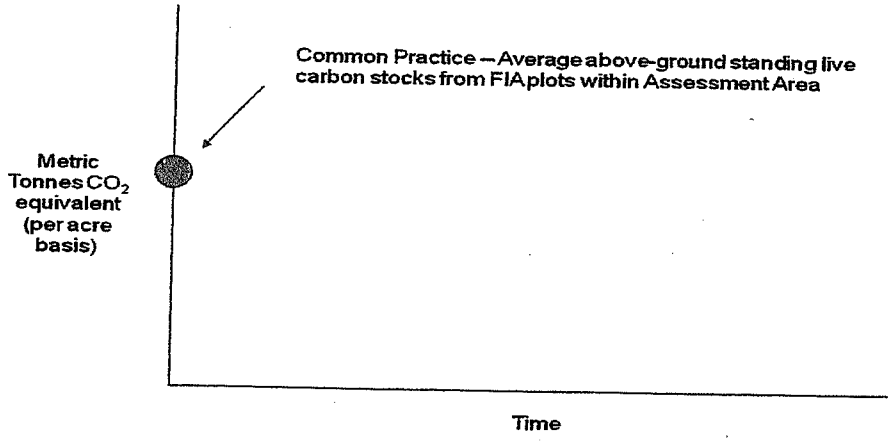


Figure 6.4. Common Practice as a Reference Point for Baseline Estimation

Step 2 – Determine if Initial Above-Ground Standing Live Carbon Stocks Are Above or Below Common Practice

To determine if initial above-ground standing live carbon stocks are above or below Common Practice, perform the following steps:

1. From the initial forest carbon inventory for the Project Area (conducted following the requirements in Appendix A), identify the metric tons of carbon contained in the *above-ground portion* of standing live carbon stocks.
2. Divide this amount by the number of acres in the Project Area.
3. Compare the result with the Common Practice value identified in Step 1.

Step 3 – Determine Baseline Above-Ground Standing Live Carbon Stocks

The baseline above-ground standing live carbon stocks must be determined by: (1) Modeling above-ground standing live carbon stocks through a series of growth and harvesting scenarios over 100 years; and (2) averaging the model results over the 100-year timeframe, so that the baseline is expressed as a single (average) value for above-ground standing live carbon stocks per acre in every year. The modeling must be performed following the requirements and methods in Appendix B and must meet the following conditions:

1. Growth and harvesting scenarios must reflect all legal constraints, following the requirements in Section 6.2.1.2.
2. Growth and harvesting scenarios must reflect any financial constraints, following the requirements in Section 6.2.1.3.
3. The averaged model results, expressed as above-ground standing live carbon stocks per acre, must not fall below a minimum baseline level (MBL). If initial above-ground standing live carbon stocks are above Common Practice, the MBL must be determined using the formula in Equation 6.5. If initial above-ground standing live carbon stocks are below Common Practice, then MBL must be determined using the formula in Equation 6.6.

A graphical example of a baseline meeting these conditions is provided in Figure 6.5 and Figure 6.6. Figure 6.5 shows the baseline before averaging; Figure 6.6 shows the baseline after averaging.

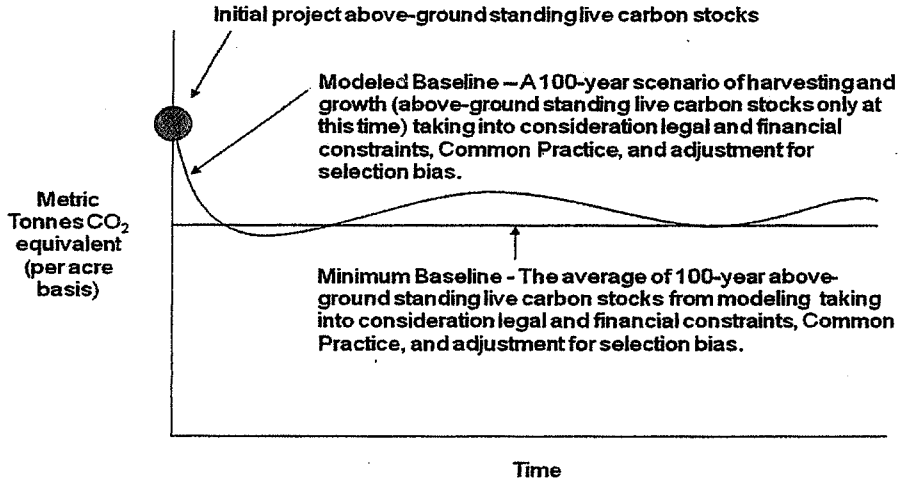


Figure 6.5. Modeling Standing Live Carbon Stocks Where Initial Stocks Are Above Common Practice

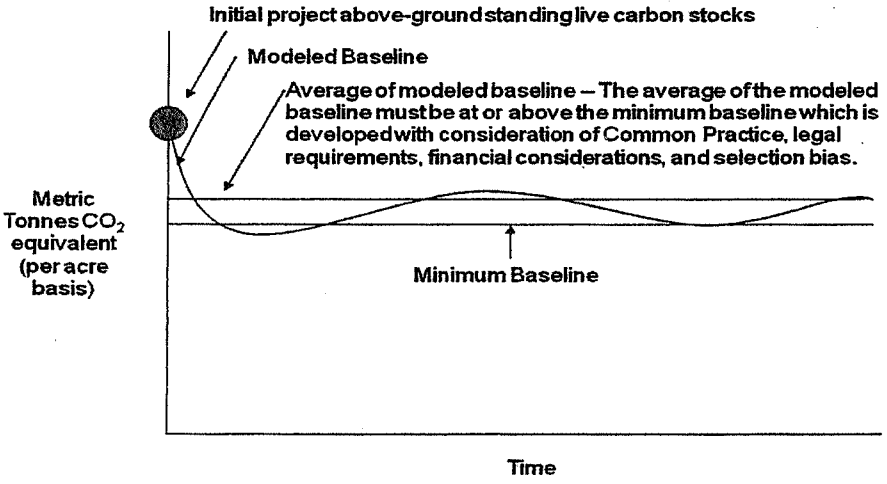


Figure 6.6. Averaging the Modeled Standing Live Carbon Stocks Where Initial Stocks Are Above Common Practice

Equation 6.5. Determining the Minimum Baseline Level Where Initial Stocks Are Above Common Practice

MBL = CP

Where,

MBL = Minimum baseline level (above-ground standing live carbon stocks)

CP = Common Practice (as determined in Step 1)

Equation 6.6. Determining the Minimum Baseline Level Where Initial Stocks Are Below Common Practice

MBL = MAX (MAX (HSR, ICS), MIN (CP, WCS))

Where,

MBL = Minimum baseline level (above-ground standing live carbon stocks)

HSR = The "High Stocking Reference" for the Project Area. The High Stocking Reference is defined as 80 percent of the highest value for above-ground standing live carbon stocks per acre within the Project Area during the preceding 10-year period. To determine the High Stocking Reference, the Offset Project Operator or Authorized Project Designee must document changes in the Project Area's above-ground standing live carbon stocks over the preceding 10 years, or for as long as the Forest Owner has had control of the stocks, whichever is shorter. Figure 6.7 presents a graphical portrayal of a High Stocking Reference determination.

CP = Common Practice (as determined in Step 1)

ICS = Initial above-ground standing live carbon stocks per acre within the Project Area (as determined in Step 2)

WCS = The weighted average above-ground standing live carbon stocks per acre for all Forest Owner (and affiliate) landholdings within the same logical management unit as the Project Area. See Section 6.2.1.1 for requirements and methods for calculating WCS.

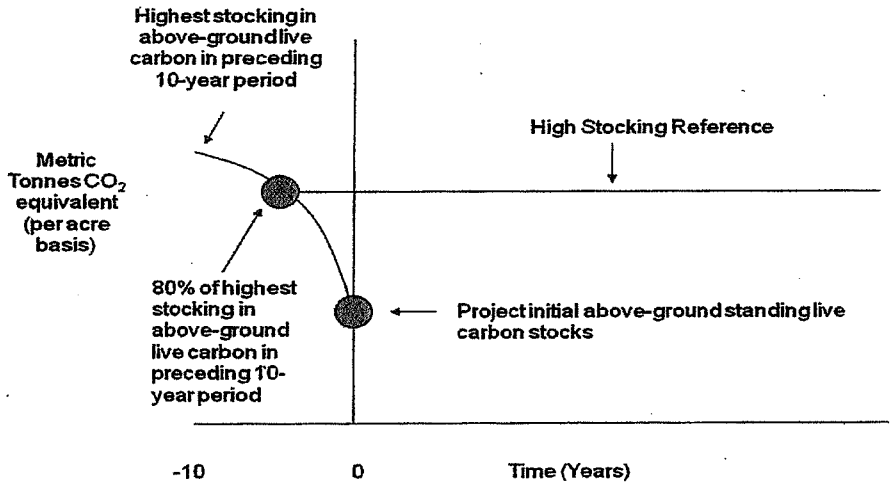


Figure 6.7. Determining a Project Area's High Stocking Reference

It is possible for the High Stocking Reference to be higher than Common Practice, even where initial live-tree carbon stocks for the project are below Common Practice.

Step 4 – Determine the Baseline for All Carbon Pools

Once the baseline for above-ground standing live carbon stocks has been determined, perform the following steps:

1. Estimate baseline carbon stocks for all other required carbon pools identified for the project (including below-ground carbon stocks, as well as standing dead carbon stocks where applicable). These carbon stocks must be modeled or estimated following the requirements and methods in Appendix A and Appendix B.
2. Average the results, so that the baseline for other carbon pools contains the same (average) value for carbon stocks in every year.
3. Sum the above-ground standing live carbon stock baseline and the baseline for all other carbon stocks to produce a final baseline for all carbon pools (see Figure 6.8).

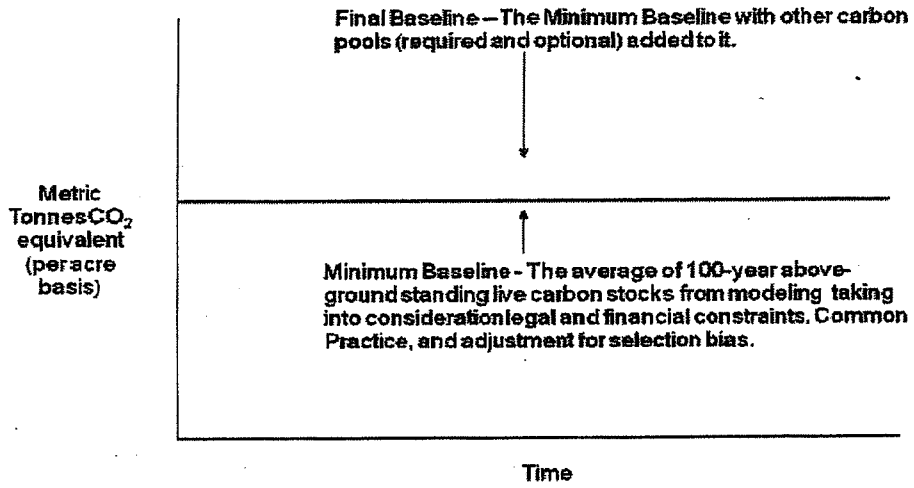


Figure 6.8. Final Baseline Incorporating All Required Carbon Stocks

6.2.1.1 Determining Weighted Average Carbon Stocks (WCS) on Lands in the Same Logical Management Unit as the Project Area

Quantification Methodology
Determining the minimum baseline level (MBL) for an Improved Forest Management project requires a comparison to carbon stocking levels on other lands within the same logical management unit (LMU) as the Project Area. The carbon stocking level within the LMU (expressed as the weighted average above-ground standing live carbon stocks per acre for all lands in the same LMU) is used as a parameter (WCS) for determining the MBL in Equation 6.6.

A "logical management unit" or "LMU" is defined as all land that the Forest Owner and its affiliate(s) (as defined below) either own in fee or hold timber rights on, and which it or they manage as an explicitly defined planning subunit. LMUs are generally characterized by unique biological, geographical, and/or geological conditions, are generally delimited by watershed boundaries and/or elevational zones, and contain unique road networks. In addition, an LMU must:

- Be a sustainable planning subunit as demonstrated by inventory reports and growth and harvest projections for the LMU.
- Where even aged management is utilized, have a uniform distribution (by area) of 10-year age classes that extend to the normal rotation age (variation of any 10-year age class not to exceed 20%).
- Where uneven aged management is utilized, have between 33% and 66% of the forested stands exceeding the retention standards identified in the growth and harvest projections by a minimum of 25% (basal area).

An "affiliate" is defined as any person or entity that, directly or indirectly, through one or more intermediaries, controls or is controlled by or is under common control with the Forest Owner, including any general or limited partnership in which the Forest Owner is a partner and any limited liability company in which the Forest Owner is a member. For the purposes of this definition, "control" means the possession, direct or indirect, of the power to direct or cause the

direction of the management and policies of a person, whether through the ownership of voting securities, by contract or otherwise, and "person" means an individual or a general partnership, limited partnership, corporation, professional corporation, limited liability company, limited liability partnership, joint venture, trust, business trust, cooperative or association or any other legally-recognized entity.

If an explicit, existing LMU containing the Project Area cannot be identified, the LMU must be defined by identifying all lands where the Forest Owner and its affiliate(s) (as defined above) either own in fee or hold timber rights on within the same Assessment Area(s) covered by the Project Area. Assessment Areas covered by the Project Area are identified in Step 1, above, using the information in Appendix F.

To calculate WCS, estimate the above-ground standing live carbon stocks per acre for the entire LMU containing the Project Area (including the Project Area itself). This can be done using either existing inventory data, or a stratified vegetation-type analysis.

6.2.1.1.1 Calculating WCS Using Inventory Data

Quantification Methodology

If sufficient inventory data for LMU lands exist to quantify above-ground standing live carbon stocks for the entire LMU, then the formula in Equation 6.7 must be used to calculate WCS.

Equation 6.7. Formula for WCS Using Inventory Data

$$If \left|\left(1-\frac{ECS}{ICS}\right)\right| \leq 0.2, then\ WCS = ICS$$

$$If \left|\left(1-\frac{ECS}{ICS}\right)\right| > 0.2, then\ WCS = \frac{ICS \cdot PA + ECS \cdot EA}{PA + EA}$$

Where,

WCS = The weighted average above-ground standing live carbon stocks per acre within the LMU containing the Project Area

ICS = Initial above-ground standing live carbon stocks per acre within the Project Area

PA = Size of the Project Area in acres

ECS = Above-ground standing live carbon stocks per acre within the LMU *but excluding the Project Area* (EA), as determined from existing inventory data

EA = Size of the LMU in acres, e*xcluding the Project Area*

6.2.1.1.2 Calculating WCS Using Stratified Vegetation-Type Analysis

Quantification Methodology

If sufficient inventory data is not available for the LMU, a stratified vegetation-type analysis must be used to calculate WCS. To conduct this analysis, all landholdings within the LMU – including the Project Area – must be divided into vegetation types and size class/canopy cover categories as delimited in Table 6.2 with a resolution for classification no greater than 40 acres. Each vegetation class has a "carbon rating" provided in Table 6.2. WCS must be calculated using the

ratio of average carbon stocking on LMU lands relative to carbon stocking on Project Area lands (referred to as the "stratified carbon weighting factor" or SWF). The required formulas are specified in Equation 6.8 and Equation 6.9.

Equation 6.8. Formula for WCS Using Stratified Vegetation-Type Analysis

$$If \left|\left(1-\frac{ECS}{ICS}\right)\right| \leq 0.2, then\ WCS = ICS$$

$$If \left|\left(1-\frac{ECS}{ICS}\right)\right| > 0.2, then\ WCS = \frac{ICS \cdot PA + SWF \cdot ICS \cdot EA}{PA + EA}$$

Where,

WCS = The weighted average above-ground standing live carbon stocks per acre within the LMU containing the Project Area

ICS = Initial above-ground standing live carbon stocks per acre within the Project Area

PA = Size of the Project Area in acres

SWF = The stratified carbon weighting factor for the LMU (from Equation 6.9 below)

EA = Size of the LMU in acres, e*xcluding the Project Area*

Equation 6.9. Formula for LMU Stratified Carbon Weighting Factor

$$SWF = \frac{\sum_i (PA_i \cdot CR_i)}{\sum_i PA_i} \div \frac{\sum_i (EA_i \cdot CR_i)}{\sum_i EA_i}$$

Where,

PA_i = Acres of the Project Area in forest vegetation type *i* (from Table 6.2)

EA_i = Acres of the LMU, e*xcluding the Project Area,* in forest vegetation type *i* (from Table 6.2)

CR_i = Carbon rating for forest vegetation type *i* (from Table 6.2)

Table 6.2. Vegetation Classes for Stratification

Forest Vegetation Description	Average Diameter (Breast Height)	Average Canopy Cover	Carbon Rating (metric tons CO_2e)
Brush	0"	NA	0
Regeneration	3"	NA	0.5
Pole-sized trees	6" - 12"	< 33%	2
Pole-sized trees	6" - 12"	33% - 66%	4
Pole-sized trees	6" - 12"	>66%	6

Small Sawlogs	12" - 20"	< 33%	4
Small Sawlogs	12" - 20"	33% - 66%	8
Small Sawlogs	12" - 20"	>66%	12
Large Sawlogs	20" - 36"	< 33%	8
Large Sawlogs	20" - 36"	33% - 66%	16
Large Sawlogs	20" - 36"	>66%	24
Very Large Trees	>36"	< 33%	16
Very Large Trees	>36"	33% - 66%	32
Very Large Trees	>36"	>66%	48

6.2.1.2 Consideration of Legal Constraints

In modeling the baseline for standing live carbon stocks, all legal constraints that could affect baseline growth and harvesting scenarios must be incorporated. The standing live carbon stock baseline must represent a growth and harvesting regime that fulfills all legal requirements. Voluntary agreements that can be rescinded, such as rental contracts and forest certifications are not legal constraints. Habitat Conservation Plans (HCPs) and Safe Harbor Agreements (SHAs) that are in place more than one year prior to the project's start date shall be modeled as legal constraints. HCPs and SHAs that are approved after the date one year prior to the offset project's commencement date are not considered legal constraints for the purpose of baseline modeling and may be disregarded.

Legal constraints include all laws, regulations, and legally-binding commitments applicable to the Project Area at the time of offset project commencement that could affect standing live carbon stocks. Legal constraints include:

1. Federal, state/provincial, or local government regulations that are required and might reasonably be anticipated to influence carbon stocking over time including, but not limited to:
    a. Zones with harvest restrictions (e.g. buffers, streamside protection zones, wildlife protection zones)
    b. Harvest adjacency restrictions
    c. Minimum stocking standards
2. Forest practice rules, or applicable Best Management Practices established by federal, state, provincial or local government that relate to forest management.
3. Other legally binding requirements affecting carbon stocks including, but not limited to, covenants, conditions and restrictions, and other title restrictions in place prior to or at the time of project initiation, including pre-existing conservation easements, Habitat Conservation Plans, Safe Harbor Agreements, and deed restrictions, excepting an encumbrance that was put in place and/or recorded less than one year prior to the project start date, as defined in Section 3.5.

For forest projects located in California, the baseline must be modeled to reflect all silvicultural treatments associated with timber harvest plans (THPs) active within the Project Area at the time of the project's initiation. All legally enforceable silvicultural and operational provisions of a THP – including those operational provisions designed to meet California Forest Practice Rules requirements for achieving Maximum Sustained Production of High Quality Wood Products [14 CCR 913.11 (933.11, 953.11)] – are considered legal constraints and must be reflected in

baseline modeling for as long as the THP will remain active. For portions of the Project Area not subject to THPs (or over time periods for which THPs will not be active), baseline carbon stocks must be modeled by taking into account any applicable requirements of the California Forest Practice Rules and all other applicable laws, regulations, and legally binding commitments that could affect onsite carbon stocks. On a case-by-case basis, the California Department of Forestry and Fire Protection (Cal FIRE) may assist in identifying minimum carbon stocking levels that would be effectively required under California Forest Practice Rules.

6.2.1.3 Consideration of Financial Constraints

In modeling the baseline for standing live carbon stocks, financial constraints that could affect baseline growth and harvesting scenarios must be included. It must be demonstrated that the growth and harvesting regime assumed for the baseline is financially feasible through one of the following means:

1. A financial analysis of the anticipated growth and harvesting regime that captures all relevant costs and returns, taking into consideration all legal, physical, and biological constraints. Cost and revenue variables in the financial analysis may be based on regional norms or on documented costs and returns for the Project Area or other properties in the project's Assessment Area.
2. Providing evidence that activities similar to the proposed baseline growth and harvesting regime have taken place on other properties within the Forest Project's Assessment Area within the past 15 years. The evidence must demonstrate that harvesting activities have taken place on at least one other comparable site with:
    a. Slopes that do not exceed slopes in the Project Area by more than 10 percent
    b. An equivalent zoning class to the Project Area
    c. Comparable species composition to the Project Area (i.e. within 20 percent of project species composition based on trees per acre)

6.2.2 Estimating Baseline Onsite Carbon Stocks – Public Lands

Quantification Methodology

For Improved Forest Management Projects on lands owned or controlled by public agencies, the baseline must be estimated by:

1. Conducting an initial forest carbon inventory for the Project Area
2. Projecting future changes to Project Area forest carbon stocks by:
    a. Extrapolating from historical trends
    b. Anticipating how current and future public policy will affect onsite carbon stocks

The method that results in the highest estimated carbon stock levels must be used to determine the baseline.

To extrapolate from historical trends:

- For Project Areas that have a ten-year history of declining carbon stocks, the baseline must be defined by the average of the carbon stocks over the past ten years and considered static for the project life (i.e. the same level of carbon stocks is assumed in every year).
- For Project Areas that demonstrate an increasing inventory of carbon stocks over the past ten years, the growth trajectory of the baseline shall continue until the forest (under

the baseline stocks) achieves a stand composition consistent with comparable forested areas that have been relatively free of harvest over the past 60 years.

To anticipate how current and future public policy will affect onsite carbon stocks, the baseline must be modeled following the requirements and methods in Appendix B incorporating constraints imposed by all applicable statutes, regulations, policies, plans and Activity-Based Funding.

6.2.3 Estimating Baseline Carbon in Harvested Wood Products

Quantification Methodology

To estimate the amount of baseline carbon transferred to long-term storage in wood products each year, the following steps must be performed:

1. Determine the *average* amount of carbon in standing live carbon stocks (prior to delivery to a mill) that would have been harvested in each year of the baseline over 100 years. The result will be a uniform estimate of harvested carbon in each year of the baseline. This estimate is determined at the project outset, using the same biomass equations used to calculate biomass in live trees, and will not change over the course of the project.
    a. For projects on private lands, the amount of harvested carbon must be derived from the growth and harvesting regime used to develop the baseline for onsite carbon stocks in Section 6.2.1.
    b. For projects on public lands, the amount of harvested carbon must be derived from the growth and harvesting regime assumed in the baseline for onsite carbon stocks derived in Section 6.2.2.
2. On an annual basis, determine the amount of harvested carbon that would have remained stored in wood products, averaged over 100 years, following the requirements and methods in Appendix C.

6.2.4 Determining Actual Onsite Carbon Stocks

Quantification Methodology

Actual carbon stocks for Improved Forest Management projects must be determined by updating the Project Area's forest carbon inventory. This is done by:

1. Incorporating any new forest inventory data obtained during the previous year into the inventory estimate. Any plots sampled during the previous year must be incorporated into the inventory estimate.
2. Using an approved model to "grow" (project forward) prior-year data from existing forest inventory plots to the current reporting year. Approved growth models and requirements and methods for projecting forest inventory plot data using models is provided in Appendix B.
3. Updating the forest inventory estimate for harvests and/or disturbances that have occurred during the previous year.
4. Applying an appropriate confidence deduction for the inventory based on its statistical uncertainty, following the requirements and methods in Appendix A, Section A.4.

6.2.5 Determining Actual Carbon in Harvested Wood Products

Quantification Methodology

Perform the following steps to determine actual carbon in harvested wood products:

1. Determine the actual amount of carbon in standing live carbon stocks (prior to delivery to a mill) harvested in the current year (based on harvest volumes determined in Section 6.2.4).
2. Determine the amount of actual harvested carbon that will remain stored in wood products, averaged over 100 years, following the requirements and methods in Appendix C.

6.2.6 Quantifying Secondary Effects

Quantification Methodology

For Improved Forest Management Projects, significant Secondary Effects can occur if a project reduces harvesting in the Project Area, resulting in an increase in harvesting on other properties. Equation 6.10 must be used to estimate Secondary Effects for Improved Forest Management projects:

Equation 6.10. Secondary Effects Emissions

$$If \sum_{n=1}^{y-1} (AC_{hv,n} - BC_{hv,n}) > 0, then\ SE_y = 0$$

$$If \sum_{n=1}^{y-1} (AC_{hv,n} - BC_{hv,n}) < 0, then\ SE_y = (AC_{hv,y} - BC_{hv,y}) \times 20\%$$

Where,

SE_y	=	Estimated annual Secondary Effects (used in Equation 6.1.)
$AC_{hv,n}$	=	Actual amount of onsite carbon harvested in reporting period n (prior to delivery to a mill), expressed in CO_2-equivalent tons
$BC_{hv,n}$	=	Estimated average baseline amount of onsite carbon harvested in reporting period n (prior to delivery to a mill), expressed in CO_2-equivalent tons, as determined in Step 1 of Section 6.2.3
y	=	The current year or reporting period

6.3 Avoided Conversion Projects

6.3.1 Estimating Baseline Onsite Carbon Stocks

Quantification Methodology

The baseline for Avoided Conversion Projects is a projection of onsite forest carbon stock losses that would have occurred over time due to the conversion of the Project Area to a non-forest land use. Estimating the baseline for Avoided Conversion Projects involves two steps:

1. Characterizing and projecting the baseline
2. Discount for the uncertainty of conversion probability

Step 1 - Characterizing and Projecting the Baseline

The project the baseline must be characterized by:

1. Clearly specifying an alternative highest-value land use for the Project Area, as identified by an appraisal (required in Section 3.1.2.3).
2. Estimating the rate of conversion and removal of onsite carbon stocks. The rate of conversion and removal of onsite carbon stocks must be estimated by either:
    a. Referencing planning documentation for the Project Area (e.g. construction documents or plans) that specifies the timeframe of the conversion and intended removal of forest cover on the Project Area; or
    b. In the absence of specific documentation, identifying default Total Conversion Impact and Annual Conversion values from Table 6.3.
3. Using a computer simulation to project changes in onsite carbon stocks over 100 years, reflecting the rate of conversion estimated in (2). The simulation must model changes in onsite carbon stocks for all required and selected optional carbon pools, as identified in Section 5.3.

Table 6.3. Default Avoided Conversion

Type of Conversion Identified in Appraisal	Total Conversion Impact This is the assumed total effect over time of the conversion activity. (The total conversion impact is amortized over a 10-year period to determine the annual conversion in the next column.)	Annual Conversion This is the assumed annual conversion activity. The percentages below are multiplied by the initial onsite carbon stocks for the project on an annual basis for the first 10 years of the project.
Residential	Estimate using the following formula: TC = min(100, (P*3 / PA)*100) *Where:* TC = % total conversion (TC cannot exceed 100%) PA = the Project Area (acres) identified in the appraisal P = the number of unique parcels that would be formed on the project area as	Estimate using the following formula: AC = TC / 10 *Where:* AC = % annualized conversion TC = % total conversion

	identified in the appraisal *Each parcel is assumed to deforest 3 acres of forest vegetation.	
Mining and agricultural conversion, including pasture or crops	90%	9.0%
Golf course	80%	8.0%
Commercial buildings	95%	9.5%

The computer simulation of the baseline must apply the identified rate of conversion over time to estimate changes in onsite carbon stocks, beginning with the Project Area's initial onsite carbon stocks.

If the projected conversion rate does not result in a complete removal of onsite forest carbon stocks, the baseline projection should account for any residual forest carbon value as a steady condition for the balance of a 100-year projection.

Step 2 - Discount for Uncertainty of Conversion Probability

If the fair market value of the anticipated alternative land use for the Project Area (as determined by the appraisal required in Section 3.1.2.3) is *not more than 80 percent greater* than the value of the current forested land use, then a discount must be applied each year to the project's quantified GHG reductions and removals. If quantified GHG reductions and removals for the year are positive (i.e. $[(\Delta AC_{onsite} - \Delta BC_{onsite}) + (AC_{wp,y} - BC_{wp,y}) * 80\% + SE_y] > 0$ in Equation 6.1) then use the following formula (Equation 6.11) to calculate the appropriate Avoided Conversion Discount factor, ACD. If quantified GHG reductions and removals for the year are negative, then ACD must equal zero.

Equation 6.11. Avoided Conversion Discount Factor

If $0.4 < ((VA / VP) - 1) < 0.8$, **then** $ACD = [80\% - ((VA / VP) - 1)] \times 2.5$
If $((VA / VP) - 1) > 0.8$, **then** $ACD = 0\%$
If $((VA / VP) - 1) < 0.4$, **then** $ACD = 100\%$

Where,

ACD = The Avoided Conversion Project discount factor (used in Equation 6.1).

VA = The appraised fair market value of the anticipated alternative land use for the Project Area

VP = The appraised fair market value of the current forested land use for the Project Area

6.3.2 Estimating Baseline Carbon in Harvested Wood Products

Quantification Methodology

Harvesting is assumed to occur in the baseline over time as the Project Area is converted to another land use. To estimate the baseline carbon transferred to long-term storage in harvested wood products each year:

1. Determine the amount of carbon in standing live carbon stocks (prior to delivery to a mill) that would have been harvested in each year, consistent with the rate of reduction in baseline standing live carbon stocks determined in Section 6.3.1. This projection is determined at the project outset, using the same biomass equations used to calculate biomass in live trees, and will not change over the course of the project.
2. On an annual basis, determine the amount of harvested carbon that would have remained stored in wood products, averaged over 100 years, following the requirements and methods in Appendix C.

6.3.3 Determining Actual Onsite Carbon Stocks

Quantification Methodology

Actual carbon stocks for Avoided Conversion Projects must be determined by updating the Project Area's forest carbon inventory. This is done by:

1. Incorporating any new forest inventory data obtained during the previous year into the inventory estimate. Any plots sampled during the previous year must be incorporated into the inventory estimate.
2. Using an approved model to "grow" (project forward) prior-year data from existing forest inventory plots to the current reporting year. Approved growth models are identified in Appendix B. Methods for projecting forest inventory plot data using models is also provided in Appendix B.
3. Updating the forest inventory estimate for harvests and/or disturbances that have occurred during the previous year.
4. Applying an appropriate confidence deduction for the inventory based on its statistical uncertainty, following the requirements and methods in Appendix A, Section A.4.

6.3.4 Determining Actual Carbon in Harvested Wood Products

Quantification Methodology

Perform the following steps to determine actual carbon in harvested wood products:

1. Determine the actual amount of carbon in standing live carbon stocks (prior to delivery to a mill) harvested in the current year (based on harvest volumes determined in Section 6.3.3).
2. Determine the amount of actual harvested carbon that will remain stored in wood products, averaged over 100 years, following the requirements and methods in Appendix C.

6.3.5 Quantifying Secondary Effects

Quantification Methodology

Significant Secondary Effects for Avoided Conversion projects can arise if the type of land use conversion that would have happened on the Project Area is shifted to other forest land.

To quantify Secondary Effects for Avoided Conversion projects, use Equation 6.12.

The value for Secondary Effect emissions will always be negative or zero.

Equation 6.12. Secondary Effects Emissions

$$\mathbf{SE_y = (-1) \times CDR\% \times (\Delta\ AC_{onsite} - \Delta\ BC_{onsite})\ or\ 0}$$, whichever is lower

Where,

SE_y	=	Secondary Effect GHG emissions caused by the project activity in year y (Equation 6.1)
CDR	=	Conversion displacement risk value, assumed to be 3.6% for all forest lands
$\Delta\ AC_{onsite}$	=	Annual difference in actual onsite carbon (CO_2e) as defined in Equation 6.1
$\Delta\ BC_{onsite}$	=	Annual difference in baseline onsite carbon (CO_2e) as defined in Equation 6.1

7 Ensuring the Permanence of Credited GHG Reductions and Removals

The Cap and Trade Regulation requires that credited GHG reductions and removals be "permanent." Permanence of Forest project GHG reductions and removals is addressed through three mechanisms:

1. The requirement for all projects to monitor onsite carbon stocks, submit annual Offset Project Data Reports, and undergo third-party verification of those reports with site visits at least every six years for the duration of the Project Life.
2. The regulatory obligation for all intentional reversals of GHG reductions and removals be compensated for through retirement of other Compliance Instruments .
3. The maintenance of a Forest Buffer Account by ARB to provide insurance against reversals of GHG reductions and removals due to unintentional causes (including natural disturbances such a fires, pest infestations, or disease outbreaks).

GHG reductions and removals can be "reversed" if the stored carbon associated with them is released (back) to the atmosphere. Many biological and non-biological agents, both natural and human-induced, can cause reversals. Some of these agents cannot completely be controlled and may therefore result in an unintentional reversal, such as natural agents like fire, insects, and wind. Other agents can be controlled, such as the human activities like land conversion and over-harvesting. Under this protocol, reversals due to controllable agents are considered intentional as defined in the Regulation. The Offset Project Operator or Authorized Project Designee is required to identify and quantify the risk of reversals from different agents based on project-specific circumstances. The resulting risk rating determines the quantity of Offset Credits that the project must contribute to the Forest Buffer Account to insure against unintentional reversals.

7.1 Identifying a Reversal

The Offset Project Operator or Authorized Project Designee must demonstrate, through annual reporting and periodic verification, that stocks associated with credited GHG reductions and removals are maintained for a period of time considered to be permanent. For purposes of this protocol 100 years is considered permanent. If the quantified GHG reductions and removals (i.e. QR_y in Equation 6.1) in a given year are negative, and Offset Credits were issued to the Forest Project in any previous year, it is considered a reversal, regardless of the cause of the decrease. Planned thinning or harvesting activities, for example, may cause a reversal if they result in a negative value for QR_y.

7.2 Insuring Against Reversals

Unintentional reversals are insured against by contributing a percentage of ARB-issued Offset Credits to a Forest Buffer Account. The amount of the contribution is based on a project-specific risk evaluation.

7.2.1 About the Forest Buffer Account

A Forest Buffer Account is a holding account for Offset Credits issued to Forest Project, which is administered by ARB. All Forest Projects must contribute a percentage of Offset Credits to the Buffer Account any time Offset Credits are issued by ARB for verified GHG reductions and removals. Each Forest Project's contribution is determined by a project-specific risk rating, as

described in Section 7.2.2. If a Forest Project experiences an unintentional reversal of credited GHG reductions and removals (as defined in Section 7.3), Offset Credits from the Forest Buffer Account will be retired in an amount equal to the total amount of carbon that was reversed (measured in metric tons of CO_2-equivalent) according to the process identified in the Regulation and Section 7 of this protocol. A Forest Buffer Account therefore acts as a general insurance mechanism against unintentional reversals for Offset Credits issued to Forest Projects.

7.2.2 Contributions to the Forest Buffer Account

Each time Offset Credits are issued by ARB for verified GHG reductions and removals achieved by a Forest Project, a certain percentage of those Offset Credits must be contributed to a Forest Buffer Account. The size of the contribution to the Forest Buffer Account will depend on the Forest Project's risk rating for reversals. For example, if a Forest Project is issued 10 Offset Credits after verification, and the project's reversal risk rating is 10 percent, then 9 Offset Credits will be issued to the Offset Project Operator or Authorized Project Designee, and 1 Offset Credit must be deposited in the Forest Buffer Account.

The Offset Project Operator or Authorized Project Designee must determine the reversal risk rating for a project by following the requirements and methods in Appendix D. The risk rating must be determined prior to listing, and recalculated in every year the project undergoes verification. Forest Owners who record a Qualified Conservation Easement in conjunction with implementing a Forest Project will receive a lower risk rating (see Appendix D).

7.3 Compensating for Reversals

ARB requires that all reversals be compensated through the retirement of Compliance Instruments. If a reversal associated with a Forest Project is found to have been unintentional as defined in the Regulation, then ARB will compensate for the reversal on the behalf of the Offset Project Operator or Authorized Project Designee by retiring Offset Credits from the Forest Buffer Account. If a reversal is found to be intentional as defined in the Regulation, then the Offset Project Operator or Authorized Project Designee must compensate for the reversal by surrendering Compliance Instruments from its own account.

7.3.1 Unintentional Reversals

An Unintentional Reversal is any reversal not due to the Forest Owner's negligence, gross negligence or willful intent, including wildfires or disease, that are not the result of the Forest Owner's negligence, gross negligence or willful intent. Requirements for Unintentional Reversals are as follows:

1. If there has been an Unintentional Reversal, the Offset Project Operator or Authorized Project Designee must notify ARB or the approved offset registry where the project is listed in writing of the Unintentional Reversal within six months of its occurrence.
2. The Offset Project Operator or Authorized Project Designee must explain the nature of the Unintentional Reversal and provide a verified estimate of onsite carbon stocks within one year so that the reversal can be quantified (in units of CO_2-equivalent metric tons).

If ARB determines that there has been an Unintentional Reversal, it will retire a quantity of Offset Credits from the Forest Buffer Account equal to the quantity of the reversed carbon in CO_2-equivalent metric tons.

7.3.2 Intentional Reversals

An Intentional Reversal is any reversal that is due to the Forest Owner's negligence, gross negligence, or willful intent, including harvesting, development, and harm to the Project Area. Requirements for Intentional Reversals are as follows:

1. If an Intentional Reversal has occurred, written notice must be provided to ARB within thirty days calendar days. Additionally, if ARB or an approved Offset Project Registry determines that an Intentional Reversal has occurred, it shall deliver written notice to the Offset Project Operator or Authorized Project Designee.
2. Within thirty days of ARB receiving the intentional reversal notice, the Offset Project Operator or Authorized Project Designee must provide a written description and explanation of the reversal to ARB.
3. Within three months of ARB receiving the intentional reversal notice, the Offset Project Operator or Authorized Project Designee must provide ARB with a verified estimate of current onsite carbon stocks;
4. Within four months of ARB receiving the intentional reversal notice, the Offset Project Operator or Authorized Project Designee must retire a quantity of Compliance Instruments equal to the quantity of the reversed carbon in CO_2-equivalent metric tons.

7.4 Disposition of Forest Projects After a Reversal

If a reversal lowers the Forest Project's actual standing live carbon stocks below its approved baseline standing live carbon stocks, the Forest Project will automatically be terminated. In this circumstance, the original approved baseline for the project would no longer be valid. If the Forest Project is automatically terminated due to an Unintentional Reversal, another project may be initiated on the same Project Area. New projects may not be initiated on the same Project Area if a Forest Project is terminated due to an Intentional Reversal.

If a Forest Project has experienced a reversal and its actual standing live carbon stocks are still above the approved baseline levels, it may continue without termination as long as the reversal has been compensated. The project must continue contributing to the Forest Buffer Account in future years based on its verified risk rating.

8 Project Monitoring

Monitoring is the process of regularly collecting and reporting data related to a project's performance. Annual monitoring of Forest Projects is required to ensure up-to-date estimates of project carbon stocks and provide assurance that GHG reductions or removals achieved by a project have not been reversed. The Offset Project Operator or Authorized Project Designee must conduct monitoring activities and submit Offset Project Data Reports on an annual basis. Monitoring is required for a period of 100 years following the final issuance of any Offset Credits to a project.

For Forest Projects, monitoring activities consist primarily of updating a project's forest carbon inventory. ARB requires a complete inventory of carbon stocks to be reported each year. This complete inventory must be maintained and updated throughout the Project Life.

8.1 Forest Carbon Inventory Program

Prior to a Forest Project's first verification, a documented forest carbon inventory program, including an inventory monitoring plan and a modeling plan, must be established detailing the specific methods that will be used to update the project's forest carbon inventory on an annual basis. The forest carbon inventory program must adhere to the requirements and methods in Appendices A and B, which establish the equations for computing biomass and limits to which computer models can be used in the inventory update process.

8.2 Annual Monitoring Requirements

The Offset Project Operator or Authorized Project Designee is required to report the Forest Project's onsite carbon stocks each year in an Offset Project Data Report. The offset project data report must include an estimate of carbon stocks in all required carbon pools. The estimate must reflect the appropriate confidence deduction as determined by the steps in Appendix A, Section A.4. Annual onsite carbon stock estimates are computed from inventory data. Inventory data are updated annually by:

1. Incorporating any new forest inventory data obtained during the previous year.
2. Modeling growth in sample plots using approved growth models and stand table projection methods (see Appendix B regarding growth models and stand table projections).
3. Updating the forest inventory data for harvests and/or disturbances that have occurred during the previous year.

Specific methods used to update the forest inventory must follow the inventory methodologies approved at the time the project is initially verified. Modifications to inventory methodologies must be approved in advance by a third-party verification body and by ARB, and documented in the change log.

9 Reporting Requirements

This section provides requirements for reporting. Offset Project Data Reports must be submitted at the conclusion of every project reporting period.

9.1 Project Documentation

In order for the project to be Listed, all of the information specified in the Project Listing Requirements in Section 9.1.1 must be submitted, along with any additional information specified in the Regulation. An Offset Project Data Report must be submitted each year. Offset Credits may be issued following verification of an offset project data report. Record keeping requirements are detailed in §95976 of the Regulation, and all specified records must be retained for 100 years following the issuance of any Offset Credits.

All reports that reference carbon stocks must be submitted with the oversight of a Professional Forester. If the project is located in a jurisdiction without a Professional Forester law or regulation, then a Professional Forester is must either have the Certified Forester credentials managed by the Society of American Foresters, or other valid professional forester license or credential approved by a government agency in a different jurisdiction.

9.1.1 Project Listing Requirements

The listing information in this section must be submitted by the Offset Project Operator or Authorized Project Designee prior to the Listing of the project. This information is also submitted as part of the first Offset Project Data Report, and is subject to verification at the initial project verification. The following listing information must be submitted no later than the date at which the Offset Project Operator or Authorized Project Designee must submit the first Offset Project Data Report:

9.1.1.1 All Projects[7]

1. Project Name.
2. Project Contact Information, including name, phone number, address, and email address for:
   a. Offset Project Operator
   b. Authorized Project Designee (if applicable);
3. Whether the Offset Project Operator is the owner in fee for the project area.
   a. If yes, provide documentation (e.g. deed of trust, title report) showing the Offset Project Operator's ownership interest in the property and its interest in the trees and standing timber on the property.
   b. If no, explain how the entity identified as the Offset Project Operator has the right to undertake and list the project.
4. Project Type (reforestation, improved forest management, or avoided conversion).
5. A description of the management activities that will lead to increased carbon stocks in the Project Area, compared to the baseline.
6. Indicate if the project occurs on public, private or tribal lands.

[7] Reforestation projects as qualified in section 6.1 can defer the items that are marked with an asterisk until the second site-visit verification.

7. Project commencement date, with an explanation and justification of the commencement date.
    a. Specify the action(s) that identify the commencement date.
8. A statement as to whether any GHG reductions or removals associated with the Project Lands have ever been listed or registered with, or otherwise claimed by, another registry or program, or sold to a third party prior to listing, including;
    a. Have any lands within the Project Area ever been listed or registered with an offset project registry or program in the past?
    b. Have greenhouse gas emission reductions or removal enhancements associated with lands within the Project Area been credited or claimed for the purpose of greenhouse gas mitigation or reduction goals, whether in a voluntary or regulatory context?
    c. If yes, identify the registry or program (include vintages and reporting period).
9. A statement as to whether the project is being implemented and conducted as the result of any law, statute, regulation, court order, or other legally binding mandate? If yes, explain.
10. Declaration that the project does *not* employ broadcast fertilization.
11. If the Forest Project is located on public land, a description and copies of the documentation demonstrating explicit approval of the project's management activities and baseline including any public vetting processes necessary to evaluate management and policy decisions concerning the project.
12. If the Forest Project is located in tribal areas, a description and copies of documentation demonstrating that the land within the Project Area is owned by a tribe or private entities.
13. If commercial harvesting is either planned or ongoing within the Project Area, a description of how the Forest Owner satisfies one of the three requirements for employing and demonstrating sustainable long-term harvesting practices on all of its forest landholdings (refer to Section 3.8.1).
14. A description of how the project meets (or will meet) the definition of "Natural Forest Management" (refer to Section 3.8.2), including:
    a. Composition of native species;
    b. Distribution of age classes / sustainable managment;
    c. Structural elements (standing and lying dead wood);
15. Descriptions and maps of the Project Area boundaries that include:
    a. Governing jurisdictions, and latitude/longitude coordinates
    b. Public and private roads (map)
    c. Towns (map)
    d. Major watercourses (4th order or greater), water bodies, and watershed description (map)
    e. Topography (map)
    f. Townships, ranges, and sections or latitude and longitude (map)
    g. Existing land cover and land use (description with optional map)
    h. Forest vegetation types (description with optional map)
    i. Site classes (description with optional map)
    j. Land pressures and climate zone/classification (description with optional map)
    k. Historical land uses, current zoning, and projected land use within project area and surrounding areas (description with optional map)
16. Identify what assessment area or areas contain lands within the Project Area.
    a. Include how many acres of project lands fall within each assessment area.
    b. Include a value for total project area acreage.
17. General description of the forest conditions within the Project Area:

   a. Species (tree) composition;
   b. Age class distribution;
   c. Management history;
18. Indicate whether the project will employ a Qualified Conservation Easement.
   a. If yes, include the date the Qualified Conservation Easement was or will be recorded, the terms that affect forest management within the easement, and a provide a copy of the Qualified Conservation Easement to ARB.
19. *A description of the inventory methodology for each of the carbon pools included in the Forest Project's Offset Project Boundary. The inventory methodology must describe:
   a. The stratification rules and processes, if applicable.
   b. The sampling process, including selection of plot locations, monumenting of plots, frequency of sampling efforts, data gathering procedures, and parameters of data collected.
   c. Data management and analytical systems.
   d. An inventory monitoring plan including the annual inventory update processes, and the adjustments for harvest, growth, and disturbances over time.
   e. Methods for quality control.
20. *A description of the calculation methodologies for determining metric tons per hectare for each of the carbon pools included in the project report.
21. *A modeling plan, following the requirements and methods in Appendix B, Section B.3.
22. A diagram of the final baseline incorporating all required carbon stocks.
23. *A summary of the inventory of carbon stocks for each carbon pool.
24. *A summary of inventory confidence statistics.
25. *A description and estimate of the Forest Project's baseline onsite carbon stocks. Baseline onsite carbon stocks must be portrayed in a graph depicting time in the x-axis and metric tons CO_2-equivalent in the y-axis. The graph should be supported with written characterizations that explain any annual changes in baseline carbon stocks over time.
26. *An estimate of carbon that will be stored long-term in harvested wood products in the baseline.
27. *Projections of baseline and actual harvesting volumes from the Project Area over 100 years.
28. *Calculation of the project's reversal risk rating and contribution to the Forest Buffer Account.

9.1.1.2 Reforestation Projects

In addition to the information in Section 9.1.1.1, the following information must be provided for Reforestation projects:

1. An explanation of how the Project Lands, at the time of project initiation, meets the eligibility requirements of a) less than 10 percent tree canopy cover for a minimum of 10 years; or b) subject to a significant disturbance that has removed at least 20 percent of the land's above-ground live biomass. The explanation should include why the forest was out of forest cover or a description of the disturbance if a natural significant disturbance occurred.
2. For a Reforestation Project that occurs on land that has undergone a recent Significant Disturbance, indicate the eligibility scenario pertaining to the project site as identified in Appendix E, or a description of how the Forest Project occurs on a type of land for which the Forest Owner has not historically engaged in or allowed timber harvesting.

3. A qualitative characterization of baseline conditions, including an assessment of the likely vegetative conditions and activities that would have occurred in the absence of the project, taking into consideration any laws, statutes, regulations, or other legal mandates that would encourage or require reforestation on the Project Area. The qualitative assessment shall include an assessment of the commercial value of trees within the project area over the next 30 years.
4. List any laws, statutes, regulations or other legal mandates that would encourage or require reforestation on the project area.

9.1.1.3 Improved Forest Management Projects on Private Lands

In addition to the information in Section 9.1.1.1, the following information must be provided for Improved Forest Management projects on private lands:

1. Documentation that the Project Area has greater than 10 percent tree canopy cover.
2. A determination of how the Forest Project's initial standing live carbon stocks compare to Common Practice, as required in Section 6.2.1.
3. If the Forest Project's initial standing live carbon stocks are below Common Practice, a determination of the "High Stocking Reference" for the Project Area. The High Stocking Reference is defined as 80 percent of the highest carbon stocks in live trees during the preceding 10-year period. To determine the High Stocking Reference, changes in the Project Area's live-tree carbon stocks over the preceding 10 years, or as long as the Forest Owner has had control of the stocks must be documented.
    a. Include an affidavit testifying that the inventory depicted over the past 10 years is reasonably accurate.
    b. Include a summary of volume harvested over the past 10 years.
4. Documentation of any and all legal constraints affecting forest management activities on the Project Area. The documentation of legal constraints must include:
    a. A description of each constraint (refer to Section 6.2.1.2).
    b. A narrative that describes the effect of the constraint on forest management.
    c. A description of the modeling techniques used to simulate the effects of the constraint.
5. A demonstration that the growth and harvesting regime assumed for the baseline is financially feasible following the requirements of Section 6.2.1.3.

9.1.1.4 Improved Forest Management Projects on Public Lands

In addition to the information in Section 9.1.1.1, the following information must be provided for Improved Forest Management projects on public lands:

1. Documentation demonstrating that the project takes place on land that has greater than 10 percent tree canopy cover.
2. A projection of future changes to Project Area forest carbon stocks by extrapolating from historical trends; and anticipating how current and future public policy will affect onsite carbon stocks per the requirements of Section 6.2.2.
3. An explanation of how current and future public policy will affect onsite carbon stocks and how, the baseline modeling incorporates constraints imposed by all applicable statutes, regulations, policies, plans and Activity-Based Funding.

9.1.1.5 Avoided Conversion Projects

In addition to the information in Section 9.1.1.1, the following information must be provided for Avoided Conversion projects:

1. Documentation demonstrating the planned or completed dedicating of the land in the Project Area to continuous forest cover through a Qualified Conservation Easement or transfer to public ownership.
2. Documentation demonstrating that the type of anticipated land use conversion is legally permissible per the requirements of Section 3.1.1.3.
3. A description of how the Project Area was determined, following the requirements in Section 4.
4. A full copy of the appraisal that was prepared for the Project Area per the requirements of Section 3.2.1.3.
5. A description of the highest value alternative land use identified in the appraisal.
6. An estimate the rate of conversion and removal of onsite carbon stocks per the requirements in Section 6.3.1.
7. A comparison of the fair market value of the anticipated alternative land use for the Project Area with the value of the current forested land use, and the calculation of an appropriate uncertainty discount (following the requirements in Section 6.3.1).
8. Where the anticipated alternative land use is commercial, residential or agricultural use, indicate the maximum slope of the project area.
9. Where the anticipated alternative land use is mining, describe the extent of mineral resources existing in the Project Area.
10. Where the anticipated alternative land use is commercial, residential or recreational use, indicate:
    a. The proximity of the Project Area to metropolitan areas;
    b. The proximity of the Project Area to grocery and fuel services and accessibility of those services;
    c. Population growth (people per year) within 180 miles of the Project Area.

9.2 Offset Project Data Report

Project operators or authorized project designees must submit an Offset Project Data Report each year by April 1. The report must be based on a single calendar year, as stated in the Regulation. The listing information in Section 9.1.1 must be included in the initial Offset Project Data Report, and is subject to verifier review during the initial verification. All Offset Project Data Report must include the information in section 9.2.1.

9.2.1 Annual Reporting

An Offset Project Data Report must be prepared for each calendar year during the Project Life. Offset Project Data Reports must be provided to verification bodies whenever a Forest Project undergoes verification. Offset Project Data Reports must contain an annual update of the project's forest carbon inventory (Section 8.2). Each report must also contain the following information. Reforestation Projects, as qualified in Section 6.1, can defer the items that are marked with an asterisk until submitting the offset project data report that will undergo the second verification.

1. Project Name.
2. Project Contact Information, including name, phone number, address, and email address for:

   a. Offset Project Operator
   b. Authorized Project Designee (if applicable);
3. Reporting Period.
4. A statement as to whether the Forest Project and associated Project Lands have met and been in compliance with all local, state, or federal regulatory requirements during the reporting period. If not, a description an explanation of the non-compliance must be provided.
5. A statement as to whether all the information submitted for project Listing still accurate. If not provided updates to the relevant listing information.
6. An updated estimate of the reporting year's carbon stocks in all required carbon pools.
7. *The appropriate confidence deduction for the forest carbon inventory following the requirements and methods in Appendix A, Section A.4)
8. *An explanation of any decrease over any 10-year consecutive period in the standing live carbon pool.
9. Any changes in the status of the Forest Owner including, if applicable per Section 3.8.1, the acquisition of new forest landholdings.
10. A description of how the project meets (or will meet) the definition of "Natural Forest Management" (refer to Section 3.8.2), including progress on criteria that have not been fully met in previous years.
11. *An estimate of reporting-year harvest volumes and associated carbon in harvested wood products.
12. *Estimated mill efficiency, as determined following the method in Appendix C, Section C.2.
13. The baseline carbon stock estimates for all required carbon pools for the reporting year, as determined following the requirements in Section 6 and approved at the time of the project's registration.
14. An estimate of Secondary Effects, following calculation steps and/or factors provided in Section 6 and approved at the time of the project's registration.
15. The uncertainty discount for avoided conversion projects, as determined following the requirements of Section 6.3 and approved at project registration. (After the initial verification, the uncertainty discount does not change.)
16. A calculation of total net GHG reductions and removal enhancements (QR_y) for the year, following the requirements in Section 6.
17. If a reversal has occurred during the previous year, the report must provide a written description and explanation of the reversal, whether the reversal has been classified as intentional or unintentional, and the status of compensation for the reversal.
18. *The project's reversal risk rating, as determined following the requirements in Section 7 and Appendix D.
19. *A calculation of the project's Buffer Account contribution.

9.2.2 Additional Reporting for Verification Years

Forest Projects must be verified at least every six years. If verification is less frequent than annual, Offset Project Data Reports must include the following additional information on aggregated GHG emission reductions or removal enhancements since the last verification:

1. Annual estimates of carbon stocks for all required carbon pools reported during each year since the last verification.
2. Confidence deduction for the forest carbon inventory applied for each year since the last verification for the project, if applicable.

3. Baseline carbon stock estimates for all required carbon pools reported during each year since the last verification.
4. Estimate of Secondary Effects reported during each year since the last verification.
5. If a reversal has occurred during the previous six years, the report must provide a written description and explanation of the reversal, whether the reversal has been classified as intentional or unintentional, and the status of compensation for the reversal.
6. Calculation of the project's Buffer Account contribution for each year since the last verification.
7. Calculation of total net GHG reductions and removal enhancements (QR_y) reported for each calendar year since the last verification.

9.3 Reporting and Verification Cycle

Upon completion of a reporting period, the Offset Project Operator or Authorized Project Designee must annually submit an Offset Project Data Report by April 1 according to the schedule specified in the Regulation. Offset Project Data Reports must be verified (including a site visit) by an approved ARB verification body at least once every six years.

A Forest Project is considered automatically terminated (see Section 3.4) if the Offset Project Operator or Authorized Project Designee chooses not to report data and undergo verification at required intervals.

9.3.1 Reporting Period Duration and Cycle

A "reporting period" is a period of time for which an Offset Project Operator or Authorized Project Designee quantifies and reports GHG reductions and removals (i.e. the length of time covered by a Offset Project Data Report). The reporting period for Forest Projects must consist of a 12 month calendar year, with one exception:

1. A Forest Project's first reporting period (the reporting period that precedes initial verification) may be any length of time, lasting from the project commencement date to December 31 of the year prior to the initial verification.

All reporting periods after the first reporting period must consist of a12 month calendar year in duration. Reporting periods must be contiguous; there must be no gaps in reporting during the crediting period of a Forest Project once the first reporting period has commenced.

9.3.2 Verification Cycle

All Forest Projects must have the initial Offset Project Data Report verified within 12 months of being submitted for project listing. For any verification thereafter, projects must be verified according to the schedule specified in the Regulation. Up to 6 years of GHG reductions or removals may be verified through a single verification, which may cover multiple reporting periods.

9.3.2.1 Minimum Required Verification Schedule

Except as allowed for the second verification of Reforestation Projects, ARB requires that an ARB-accredited third-party verification body review and assess all reported data and information for a Forest Project and conduct a site visit at least once every six years. Verification is also required anytime new confidence deductions and/or reversal risk ratings are established.

For Reforestation Projects, the second verification may be deferred up to 12 years at the discretion of the Offset Project Operator or Authorized Project Designee.

9.3.3 Issuance and Vintage

Provisions for the issuance of Offset Credits are specified in Subarticle 13 of the Regulation.

Reforestation Projects for which an initial inventory is deferred are not eligible to receive Offset Credits until after the second verification. Vintages will be assigned to Offset Credits by calendar year.

For a Forest Project's first reporting period only, if the reporting period covers more than two years, Offset Credits will be assigned a vintage according to the timing of GHG reductions or removals as determined through past inventories and modeling of changes in carbon stocks over the reporting period. If the first reporting period is two years or less, then issued Offset Credits will be assigned vintages according to the proportion of the reporting period that falls within each calendar year.

10 Verification

10.1 Regulatory Verification Requirements

Offset Project Data Reports must be verified in accordance with the regulatory verification requirements in Subarticle 13. Offset Credits will only be issued by ARB for quantified GHG reductions or removal enhancements that have been verified in accordance with these provisions. Verifiers must assess whether the submitted Offset Project Data Report is free of offset material misstatement for each calendar year of reported data, and whether the Offset Project Data Report is in conformance with the requirements of Subarticle 13 and this Compliance Offset Protocol. Failure to conform to any requirements in this protocol or Subarticle 13, as applicable, will result in an adverse verification statement or a qualified positive verification statement.

10.2 Additional Verification Requirements

In addition to the offset project verification requirements in § 95977, verification of Offset Project Data Reports for Forest Projects must include:

During the initial verification:

1. A detailed review of all required Listing Information during the initial verification.

During every verification:

2. A detailed review of the forest carbon inventory, including:
    a. Inventory methodology and sampling design;
    b. Inventory update processes;
    c. Measurement of sample plots and sample plot locations;
    d. Lifetime and updating of sample plots, as applicable;
    e. Stratification methods, if applicable;
    f. Biomass equations and calculations;
    g. Incorporation of growth and harvest modeling and data;
    h. Documentation of inventory methods and procedures, including procedures for data quality assurance and quality control.
3. Identification and re-measurement of a selection of sample plots, along with a comparison with inventory data to have reasonable assurance that sample plots are measured accurately. A minimum of 8 sample plots or 5% of the total sample plots used to develop the forest carbon inventory, whichever is greater, must be measured by the verification body. A paired t-test must be conducted to determine whether the verifier sample plot measurements are within the same population as the inventory submitted by the Offset Project Operator or Authorized Project Designee to a reasonable degree of confidence.
4. Application of appropriate confidence deductions, if applicable.
5. Review reversal risk rating calculation.
6. Review of conformance with natural forest management and sustainable harvesting requirements.
7. If verification is less frequently than annual, separately review and evaluate each calendar year of reported data specified in Section 9.2.2.

a. Each calendar year of quantified GHG reductions or removal enhancements (QR_y) is separately evaluated for offset material misstatement.

Each verification team must include at least one Professional Forester that takes in active role in reviewing the forest carbon inventory program and conducting the site visit.

11 Glossary of Terms

Above-Ground Live Biomass	The total mass of biomass in live trees including the stem, branches, and leaves or needles, brush and other woody live plants above ground.
Activity-Based Funding	The budget line items that are dedicated to agency accomplishments in vegetation management, including pre-commercial thinning, commercial thinning, harvest, hazard tree removal, hazardous fuel reductions, and other management activities designed to achieve forest sustainability health objectives.
Additional	Additional is defined in the Regulation. Under this protocol, GHG reductions or removals from Forest Projects are demonstrated to be addition when they pass a legal requirements test and a performance test, as described in Section 3.1, and by achieving GHG reductions and removals quantified against an approved baseline, determined according to the requirements in Section 6.
Allometric Equation	An equation that utilizes the genotypical relationship among tree components to estimate characteristics of one tree component from another. Allometric equations allow the below ground root volume to be estimated using the above-ground bole volume.
Assessment Area	A distinct forest community within geographically identified ecoregions that consists of common regulatory and political boundaries that affect forest management. The size of an Assessment Area is determined by efforts to achieve optimal statistical confidence across multiple scales using U.S. Forest Service Forest Inventory and Analysis Program (FIA) plots for biomass. Maps of the Assessment Areas and the associated data may be found on ARB's website.
Avoided Conversion Project	A type of Forest Project consisting of specific actions that prevent the conversion of privately owned forestland to a non-forest land use by dedicating the land to continuous forest cover through a conservation easement or transfer to public ownership.
Baseline	'Baseline' means 'Project Baseline' as defined in the Regulation. A baseline is a conservative estimate of business-as-usual GHG emission reductions or removals for the offset project's

	GHG emission sources, sinks and reservoirs within the offset project boundary. For the purposes of this protocol, a project's baseline must be estimated following standard procedures in Section 6.
Best Management Practices	Management practices determined by a state or designated planning agency to be the most effective and practicable means (including technological, economic, and institutional considerations) of controlling point and nonpoint source pollutants at levels compatible with environmental quality goals.
Biological Emissions	For the purposes of the Forest Offset Protocol, biological emissions are GHG emissions that are released directly from forest biomass, both live and dead, including forest soils. For Forest Projects, biological emissions are deemed to occur when the reported tonnage of onsite carbon stocks, relative to baseline levels, declines from one year to the next.
Biomass	Biomass is defined in the regulation.
Bole	A trunk or main stem of a tree.
Broadcast Fertilization	A fertilizer application technique where fertilizer is spread across the soil surface.
Business As Usual Scenario	Business As Usual Scenario is defined in the Regulation as the set of conditions, reasonably expected to occur within the Offset Project Boundary in the absence of the financial incentives provided by offset credits, taking into account all current laws and regulations, as well as current economic and technological trends. Methodologies for determining these conditions – and/or for approximating carbon stock levels that would have resulted from these conditions – are provided in Section 6 of this protocol for each type of Forest Project.
Carbon Pool	A greenhouse gas reservoir
Common Practice	The average stocks of the standing live carbon pool from within the Forest Project's Assessment Area, derived from FIA plots on all private lands within the defined Assessment Area.
Compliance Instrument	Compliance Instrument is defined in the Regulation as an allowance, offset credit or sector-based credit. Each compliance instrument can be used to fulfill a compliance obligation

	equivalent to up to one metric ton of CO2e.
Even-Aged Management	Management where the trees in individual forest stands have only small differences in their ages (a single age class). By convention, the spread of ages does not differ by more than 20 percent of the intended rotation.
FIA	USDA Forest Service Forest Inventory and Analysis program. FIA is managed by the Research and Development organization within the USDA Forest Service in cooperation with State and Private Forestry and National Forest Systems. FIA has been in operation under various names (Forest Survey, Forest Inventory and Analysis) for 70 years.
Forest Buffer Account	Forest Buffer Account is defined the Regulation as a holding account for forest offset credits administered by ARB . It is used as a general insurance mechanism against unintentional reversals for all forest offset projects listed under a Compliance Offset Protocol.
Forest Management	The commercial or noncommercial growing and harvesting of forests.
Forest Owner	A Forest Owner is defined in the Regulation as the owner of any interest in the property involved in a forest offset project, but does not include the holder of a conservation easement. Generally, a Forest Owner is the owner in fee of the property involved in a forest offset project. In some cases, one entity may be the owner in fee while another entity may have an interest in the trees or the timber on the property, in which case all entities or individuals with interest in the property are collectively considered the Forest Owners. All Forest Owner(s) are ultimately responsible for all commitments associated with a forest offset project.
Forest Project	A planned set of activities designed to increase removals of CO_2 from the atmosphere, or reduce or prevent emissions of CO_2 to the atmosphere, through increasing and/or conserving forest carbon stocks.
Forestland	Land that supports, or can support, at least 10 percent tree canopy cover and that allows for management of one or more forest resources, including timber, fish and wildlife, biodiversity, water quality, recreation, aesthetics and other public benefits.

Greenhouse Gases (GHG)	Carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_20), sulfur hexafluoride (SF_6), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), hydrocarbons, and other fluorinated greenhouse gases as defined in the Regulation.
Greenhouse Gas (GHG) Emissions Source	Greenhouse Gas Emissions Source or GHG Source as defined in the Regulation means, in the context of offset credits, any type of emitting activity that releases greenhouse gases into the atmosphere.
Greenhouse Gas (GHG) Reduction	GHG Reduction as defined in the Regulation means a calculated decrease in GHG emissions relative to a project baseline over a specified period of time.
Greenhouse Gas (GHG) Removal	GHG Removal as defined in the Regulation means the calculated total mass of a GHG removed, relative to a project baseline, from the atmosphere over a specified period of time.
GHG Removal Enhancement	GHG removal enhancement is defined in the Regulation as a calculated increase in GHG removals relative to a project baseline. In forest projects, GHG removal enhancements are calculated as gains in carbon stocks over time relative to a Forest Project's baseline
Greenhouse Gas (GHG) Reservoir	Greenhouse Gas Reservoir is defined in the Regulation as a physical unit or component of the biosphere, geosphere, or hydrosphere with the capability to store, accumulate, or release a GHG removed from the atmosphere by a GHG sink or a GHG captured from a GHG source. In the case of forests, GHG reservoirs may include above-ground or below-ground biomass or harvested wood products, among others.
Greenhouse Gas (GHG) Sink	Greenhouse Gas Sink or GHG Sink as defined in the Regulation means a physical unit or process that removes a GHG from the atmosphere.
Improved Forest Management Project	A type of Forest Project involving management activities that increase carbon stocks on forested land relative to baseline levels of carbon stocks.
Intentional Reversal	Intentional Reversal as defined in the Regulation means any reversal caused by a Forest Owner's negligence, gross negligence, or willful intent, including harvesting, development, and harm to the area within the Project Area.
Listed	A Forest Project is considered "listed" when an the Offset Project Operator or Authorized Project Designee is registered with ARB or an approved

	offset project registry, submits all required documentation for project listing in the regulation and this protocol, and the project has been approved by ARB or an approved offset project registry for listing.
Litter	Any piece(s) of dead woody material from a tree, e.g. dead boles, limbs, and large root masses, on the ground in forest stands that is smaller than material identified as lying dead wood.
Lying Dead Wood	Any piece(s) of dead woody material from a tree, e.g. dead boles, limbs, and large root masses, on the ground in forest stands. Lying dead wood is all dead tree material with a minimum average diameter of 5" and a minimum length of 8'. Anything not meeting the measurement criteria for lying dead wood will be considered litter. Stumps are not considered lying dead wood.
Metric ton (MT) or "ton"	A common international measurement for the quantity of GHG emissions, equivalent to about 2204.6 pounds or 1.1023 short tons.
Native Forest	For the purposes of this protocol native forests shall be defined as those occurring naturally in an area, as neither a direct nor indirect consequence of human activity post-dating European settlement.
Natural Forest Management	Forest management practices that promote and maintain native forests comprised of multiple ages and mixed native species at multiple landscape scales. The application of this definition, its principles, detailed definition, and implementation are discussed further in the Section 3.8.2.
Non-Forest Cover	Land with a tree canopy cover of less than 10 percent.
Non-Forest Land Use	An area managed for residential, commercial, or agricultural uses other than for the production of timber and other forest products, or for the maintenance of woody vegetation for such indirect benefits as protection of catchment areas, wildlife habitat, or recreation.
Non-Harvest Disturbance	Reduction in forest cover that is not a direct result of harvest, such as wildfire and insect disturbances.
Offset Credit	Offset credit is defined in the Regulation, and means a tradable compliance instrument issued or approved by ARB that represents a GHG reduction or removal enhancement of one metric

	ton of CO2e. The GHG reduction or GHG removal enhancement must be real, additional, quantifiable, permanent, verifiable and enforceable.
Offset Project Boundary	Offset Project Boundary as in the Regulation is defined by and includes all GHG emission sources, sinks, and reservoirs that are affected by an offset project and under control of the offset project operator. GHG sources, sinks or reservoirs not under control of the offset project operator are not included in the offset project boundary. Under this protocol, the offset project boundary is defined for each project type in Section 5. All GHG emission sources, sinks, and reservoirs within the offset project boundary must be accounted for in quantifying a Forest Project's GHG reductions and removals (Section 6).
Offset Project Data Report	Offset Project Data Report is defined in the Regulation as the report prepared by an Offset Project Operator or Authorized Project Designee each year that provides the information and documentation required by the regulation and this compliance offset protocol.
Onsite Carbon Stocks	Carbon Stock as defined in the Regulation means "the quantity of carbon contained in an identified GHG reservoir." For forest projects onsite carbon stocks include the carbon stocks in the required carbon pools indicated in Table A.1 within the Project Area.
Permanent	Permanent, as defined in the Regulation means either that GHG reductions or GHG removal enhancements are not reversible, or when GHG reductions or GHG removal enhancements may be reversible, that mechanisms are in place to replace any reversed GHG emission reductions or GHG removal enhancements to ensure that all credited reductions endure for a period that is comparable to the atmospheric lifetime of an anthropogenic CO2 emission. For Forest Projects, this requirement is met by requiring that the carbon associated with credited GHG reductions and removals remains stored for at least 100 years.
Primary Effect	The Forest Project's intended changes in carbon stocks, GHG emissions, or GHG removals.
Professional Forester	A professional engaged in the science and

	profession of forestry. For forest projects that occur in a jurisdiction that has professional forester licensing laws and regulations, a Professional Forester must be credentialed in that jurisdiction. Where a jurisdiction does not have a professional forester law or regulation, then a Professional Forester is defined as either having the Certified Forester credentials managed by the Society of American Foresters, or other valid professional forester license or credential approved by a government agency in a different jurisdiction.
Project Area	The area inscribed by the geographic boundaries of a Forest Project, as defined following the requirements in Section 4 of this protocol. Also, the property associated with this area.
Project Life	Refers to the duration of a Forest Project and its associated monitoring and verification activities, as defined in Section 3.4.
Public Lands	Lands that are owned by a public governmental body such as a municipality, county, state, or country.
Qualified Conservation Easement	A qualified conservation easement must explicitly refer to the requirements of the regulation and this protocol and apply to current and all subsequent Forest Owners for the full duration of the Forest Project's minimum time commitment, as defined in Section 3.4 of this protocol.
Reforestation Project	A type of Forest Project involving the restoration of tree cover on land that currently has no, or minimal, tree cover.
Retire	To retire a compliance instrument, as defined in the Regulation, means that the serial number for a compliance instrument is registered into the Retirement Compliance Account. Compliance instruments registered into this account cannot be used for further compliance.
Reversal	A reversal as defined in the Regulation means a GHG emission reduction or GHG removal enhancement, for which ARB has issued an offset credit, that is subsequently released or emitted back into the atmosphere due to any intentional or unintentional circumstance. Under this protocol, a reversal is deemed to have occurred if the quantified GHG reductions and removals in a given year are negative and offset credits were issued to the Forest Project in any previous year, regardless of the cause of the

	decrease.
Secondary Effects	Unintended changes in carbon stocks, GHG emissions, or GHG removals caused by the Forest Project.
Sequestration	Sequestration is defined in the Regulation as the removal and storage of carbon from the atmosphere in GHG sinks or GHG reservoirs through physical or biological processes.
Significant Disturbance	Any natural impact that results in a loss of least 20 percent of the above-ground live biomass that is not the result of intentional or grossly negligent acts of the Forest Owner.
Standing Dead Carbon Stocks	The carbon in standing dead trees. Standing dead trees include the stem, branches, roots, or section thereof, regardless of species, with minimum diameter (breast height) of five inches and a minimum height of 15 feet. Stumps are not considered standing dead stocks.
Standing Live Carbon Stocks	The carbon in the live tree biomass. Live trees include the stem, branches, roots, and leaves or needles of all live biomass, regardless of species, with a minimum diameter (breast height) of five inches and a minimum height of 15 feet.
Stocks (or Carbon Stocks)	The quantity of carbon contained in identified GHG reservoir (or carbon pool).
Submitted	A Forest Project is "submitted" when all of the appropriate forms have been uploaded and submitted.
Tree	A woody perennial plant, typically large and with a well-defined stem or stems carrying a more or less definite crown with the capacity to attain a minimum diameter at breast height of 5 inches and a minimum height of 15 feet with no branches within 3 feet from the ground at maturity.
Unintentional Reversal	An unintentional reversal as defined in the Regulation is any reversal not due to the Forest Owner's negligence, gross negligence or willful intent, including wildfires or disease that are not the result of the Forest Owner's negligence, gross negligence or willful intent.
Uneven-Aged Management	Management that leads to forest stand conditions where the trees differ markedly in their ages, with trees of three or more distinct age classes either mixed or in small groups.

Appendix A Developing an Inventory of Forest Project Carbon Stocks

Quantification Methodology

This appendix provides requirements for quantifying a Forest Project's forest carbon stocks. It explains how to identify the required forest carbon pools measured in a Forest Project, as well as the steps necessary for quantifying the existing carbon stocks in the selected pools within the Project Area. Carbon inventory information serves two purposes:

1. It is used as the basis for modeling and estimating carbon stocks in a project's baseline (following the requirements of Section 6).
2. It is used to quantify actual carbon stocks during the course of a project.

This appendix explains the essential steps and requirements for completing a carbon inventory for all required onsite carbon pools associated with a Forest Project.

A.1 Provide Background Information on Forest Area

To begin the inventory process, develop a general description of the activities and land use patterns that influence carbon stocks in the Project Area. This information will help inform the initial design of the forest inventory, as well as the estimations of carbon stocks. This information will be reviewed during verification.

At the time the Forest Project is submitted for Listing, the following information must be provided in map form (per Section 4), with the following information:

- Public and private roads
- Towns
- Major watercourses (4th order or greater)
- Topography
- Townships, ranges, and sections or latitude and longitude

Additionally the following information about the Project Area must be provided in narrative form, with maps optional:

- Existing land cover and land use
- Forest vegetation types and descriptions (including forest species identification, proportions, and trends in project area)
- Site classes
- Land pressures and climate zone/classification
- Historical land uses, current zoning, and projected land use within project area and surrounding areas
- Major watercourses, water bodies and watershed description

A.2 Measure Carbon Pools in the Project Area

Forest carbon pools are broadly grouped into the following categories:

1. Living biomass
2. Onsite dead biomass
3. Soil

Values for some of these categories of carbon will be determined through direct sampling. Table A.1 indicates the categories with their associated carbon pools and identifies which pools must

be quantified for all projects versus those are excluded depending on the project. It also shows how the value for the pool is determined.

Table A.1. Requirements of carbon pool categories and determination of value for pool

Category	Carbon Pool	Improved Forest Management	Reforestation	Avoided Conversion	Determination of Value
Living biomass	Standing Live	Required	Required*	Required	Sampled in Project
	Shrubs and Herbaceous Understory	Excluded	Required	Excluded	Sampled in Project
Onsite dead biomass	Standing Dead	Required	Required	Required	Sampled in Project
Soil	Soil**	Required/ Excluded**	Required/ Excluded**	Required/ Excluded**	Sampled in project

* Pre-existing trees must be distinguished from planted trees. Since pre-existing and new trees are easy to distinguish for several decades after tree planting, pre-existing trees do not need to be inventoried until the project first seeks verification of GHG reductions and removals (subsequent to the project's initial site-visit verification and registration).
** Soil carbon is not anticipated to change significantly as a result of most Forest Project activities. Soil carbon must be included in the inventory, however, if any of the following activities occur:

- Site preparation activities involve deep ripping, furrowing, or plowing where soil disturbance exceeds 25 percent of the Project Area, or
- Mechanical site preparation activities are not conducted on contours.

A.3 Developing Onsite Forest Carbon Inventories

To develop estimates of carbon stocks in the carbon pools identified in Table A.1, a forest inventory must first be conducted. Standard forest inventories require the establishment of sample plots and provide inventory estimates in terms of cubic or board foot volume. These measurements are based on the species, trunk or bole diameter, form and height of the tree.

Each Offset Project Operator must develop and document a forest carbon inventory methodology. The inventory method must be capable of quantifying carbon stocks for required carbon pools to a high degree of accuracy. A complete inventory methodology must include:

1. A description of the Offset Project Boundary, including a list of all carbon pools included in the Offset Project Boundary.
2. For each carbon pool, include a detailed description of the inventory sampling methodology used to quantify that carbon pool, with references clearly documented. This documentation must include:
    a. Standard procedures for the collecting of field measurements. These procedures must be detailed enough so that any qualified forester would be able to accurately repeat the previous measurements. Must include a description of the types of sample plots, location of plots, and frequency for updating or replacing sample plots as well as the forest carbon inventory as a whole;
    b. Standard procedures for where and how to measure parameters used in biomass calculations such as dbh and height (including for irregular trees), how to classify

dead wood, and for any other aspects of sampling where a consistent method needs to be documented; and

c. Stratification rules (pre and post sampling), if applicable, that include a map of vegetation strata, results of stratification (area by strata), tools for application (such as GIS, aerial photos), and a discussion of how boundaries were determined.

3. Documentation of all analytic methods and biomass equations used to translate field measurements into volume or biomass carbon estimates;
4. A documented quality assurance / quality control (QA/QC) plan including procedures for internal review to ensure that standard operating procedures are being followed. The QA/QC plan must include procedures for assessing and ensuring the quality of collection, transfer and archiving of field data; procedures for data entry and analysis, and data maintenance and archiving; and any other relevant procedures to ensure quality and consistency in the collection and maintenance of data used to compile the offset project data reports.
5. Description of data management systems and processes, including the collection, storage and analysis of inventory related data analytical methods to translate field measurements into volume and/or biomass estimates.
6. A change log documenting any changes in the inventory methods or equations used to calculate carbon stocks.
7. Standard procedures for updating the forest carbon inventory. Must include documented procedures to account for:
    a. Harvest;
    b. Growth;
    c. Disturbance;
    d. Incorporating new inventory and plot data, and retiring older sample plots;
    e. Modeling, as allowed under Appendix B; and
    f. Application of appropriate confidence deduction.

Inventory methods and sampling procedures, once established, must be consistent over the life of the project. Any changes to inventory methods or calculations must be documented and justified in the change log.

Allometric Equations and Biomass/Carbon Mass Estimates

The equations in this appendix and in Forest Offset Protocol Resources on ARB's webpage must be used for biomass and carbon mass estimations using the bole diameter and total height for live trees and sound standing dead trees. Estimates of standing dead tree (for non-sound trees) biomass must be computed in terms of cubic volume and subsequently converted to biomass/carbon mass estimates.

Sample Plots

Any plot data used for deriving the forest carbon inventory estimates must have been sampled within the last 12 years. The scheduling of plot sampling may occur in one time period or be distributed over several time periods. Either approach is acceptable so long as an inventory of the entire Project Area (its required carbon pools and corresponding sample plots) is completed within 12-year intervals.

Steps for Developing a Complete Forest Carbon Inventory

The steps that follow provide more detail on establishing and maintaining a complete inventory and estimating carbon stocks. Results must be summarized in a table when submitting required data in an Offset Project Data Report (see Section 9).

Step 1 – Developing Inventory Methodology and Sample Plots

The Offset Project Operator or Authorized Project Designee must develop and describe a methodology to sample for biomass or volume of all required carbon pools. If a pre-existing forest inventory is used to develop a forest carbon inventory, all steps here must be followed to ensure the existing inventory meets the requirements of this protocol.

Sampling methodology and measurement standards should be consistent throughout the duration of the Forest Project. If new methodologies are adopted, they must achieve an equal or greater accuracy relative to the original sampling design. All sampling methodologies and measurement standards must be statistically sound and must be approved during verification.

Stratification is not required, but it may simplify verification. Temporary flagging of plot center, as is customary to allow for check cruising, is required to ensure ongoing inventory quality and allow for verifiers to visit plots when verifying inventory procedures. If permanent plots are used, which are statistically efficient for stock change estimates, permanent plot monumenting must be sufficient for relocation. Plot centers should be referenced on maps, preferably with GPS coordinates. The methodologies utilized must be documented and made available for verification and public review. The design of the sampling methodology and measurement standards must incorporate the requirements in the following table.

Table A.2. Minimum required sampling criteria for estimated pools

Carbon Pool	Name of Requirement	Description of Requirement
Standing Live Trees (above-ground portion)	Diameter (breast height) Measurements	The stated minimum diameter in the methodology must not be greater than 5 inches (12.7 cm).
	Measurement Tools	Description of tools used for height measurement, diameter measurement, and plot measurement.
	Measurement Standards	The methodology shall include a set of standards for tree and plot size measurements.
	Plot Layout	A description of plot layout.
	Merchantability of Trees	The methodology shall include all trees regardless of current merchantability to be included in the sampling design.
	Allometric Equation used for Estimating Biomass	The methodology must include a description of the allometric equation used to estimate the whole tree biomass (bole, branches, and leaves) from bole diameter measurements. The use of functions other than those provided in the protocol will need to be approved by ARB and the verification body.
Standing Live Trees (below-ground portion)	Plot-level Allometric Equation used for Estimating Biomass	Apply model (Cairns, Brown, Helmer, & Baumgardner, 1997) to estimate below-ground biomass density. This model equation is based on above-ground biomass density in tons per hectare. The use of a function other than that provided in the protocol will need to be approved.
Herbaceous Understory	Sampling Methodology	The sampling methodology prepared by Brown, Shoch, Pearson, & Delaney (2004). Alternative methodologies need to be reviewed and approved by ARB and the verification body.
Standing Dead Trees	Diameter (breast height) and top Diameter Measurements	The stated minimum breast height diameter in the methodology must not be greater than 5 inches. The minimum height of standing dead trees is 15'. Include a description of how top diameter is derived.
	Measurement Tools	Description of tools used for height, diameter and plot measurement.
	Measurement Standards	The methodology shall include a set of standards for height and diameter measurements.
	Plot Layout	A description of plot layout (may be the same layout as for live tree biomass).
	Merchantability of Trees	The methodology shall include all trees regardless of current merchantability to be including in the sampling design.

Step 2 – Estimating Carbon in Live Trees from Sample Plots

Standing live tree carbon estimates are required for all projects. The standing live tree estimate includes carbon in all portions of the tree, including the bole, stump, bark, branches, leaves, and roots. The Offset Project Operator or Authorized Project Designee is responsible for determining appropriate methodologies for sampling to determine standing live tree carbon stocks. The estimate of above-ground live tree biomass must be combined with the estimates of biomass from other carbon pools to determine a mean estimate of the included pools derived from sampling, along with a summary that describes the statistical confidence of the estimate. Biomass estimates are converted to carbon estimates as described below.

The equations in Table A.3 are provided for a few common California species for estimating tree biomass from diameter (DBH) and total height (HT) measurements. This list does not contain all species that may be encountered in a Forest Project. Other approved biomass equations will be available in Forest Offset Protocol Resources on ARB's website.

For the equations below, diameter measurements are in inches and height measurements are in feet. The bole total volume (VOL) is calculated first and then multiplied by the wood density value for each species. This result is divided by 2.204622 to convert from pounds to kilograms. Conifer species have separate functions for bole, live crown, and bark biomass. Some hardwood species have volume functions that include these elements and therefore only one equation is used. The appropriate volume function for each species is cited in the following references: Means, Hansen; Koerper, Alaback, & Klopsch (1994) and Waddell & Hiserote (2005).

Table A.3. Sample of the Equations for Tree Species Biomass Estimates

Species	Bole Biomass (kg)	Bark Biomass (kg)	Live Crown Biomass (kg)
Douglas-fir	(VOL x 28.70) / 2.204622	Exp(-4.3103+2.43 x ln(DBH x 2.54))	Exp(-3.6941+2.1382 x ln(DBH x 2.54))
Ponderosa pine	(VOL x 23.71) / 2.204622	Exp(-3.6263+1.34077 x ln(DBH x 2.54)+ 0.8567 x ln(HT*0.3048))	Exp(-4.1068+1.5177 x ln(DBH x 2.54)+ 1.0424 x ln(HT*0.3048))
Coast redwood	(VOL x 21.22) / 2.204622	Exp(7.189689+1.58375 x ln(DBH x 2.54))/1000	0.199+0.00381 x (DBH x 2.54)^2 x (HT x 0.3048)
Tanoak	(VOL x 36.19) / 2.204622		
*Tanoak biomass is in one equation because it includes the bole, bark and crown volumes.			

The derived estimate of biomass must be multiplied by 0.5 to calculate the mass (kg) in carbon. This product must be multiplied by 0.001 tons/kg to convert the mass to metric tons of carbon.

Because of the difficulties associated with measuring the below-ground carbon component of trees, the estimation of this component of tree carbon through the use of a regression equation (Cairns, Brown, Helmer, & Baumgardner, 1997) is allowed. This equation provides a practical and cost-effective approach that estimates below-ground biomass of standing live trees using the sampling-based calculation of above-ground biomass of standing live trees only:

$$BBD = \exp(-0.7747 + 0.8836 \times \ln(ABD))$$

Where:

BBD = below-ground biomass density of standing live trees in tons per hectare
ABD = above-ground biomass density of standing live trees in tons per hectare

This equation must be applied at the plot level, after estimates of above-ground biomass have been calculated as described above.

Example A.1. Quantification Example (Part III – Tree Biomass)

The chart below displays summary data for tree biomass for the first plot in Strata 1.

Tree Biomass								
1	2	3	4	5	6	7	8	9
Plot	Tree Number	Species	DBH (cm)	Total Height (m)	Status	Biomass (kg)	Weight (Expansion per Hectare)	Biomass (kg per Hectare)
1	1	Redwood	65	32	L	2,560	21	53,768
1	2	Douglas-fir	65	29	L	2,007	21	42,152
1	3	Tanoak	28	14	L	280	112	31,402
1	4	Redwood	68	30	L	2,677	19	50,858
1	5	Redwood	76	27	L	3,086	15	46,287
1	6	Douglas-fir	65	34	L	2,310	21	48,501
1	7	Tanoak	42	17	L	729	50	36,442
1	8	Tanoak	46	18	L	914	41	37,464
							Total	346,874

The plot in this example was measured using a 30 square foot basal area factor prism. The plot number is entered in column 1. All 'in' trees (trees on the plot) are measured and input consecutively starting at North and proceeding clockwise (this facilitates check cruising, quality control). Each tree is numbered (column 2), the species documented (column 3), the DBH measurements entered as centimeters in column 4, and the total height entered as meters in column 5.

The status of the tree goes in column 6. The status codes are shown below.

Status Codes	Description
L	Live
D1	Dead, with large and small branches and twigs
D2	Dead, with large and small branches and no twigs
D3	Dead, with large branches only
D4	Dead, with no branches

Only live trees are input into the Tree Biomass worksheet. The biomass for each tree is determined (column 7) using the volume, mass, and allometric equations provided in Step 2. The basal area factor and each tree's diameter (breast height) are used to determine the expansion factor, or weight, of each tree (column 8). The expansion factor is multiplied by each tree's biomass to portray the biomass estimate of each tree on a per hectare basis (column 9). Each tree's expanded biomass is summed to calculate the estimated total biomass in trees on plot 1. Plot 1's estimate of above-ground tree biomass in Strata 1 is calculated to be 346,874 kilograms per hectare. Based on this estimate, an estimate of below-ground biomass on a per hectare basis can be calculated using the equation above. The estimate of below-ground biomass is 80,918 kilograms per hectare. The combined estimate of biomass in Plot 1 is 427,792 kilograms per hectare.

Step 3 – Estimating Carbon Standing Dead Tree Carbon from Sample Plots

An inventory of carbon stocks in standing dead tree carbon is required for all Forest Projects. The Offset Project Operator or Authorized Project Designee must provide a sampling methodology for standing dead tree carbon as part of an overall sampling strategy (discussed in Step 1). The estimate of standing dead tree carbon for highly decayed trees (broken tops, missing branches, etc.), must be calculated first volumetrically and subsequently converted to

biomass and carbon tons. Sound dead trees can be computed using the equations provided for live trees in Step 2. The equations used in Step 2 provide an estimate of biomass in kilograms. The estimate must be converted to metric tons of carbon by multiplying the result by 0.001 tons/kg.

For those trees where volume is computed, the volume will need to be converted to biomass density by applying conversion factors based on a sub-sample of material that represents the species groups and decomposition classes. The methodology developed for standing dead biomass must include a description of the calculation techniques used to determine biomass density by decomposition classes and species groups. The estimate of biomass density must be computed in terms of metric tons of carbon on a per hectare basis. A description of a methodology to generate the density factors can be found in the Brown, Shoch, Pearson, & Delaney (2004) document mentioned in Table A.2. Alternatively, the density factors by decay class from Harmon et al (2008) may be used to estimate density in standing dead trees.

Step 4– Estimate Carbon in Shrubs and Herbaceous Understory from Sample Plots

Any methodology developed for measuring carbon in shrubs must be reviewed during verification. Inventory estimates for shrubs must be computed in terms of metric tons of carbon. The most applicable biomass estimation methods may be used, including photo series, the estimation functions from published papers, direct sampling, or combinations of approaches.

Step 5 – Estimate of Carbon Tons in Soil

Changes in total soil carbon are a challenge to measure over short timeframes, as this pool changes slowly and is usually dependent on the rate of biomass input relative to soil decomposition. The sampling methodology and protocols for deriving carbon estimates in soil must be developed as part of an overall sampling strategy (discussed in Step 2). Use the soil sampling methodology prepared by Brown, Shoch, Pearson, & Delaney (2004). Estimates must be computed in terms of metric tons of carbon.

Step 6 – Sum Carbon Pools

The metric tons of carbon in each carbon pool, as derived from the preceding steps, must be entered in the following table. For the purpose of quantifying GHG reductions and removals, all numbers must be converted to metric tons of CO_2-equivalent by multiplying by 3.664.

Table A.4. Worksheet for Summarizing Carbon Pools and Calculating Total Carbon

Carbon Pool	Gross Carbon Tons per Hectare	Gross CO_2-equivalent Tons per Hectare
Step 2 Live Trees	From sampling results of trees.	
Steps 3 Standing Dead Trees	From sampling results of standing dead biomass and lying dead biomass.	
Step 4 Shrubs and Herbaceous Understory	From sampling results of shrubs and herbaceous understory.	
Step 5 Soil	From sampling results of soil.	
Sum of CO_2-equivalent Tons from Required Pools		

A.4 Applying a Confidence Deduction

Any forest carbon inventory estimate will be subject to statistical uncertainty. Where statistical confidence is low, there is a higher risk of overestimating a project's actual carbon stocks and therefore a higher risk of over-quantifying GHG reductions and removals. To help ensure that estimates of GHG reductions and removals are conservative, a confidence deduction must be applied each year to the inventory of actual onsite carbon stocks. A confidence deduction is *not* applied to the forest carbon inventory when it is used to model baseline carbon stocks.

To determine the appropriate confidence deduction, perform the following:

1. Compute the standard error of the inventory estimate (based on the carbon in standing live and standing dead carbon pools).
2. Multiply the standard error by 1.645.
3. Divide the result in (2) by the total inventory estimate and multiply by 100. This establishes the sampling error (expressed as a percentage of the mean inventory estimate from field sampling) for a 90 percent confidence interval.
4. Consult Table A.5 to identify the percent confidence deduction that must be applied to the inventory estimate for the purpose of calculating GHG reductions and removals (i.e. variable CD_y in Equation 6.1 in Section 6).

Table A.5. Forest carbon inventory confidence deductions based on level of confidence in the estimate derived from field sampling.

Sampling Error (% of Inventory Estimate)	Confidence Deduction
0 to 5%	0%
5.1 to 19.9%	(Sampling Error – 5.0%) to the nearest 1/10th percentage
20% or greater	100%

The confidence deduction must be updated each time the project is subject to verification, but must remain unchanged between verifications. If increased sampling over time results in a lower confidence deduction at the time of verification, the lower deduction must be applied to inventory estimates in the most recent calendar year subject to verification at that time. Offset Credits may be issued in the most recent calendar year for any verified increase in quantified GHG reductions and removals associated with the new (lower) confidence deduction. Conversely, if a loss of qualified sampling plots results in a higher confidence deduction, this higher deduction is applied to the inventory estimates in the most recent calendar year subject to verification at that time. Any resulting decrease in quantified GHG reductions and removals from prior years as a result of the increased confidence deduction will be treated as an intentional reversal, and must be compensated for by retiring Compliance Instruments in accordance with Section 7.3.2.

Appendix B Modeling Carbon Stocks

Quantification Methodology

This protocol requires the use of certain empirical-based models to estimate the baseline carbon stocks and project stocks of selected carbon pools within the Project Area. These models may also be used to supplement assessments of actual changes in carbon stocks resulting from the Forest Project.

B.1 About Models and Their Eligibility for Use with Forest Projects

Empirical-based models are used for estimating existing values where direct sampling is not possible or cost-effective. They are also used to forecast the estimations derived from direct sampling into the future. Field measurements provide the basis for inferring value through the use of these models.

The models that simulate growth projections have two basic functions in the development and management of a forest project. Models project the results of direct sampling through simulated forest management activity. These models, often referred to as growth and yield simulation models, may project information regarding tree growth, harvesting, and mortality over time – values that must ultimately be converted into carbon in an additional step. Other models may combine steps and estimate tree growth and mortality, as well as changes in other carbon pools and conversions to carbon, to create estimated projections of carbon stocks over time.

Models are also used to assist in updating inventory plots so that the plots can represent a reporting year subsequent to their actual sample date. The model simulates the diameter and height increment of sampled trees for the length of time between their sampled date and the reporting year. The limit to the use of models for updating plot data is described in Appendix A.

The following growth models have been approved:

- CACTOS: California Conifer Timber Output Simulator
- CRYPTOS: Cooperative Redwood Yield and Timber Output Simulator
- FVS: Forest Vegetation Simulator
- SPS: Stand Projection System
- FPS: Forest Projection System
- FREIGHTS: Forest Resource Inventory, Growth, and Harvest Tracking System
- CRYPTOS Emulator
- FORESEE

Inventory plot data may be updated for estimating diameter and height growth by incorporating data obtained from sample plots, as in a stand table projection. To qualify for this method:

- The Project Area shall be stratified into even-age management and uneven-age management.
- Diameter increment shall be based on the average annual increment of a minimum of 20 samples of radial growth for diameter increment for each 8" DBH (diameter at breast height) class, beginning at 0 – 8" DBH for each management (even-age or uneven-age) type. The average annual increment shall be added for each year according to the plot's sample date.
- Height increment shall be based on regression curves for each management type (even-age or uneven-age) developed from height measurements from the same trees the

diameter increment data was obtained. The estimated height shall be determined using the regression estimators for the 'grown' diameters as described above.

Additional models will be allowed following approval of a state forestry authority (i.e. a state agency responsible for oversight of forests) who will acknowledge in writing that the model:

- Has been peer reviewed in a process that: 1) primarily involved reviewers with necessary technical expertise (e.g. modeling specialists and relevant fields of biology, forestry, ecology, etc.), and 2) was open and rigorous
- Is parameterized for the specific conditions of the Project Area
- Limits use to the scope for which the model was developed and evaluated
- Is clearly documented with respect to the scope of the model, assumptions, known limitations, embedded hypotheses, assessment of uncertainties, and sources for equations, data sets, factors or parameters, etc.
- Underwent a sensitivity analysis to assess model behavior for the range of parameters for which the model is applied
- Is reviewed at least every 10 years

B.2 Using models to forecast carbon stocks

The use of simulation models is required for estimating a Forest Project's baseline carbon stocks. Models may also be required to forecast actual carbon stocks expected under the Forest Project (e.g. in conjunction with determining expected harvesting volumes or in updating forest carbon inventories).

Inventory information from Appendix A must be incorporated into the simulation models to project carbon stocks over time. If a model has the ability to convert biomass to carbon, it must include all the carbon pools required by this protocol.

Projected baseline or actual carbon stocks must be portrayed in a graph depicting time in the x-axis and carbon tons in the y-axis. Baseline carbon stocks must be projected forward from the date of the Forest Project's initiation. The graph should be supported with written characterizations that explain any annual changes in baseline carbon stocks over time. These characterizations must be consistent with the baseline analysis required in Section 6.

B.3 Modeling Requirements

A modeling plan must be prepared that addresses all required forecasting or updating of baseline and actual carbon stocks for the Forest Project. The modeling plan shall contain the following elements:

1. A description of all silviculture methods modeled. The description of each silviculture method will include:
    a. A description of the trees retained (by species groups if appropriate) at harvest.
    b. The harvest frequency (years between harvests).
    c. Regeneration assumptions.
2. A list of all legal constraints that affect management activities on the Project Area. This list must identify and describe the constraint and discuss the silviculture methods that will be modeled to ensure the constraint is respected.
3. A description of the site indexes used for each species and an explanation of the source of the site index values used.
4. A description of the model used and an explanation of how the model was calibrated for local use, if applicable.

Modeling outputs must include:

1. Periodic harvest, inventory, and growth estimates for the entire Project Area presented as total carbon tons and carbon tons per acre.
2. Harvest yield streams on modeled stands, averaged by silviculture method and constraints, which must include the period over which the harvest occurred and the estimated volume of wood removed.

Appendix C Estimating Carbon in Wood Products

Quantification Methodology

Wood products may constitute a reservoir for storing carbon over the long term. Projects that increase wood product production can receive credit for the resulting incremental carbon storage. By the same token, projects that reduce wood product production must account for the incremental *reduction* in stored wood product carbon. As indicated in Section 7, GHG reductions and removals must be effectively "permanent," meaning that sequestered carbon associated with GHG reductions and removals must remain stored for at least 100 years. Wood product carbon is estimated by calculating the average amount of carbon that is likely to remain stored in wood products over a 100-year period.

The processes described here are adapted from the 1605(b) methodology (U.S. Department of Energy, 2007) for accounting for the long-term storage of wood products. Please see Smith, Heath, Skog, & Birdsey (2006) for a more detailed description since the 1605(b) procedure was adapted from this publication.

Because of the significant uncertainties associated with predicting wood product carbon storage over 100 years, the accounting requirements in this appendix are designed to err on the side of conservativeness. This means the calculations are designed to reduce the risk of overestimating the GHG reductions and removals achieved by a Forest Project. One of the largest sources of uncertainty is predicting the amount of wood product carbon likely to be stored in landfills. To accommodate this uncertainty, and ensure that Forest Project GHG reductions and removals are accounted for conservatively:

1. Landfill carbon storage is *excluded* from calculations of wood-product carbon in years where a Forest Project's actual harvesting volumes exceed estimated baseline harvesting volumes, as determined in Section 6.
2. Landfill carbon storage is *included* in calculations of wood-product carbon in years where a Forest Project's actual harvesting volumes are below estimated baseline harvesting volumes, as determined in Section 6.

Accounting for wood product carbon must be applied only to actual or baseline volumes of wood harvested from within the Project Area. Trees harvested outside of the Project Area are not part of the Forest Project and must be excluded from any calculations.

There are five steps required to determine carbon stored in wood products:

1. Determining the amount of carbon in harvested wood that is delivered to mills.
2. Accounting for mill efficiencies.
3. Estimating average carbon storage over 100 years in in-use wood products.
4. Estimating average carbon storage over 100 years in wood products in landfills (when applicable).
5. Summing the results to determine total average carbon storage over 100 years.

C.1 Determine the Amount of Carbon in Harvested Wood Delivered to Mills

The following steps must be followed to determine the amount of carbon in harvested wood:

1. Determine the amount of wood harvested (actual or baseline) that will be delivered to mills, by volume (cubic feet) or by green weight (lbs.), and by species for the current year (y). In all cases, harvested wood volumes and/or weights must exclude bark.

a. Baseline harvested wood volumes and species are derived from modeling a baseline harvesting scenario, following the requirements in Section 6.
b. Actual harvested wood volumes and species must be based on verified third-party scaling reports, where available. Where not available documentation must be provided to support the quantity of wood volume harvested.

2. If a volume measurement is used, multiply the cubic foot volume by the appropriate wood density factor in Table C.1 (for projects located in the Pacific Southwest) or from the USFS Wood Handbook (other regions).[8] This results in pounds of biomass with zero moisture content.
3. If a weight measurement is used, subtract the water weight based on the moisture content of the wood. This results in pounds of biomass with zero moisture content.
4. Sum the dry weights for each harvested species to get a total dry weight for all harvested wood.
5. Multiply this total value by 0.5 pounds of carbon/pound of wood to compute the total carbon weight.
6. Divide the total carbon weight by 2,204.6 pounds/metric ton to convert to metric tons of carbon. This value is used in the next step, accounting for mill efficiencies.

Table C.1. Specific gravity and Wood Density of green softwoods and hardwoods by forest type for the Pacific Southwest from Table 1.4.

Forest Type	Specific Gravity of Softwoods	Specific Gravity of Hardwoods	Wood Density of Softwoods (lbs/ft^3)	Wood Density of Hardwoods (lbs/ft^3)
Mixed conifer	0.394	0.521	24.59	32.51
Douglas-fir	0.429	0.483	26.77	30.14
Fir-spruce-hemlock	0.372	0.510	23.21	31.82
Ponderosa pine	0.380	0.510	23.71	31.82
Redwood	0.376	0.449	23.46	28.02

C.2 Account for Mill Efficiencies

Multiply the total carbon weight (metric tons of carbon) derived in C.1 by the mill efficiency identified for the project's Assessment Area in the Forest Offset Protocol Resources section of ARB's website. This is the total carbon transferred into wood products. The remainder of the harvested carbon is considered to be immediately emitted to the atmosphere for accounting purposes in this protocol.

C.3 Estimate the Average Carbon Storage Over 100 Years in In-Use Wood Products

The amount of carbon that will remain stored in in-use wood products for at least 100 years depends on the rate at which wood products either decay or are sent to landfills. Decay rates depend on the type of wood product that is produced. Thus, in order to account for the decomposition of harvested wood over time, a decay rate is applied to wood products according

[8] The Wood Handbook (USFS, 2010) contains specific gravities for tree species in other regions. Multiply the specific gravity by the density of water (62.43 lbs/ft^3) to get wood density.

to their product class. To approximate the climate benefits of carbon storage, this protocol accounts for the average amount of carbon stored over 100 years. Thus, decay rates for each wood product class have been converted into "average storage factors" in Table C.2, below.

To determine the average carbon storage in in-use wood products over 100 years, the first step is to determine what percentage of a Project Area's harvest will end up in each wood product class (Columns A-G in Table C.2). This must be done by either:

1. Obtaining a verified report from the mill(s) where the Project Area's logs are sold indicating the product categories the mill(s) sold for the year in question; or
2. If a verified report cannot be obtained, looking up default wood product classes for the project's Assessment Area, as given in the **Error! Reference source not found.**Forest Offset Protocol Resources section of ARB's website.

If breakdowns for wood product classes are not available from either of these sources, classify all wood products as "miscellaneous."

Once the breakdown of in-use wood product categories is determined, use the worksheet in Table C.2 to estimate the average amount of carbon stored in in-use wood products over 100 years:

1. Assign a percentage to each product class (columns A-G) according to mill data or default values for the project.
2. Multiply the total carbon transferred into wood products (determined in Section C.2) by the percentages in each column and insert the resulting values into boxes 3A through 3G.
3. Multiply the values in 3A-3G by the 100-year average storage factor and insert the results into boxes 4A through 4G.
4. Use Equation C.1 to calculate the average carbon stored in in-use wood products over 100 years (in units of CO_2-equivalent metric tons).

Equation C.1. Average Carbon Stored in In-Use Wood Products

$$WP_{in\text{-}use,\,y} = \sum(\text{Table C.2, Row 4}) \times 3.67$$

Where,

$WP_{in\text{-}use,\,y}$ = Average carbon stored in in-use wood products over 100 years from wood harvested in year y (actual or baseline)

Table C.2. Worksheet to Estimate Long-Term Carbon Storage In In-Use Wood Products

	A	B	C	D	E	F	G
Wood Product Class	Softwood Lumber	Hardwood lumber	Softwood Plywood	Oriented Strandboard	Non Structural Panels	Miscellaneous Products	Paper
% in each class	(X%)	(X%)	(X%)	(X%)	(X%)	(X%)	(X%)

Metric tons C in each class	(3A)	(3B)	(3C)	(3D)	(3E)	(3F)	(3G)
100-year average storage factor (in-use)	0.463	0.250	0.484	0.582	0.380	0.176	0.058
Average C stored in in-use wood products (metric tons)	(4A)	(4B)	(4C)	(4D)	(4E)	(4F)	(4G)

C.4 Estimate the Average Carbon Storage Over 100 Years for Wood Products in Landfills

Wood product carbon in landfills is only calculated for years in which a Forest Project's actual harvesting volumes are below estimated baseline harvesting levels, as determined in Section 6. To determine the appropriate value for average landfill carbon storage, perform the following steps:

Step 1 – Calculate the average carbon storage over 100 years for wood products in landfills

Use the worksheet in Table C.3 to estimate the average amount of wood product carbon stored in landfills over 100 years:

1. Assign a percentage to each product class (columns A-G) according to mill data or default values for the project (as determined in Section C.3).
2. Multiply the total carbon transferred into wood products (determined in Section C.2) by the percentages in each column and insert the resulting values into boxes 3A through 3G.
3. Multiply the values in 3A-3G by the 100-year average storage factor for landfill carbon and insert the results into boxes 4A through 4G.

Table C.3. Worksheet to Estimate Long-Term Carbon Storage in Wood Products in Landfills

	A	B	C	D	E	F	G
Wood Product Class	Softwood Lumber	Hardwood lumber	Softwood Plywood	Oriented Strandboard	Non Structural Panels	Miscellaneous Products	Paper
% in each class	(X%)	(X%)	(X%)	(X%)	(X%)	(X%)	(X%)
Metric tons C in each class	(3A)	(3B)	(3C)	(3D)	(3E)	(3F)	(3G)
100-year average storage factor (landfills)	0.298	0.414	0.287	0.233	0.344	0.454	0.178
Average C stored in landfills (metric tons)	(4A)	(4B)	(4C)	(4D)	(4E)	(4F)	(4G)

Step 2 – Determine the appropriate value to use for wood product carbon in landfills

Use Equation C.2. Average Wood Product Carbon Stored in Landfills to determine the appropriate value for the average wood product carbon stored in landfills over 100 years (in units of CO_2-equivalent metric tons).

Equation C.2. Average Wood Product Carbon Stored in Landfills

$$If \sum_{n=1}^{y-1} (AC_{hv,n} - BC_{hv,n}) < 0, then\ WP_{landfill,y} = \sum (Table\ C.3, Row\ 4) \times 3.67$$

$$If \sum_{n=1}^{y-1} (AC_{hv,n} - BC_{hv,n}) > 0, then\ WP_{landfill,y} = 0$$

Where,

$WP_{landfill, y}$ = Average carbon stored in wood products in landfills over 100 years from wood harvested in the current year/reporting period (actual or baseline)

$AC_{hv, n}$ = Actual amount of onsite carbon harvested in reporting period n (prior to delivery to a mill), expressed in CO_2-equivalent tons

$BC_{hv, n}$ = Estimated average baseline amount of onsite carbon harvested in reporting period n (prior to delivery to a mill), expressed in CO_2-equivalent tons

y = The current year or reporting period

C.5 Determine Total Average Carbon Storage in Wood Products Over 100 Years

The total average carbon storage in wood products over 100 years for a given harvest volume (as determined in Section C.1) must be calculated and reported as follows (Equation C.3). The value derived for WP_{total} must be used for actual and baseline wood product carbon estimates ($AC_{wp,y}$ or $BC_{wp,y}$ in Equation 6.1) as appropriate, following the in Section 6.

Equation C.3.

$$\mathbf{WP_{total,\,y} = WP_{in\text{-}use,\,y} + WP_{landfill,\,y}}$$

Where,

$WP_{total,\,y}$	=	Average carbon stored over 100 years from wood harvested in year y (actual or baseline)
$WP_{in\text{-}use,\,y}$	=	Average carbon stored in in-use wood products over 100 years from wood harvested in year y (actual or baseline)
$WP_{landfill,\,y}$	=	Average carbon stored in wood products in landfills over 100 years from wood harvested in year y (actual or baseline)

Appendix D Determination of a Forest Project's Reversal Risk Rating

A reversal risk rating must be determined for the Forest Project using the worksheets in this section. The worksheets are designed to identify and quantify the specific types of risks that may lead to a reversal, based on project-specific factors.

This risk assessment must be updated every time the project undergoes a verification site visit. Therefore, a project's risk profile and its assessment are dynamic. If estimated risk values and associated mitigation measures are updated as improvements in quantifying risks or changes in risks are determined, any adjustments to the risk ratings will affect only current and future year contributions to the Buffer Account.

Risks that may lead to reversals are classified into the categories identified in Table D.1.

Table D.1. Forest Project Risk Types

Risk Category	Risk Type	Description	How managed in this protocol
Financial	Financial Failure Leading to Bankruptcy	Financial failure can lead to bankruptcy and/or alternative management decisions to generate income that result in reversals through over-harvesting or conversion	Default Risk
Management	Illegal Harvesting	Loss of project stocks due to timber theft	Default by Area
	Conversion to Non-Forest Uses	Alternative land uses are exercised at project carbon expense	Default Risk
	Over-Harvesting	Exercising timber value at expense of project carbon	Default Risk
Social	Social Risks	Changing government policies, regulations, and general economic conditions	Default Risk
Natural Disturbance	Wildfire	Loss of project carbon through wildfire	Default Risk
	Disease/Insects	Loss of project carbon through disease and/or insects	Default Risk
	Other Episodic Catastrophic Events	Loss of project carbon from wind, snow and ice, or flooding events	Default Risk

D.1 Financial Risk

Financial failure of an organization resulting in bankruptcy can lead to dissolution of agreements and forest management activities to recover losses that result in reversals. Projects that employ a Qualified Conservation Easement, or that occur on public lands, have lower risk.

Table D.2. Financial Risk Identification

Applies to all projects		
Identification of Risk	**Contribution to Reversal Risk Rating**	
Default Financial Risk	**Forest Project not on public lands or without a Qualified Conservation Easement**	**Forest Project on public lands or with a Qualified Conservation Easement**
	5%	1%

D.2 Management Risk

Management failure is the risk of management activities that directly or indirectly could lead to a reversal. Projects that occur on public lands, or employ a Qualified Conservation Easement are exempt from this risk category.

Management Risk I – Illegal Removals of Forest Biomass

Illegal logging occurs when biomass is removed either by trespass or outside of a planned set of management activities that are controlled by regulation. Illegal logging is exacerbated by lack of controls and enforcement activities.

Table D.3. Risk of Illegal Removals of Forest Biomass

Applies to all projects	
Identification of Risk	**Contribution to Reversal Risk Rating**
United States Default Harvesting Risk	0%

Management Risk II – Conversion of Project Area to Alternative Land Uses

High values for development of housing and/or agriculture may compete with timber and carbon values and lead to a change in land use that affects carbon stocks. The risk of conversion of any Project Area to other non-forest uses is related to the probability of alternative uses, which are affected by many variables, including population growth, topography, proximity to provisions and metropolitan areas, availability of water and power, and quality of access to the Project Area.

Table D.4. Risk of Conversion to Alternative Land Use

Applies to all projects	
Identification of Risk	**Contribution to Reversal Risk Rating**
With Qualified Conservation Easement that explicitly encumbers all development rights	0%
Without Qualified Conservation Easement	2%

Management Risk III – Over-Harvesting

Favorable timber values, among other reasons, may motivate some project managers to realize timber values at the expense of managing carbon stocks for which Offset Credits have been issued. Additionally, reversals can occur as the result of harvest associated with fuels treatments.

Table D.5. Risk of Over-Harvesting

Applies to all projects	
Identification of Risk	**Contribution to Reversal Risk Rating**
With Qualified Conservation Easement that explicitly encumbers timber harvesting associated with project stocks	0%
Without Qualified Conservation Easement	2%

D.3 Social Risk

Social risks exist due to changing government policies, regulations, and general economic conditions. The risks of social or political actions leading to reversals are low, but could be significant.

Table D.6. Social Risk Identification

Applies to all projects	
Identification of Risk	**Contribution to Reversal Risk Rating**
United States Default Social Risk	2%

D.4 Natural Disturbance Risk

Natural disturbances can pose a significant risk to the permanence of the GHG reductions and removals. Natural disturbance risks are only partially controllable by management activities. Management activities that improve resiliency to wildfire, insects, and disease can reduce these

risks. Management activities that shift harvesting practices from live sequestering trees to trees that have succumbed to natural disturbances reduce or negate the reversal depending on the size and location of the disturbance.

Natural Disturbance Risk I – Wildfire

A wildfire has the potential to cause significant reversals, especially in certain carbon pools. These risks can be reduced by certain techniques including reducing surface fuel loads, removing ladder fuels, adding fuel breaks, and reducing stand density. However, these techniques cannot reduce emission risk to zero because all landowners will not undertake fuel treatments, nor can they prevent wildfire from occurring.

Table D.7. Natural Disturbance Risk I – Wildfire

Applies to all projects	
Identification of Risk	**Contribution to Reversal Risk Rating**
United States Default Fire Risk	4%
If fuel treatments have been implemented for the Project Area, reduce the value above by the appropriate Y% as indicated below.*	(4%) x Y%

* Depending on the level of fuel treatments the Y% is set as follows:
- high level of fuel treatments = 50%,
- medium level of fuel treatments = 66.3%,
- low level of fuel treatments = 82.6%,
- no fuel treatments = 100%.

Natural Disturbance Risk II - Disease or Insect Outbreak

A disease or insect outbreak has the potential to cause a reversal, especially in certain carbon pools.

Table D.8. Natural Disturbance Risk II – Disease or Insect Outbreak

Applies to all projects	
Identification of Risk	**Contribution to Reversal Risk Rating**
Default Risk Contribution from Disease or Insect Outbreak	3%

Natural Disturbance Risk III - Other Episodic Catastrophic Events

A major wind-throw event (hurricane, tornado, high wind event) has the potential to cause a reversal, especially in certain carbon pools.

Table D.9. Natural Disturbance Risk III – Other Episodic Catastrophic Events.

Applies to all projects	
Identification of Risk	**Contribution to Reversal Risk Rating**
Default Risk Contribution from Other Catastrophic Events	3%

D.5 Summarizing the Risk Analysis and Contribution to Buffer Account

Use table D.10 to summarize the Forest Project's reversal risk rating. As indicated above, projects that employ a Qualified Conservation Easement, or that occur on public lands, are exempt from certain risk categories. Such Qualified Conservation Easements must clearly identify the goals and objectives of the Forest Project according to the terms of this protocol.

Table D.10. Project Contribution to the Buffer Account Based on Risk.

Risk Category	**Contribution from Risk Descriptions Above**		
	Source	Forest Project without a Qualified Conservation Easement and/or Public Ownership	Forest Projets with a Qualified Conservation Easement and/or Public Ownership
Financial Failure	Default Risk -Remedies for reversals addressed in PIA	5%	1%
Illegal Forest Biomass Removal	Default Risk	0%	0%
Conversion	Default Risk - Remedies for reversals addressed in PIA	2%	0%
Over-Harvesting	Default Risk - Remedies for reversals addressed in PIA	2%	0%
Social	Default Risk	2%	2%
Wildfire	Calculated Risk from worksheet	X%	X%
Disease or Insect Outbreak	Calculated Risk from worksheet	3%	3%
Other Catastrophic Events	Calculated Risk from worksheet	3%	3%

Completing the Risk Rating Analysis:

The project's reversal risk rating is calculated as follows:

$$100\% - \left(\begin{array}{l} (1 - FinancialFailure\%) \times (1 - IllegalForestBiomassRemoval\%) \times (1 - Conversion\%) \\ \times (1 - OverHarvesting\%) \times (1 - SocialRisk\%) \times (1 - Wildfire\%) \times (1 - Disease/InsectOutbreak\%) \\ \times (1 - OtherCatastrophicEvents\%) \end{array} \right)$$

Appendix E Reforestation Project Eligibility

This appendix presents a standardized approach to determine whether reforestation activities on lands that have undergone a Significant Disturbance are likely to be "business as usual," and therefore not eligible for registration based on the net present value for the timber expected to be produced from reforestation. A reforestation project is considered "business as usual" if the net present value for expected timber is $0 or more according to standard assumptions underlying Table E.1.

To determine whether a reforestation project is eligible, perform the following steps:

1. Identify whether site preparation costs[9] are High or Low:
    a. Site preparation costs are High if:
        i. Competing species management (including mechanical removal and/or use of herbicides) has been or will be conducted on 50 percent or more of the Project Area; or
        ii. Soil ripping has occurred on more than 50 percent of the Project Area.
    b. Site preparation costs are Low for all other projects.
2. Identify the value of harvested products (High, Medium, Low, or Very Low) corresponding to the project's Assessment Area, from the lookup table in the Forest Offset Protocol Resources section of ARB's website.
3. Identify the standard Rotation Age for the project's Assessment Area, from the lookup table in the Forest Offset Protocol Resources section of ARB's website.
4. Identify the site class category for the Project Area. The category must be consistent with the stated site productivity in the project's submission form. Projects with mixed site classes must round to the nearest site class category based on a weighted average.
    a. Site Classes I and II are classified as 'Higher'.
    b. Site Classes III, IV, and V are classified as 'Lower'.
5. Determine whether the project is "eligible" or "not eligible" according to the identified site preparation costs, value of harvested products, rotation age, and site class, as indicated in Table E.1.

[9] All projects are assumed to have similar costs related to the cost of seedlings and planting; site preparation costs, however, can vary depending on circumstances.

Table E.1. Determination of Reforestation Project Eligibility

Site Preparation Costs	Value of Harvested Products	Rotation Age (Length)	Site Class	Eligibility	Scenario #
High Site Preparation	High	Short, Medium, Long	Higher	Not Eligible	1
			Lower	Not Eligible	2
		Extremely Long	Higher	Eligible	3
			Lower	Eligible	4
	Medium	Short, Medium	Higher	Not Eligible	5
			Lower	Not Eligible	6
		Long	Higher	Not Eligible	7
			Lower	Eligible	8
		Extremely Long	Higher	Eligible	9
			Lower	Eligible	10
	Low	Short	Higher	Not Eligible	11
			Lower	Eligible	12
		Medium, Long, Extremely Long	Higher	Eligible	13
			Lower	Eligible	14
	Very Low	Short, Medium, Long, Extremely Long	Higher	Eligible	15
			Lower	Eligible	16
Low Site Preparation	High	Short, Medium	Higher	Not Eligible	17
			Lower	Not Eligible	18
		Long, Extremely Long	Higher	Not Eligible	19
			Lower	Eligible	20
	Medium	Short, Medium	Higher	Not Eligible	21
			Lower	Not Eligible	22
		Long	Higher	Not Eligible	23
			Lower	Eligible	24
		Extremely Long	Higher	Eligible	25
			Lower	Eligible	26
	Low	Short	Higher	Not Eligible	27
			Lower	Not Eligible	28
		Medium	Higher	Not Eligible	29
			Lower	Eligible	30
		Long, Extremely Long	Higher	Eligible	31
			Lower	Eligible	32
	Very Low	Medium, Long, Extremely Long	Higher	Eligible	33
			Lower	Eligible	34
		Short	Higher	Not Eligible	35
			Lower	Not Eligible	36

Appendix F Determining a Value for Common Practice

Quantification Methodology

Forest Assessment Areas Introduction

Assessment areas are used to provide standardized regional data for project development. An assessment area is generally defined as a forest vegetation community that shares common environmental, economical, and regulatory attributes. The Forest Offset Protocol Resources section of ARB's website provides data, by assessment area, necessary to calibrate and/or implement project accounting, including:

- Common Practice – The average carbon stocks (metric tons) of the above ground portion of live trees on private lands. The average carbon stock is the result of the suite of management activities within the assessment area. The common practice value is the extent to which improved forest management projects can receive credit for avoided emissions. (See Section 6.2.)
- Diversity Index – The maximum amount (by carbon percentage) of any one native species allowed within a project. (See Section 3.9.2.)
- The rotation length commonly used in the assessment area and the value of harvest for incorporating in a financial test for reforestation projects (see Appendix E).
- The mill efficiency used for calculating wood products (see Appendix C).
- The wood product classes generated for calculating wood products values (see Appendix C).

Defining Assessment Areas

The U.S. Forest Service Forest Inventory and Analysis Program (FIA) is the basis for development of assessment areas. The FIA program collects data on U.S. forests using an extensive array of coordinated sample plots throughout the nation. Together the plots comprise a national inventory system designed to assess the state of U.S: forests on an ongoing basis. The hierarchical and spatial nature of FIA data make it possible to group sample field plots by geographical location. FIA plots are assigned an attribute referred to as 'forest type' that identifies the dominant vegetation present at the plot. Forest Types were combined into forest communities following a process described further below. An assessment area is a forest community within a defined geographical unit. The geographical units are discussed below.

Ecosections are spatial units and can be mapped. The geographical units that contain assessment areas are based on individual ecosections or combined ecosections (called supersections). Supersections were created in order to stratify the plots into high site class and low site class (where possible) and to increase the statistical reliability of the common practice estimates derived for each assessment area. The combination of ecosections into supersectons only occurred where adjacent ecosections share similar environmental, economic, and regulatory attributes. Ecosections are combined into supersections if:

1. The ecosections are adjacent to each other.
2. They share a similar distribution of plots by forest types, which indicates that the ecosections share similar climate, elevation, and other environmental variables.
3. The economics of forest management are similar between the ecosections. The criteria considered to determine economic commonality between ecosections include forest product generation, transportation networks, forest product mill types, and wood products markets. This was based on professional knowledge of regional timber markets.

4. Regulations between ecosections are relatively homogeneous across ecosection boundaries. Ecosections are not combined into supersections in cases where forest practice regulations between adjoining administrative units are known to be markedly different.

The Forest Service computed the statistics for the combined forest types aggregated at the supersection level and disaggregated at the ecosection level. The statistics are reported on a per acre basis and include board foot volume, basal area (square feet), above ground carbon tons, and the sampling error. Ecosections were not combined into supersections if the aggregation changed average standing carbon stocks of any assessment areas by more than 10%, indicating that there are environmental, economic or regulatory differences affecting the forest stocks within these communities.

The aggregation of forest types into forest communities that define assessment areas is based on the natural forest communities found within the ecosections rather than the presence of a single dominant species as in plantation management. As an example, the Northwest Coast Range contains many forest holdings of intensively managed Douglas-fir forests, yet the natural forest community contains many other species such as western hemlock, Sitka spruce, and red alder, among others. The plots used to define the assessment area, as well as the common practice statistic, are the entire set of plots found in the natural forest community. No effort is made to isolate assessment areas based on the existence of plantations. Successional stage, including the presence of shade tolerance species, and management influence on species prevalence is not a basis for stratifying distinct communities. The Forest Offset Protocol Resources data on ARB's webpage displays the associations of forest species (forest types) and assessment areas for all of the ecosections and supersections. Figure F.1 summarizes conceptually the methodology for delineating assessment areas.

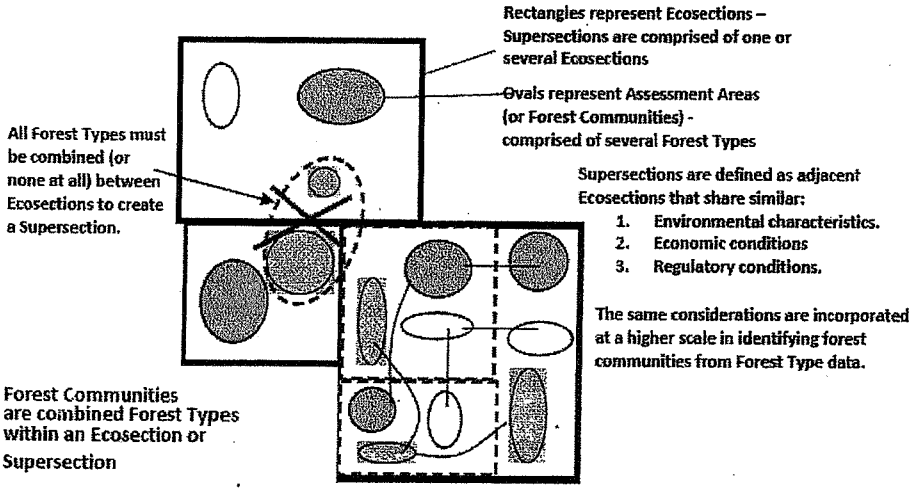


Figure F.1 Schematic of Process to Define Assessment Areas

Determining a Value for Common Practice

The following requirements and methods provide step by step instructions for determining the appropriate Common Practice value for an Improved Forest Management project based on its geographic location and boundaries.

1. **Determine the Geographic Ecosection(s) or Supersection(s) Within Which the Project Area is Located**
   The Offset Project Operator or Authorized Project Designee must determine the geographic Ecosection(s) or Supersection within which the Project Area is located by consulting maps of Supersections. These maps can be downloaded from the Forest Offset Protocol Resources section of ARB's website in either a .pdf format or a Geographical Information System (GIS) shapefile.

2. **Determine the Acreage of the Project Area That Falls Within Each Assessment Area Contained in the Ecosection(s) or Supersection(s)**

   Ecosections and Supersections may consist of one or many Assessment Areas. Assessment Areas are groupings of tree species that are commonly found in association with each other, as in a vegetation community. Assessment Areas are not mapped since the geographic locations of forest communities vary based on highly resolute environmental variables. To determine which Assessment Areas are included within the Project Area, compare the tree species in the Project Area to the species list associated with each Assessment Area in the project's Ecosection(s) or Supersection(s) (identified in Step 1). Tree species information must be looked up using the most current Assessment Area Data File from the Forest Offset Protocol Resources section of ARB's website. The minimum mapping resolution for vegetation communities is 20 acres. Therefore, any contiguous area 20 acres or greater within the Project Area that consists of a separate vegetation community must be independently mapped.

3. **Where Necessary, Stratify Project Area Acres According to Whether They Are High or Low Site Class**

   The Assessment Area Data File on the Forest Offset Protocol Resources section of ARB's website provides data for each Assessment Area by high, low, or all site classes. For Assessment Areas where data are attributed for high and low site classes, the Offset Project Operator or Authorized Project Designee must further stratify the Project Area and identify the acreage that falls within each site class.

   The computation of the statistics in the Assessment Area Data File (on a per acre basis) for board foot volume, basal area (square feet), and CO_2 equivalent was done for high and low site classes wherever the FIA plots were available in adequate quantity to achieve a sampling error of 18 percent or less. The board foot volume and basal area statistics are presented only to elucidate comparisons to the Common Practice (CO_2 equivalent) statistic. Board foot volume and basal area statistics are not used for other purposes in the protocol.

   For stratification purposes, a "high" site class means a Timber Site I or II (Forest Service Types I, II, and III). A low site class means a Timber Site III, IV, or V (Forest Service Types IV – VII). Landowners must determine the portion of the Project Area that is in each site class for each Assessment Area using soils data from a state or federal

agency, direct site class data from a state or federal agency, attestation from a state forester, or through field analysis. Whatever method is used, documentation of the analysis must be provided to the verifier at the project's initial verification.

4. **Identify the Common Practice Statistic Associated with Each Assessment Area and Site Class Stratum**

   For each Assessment Area and Site Class within the Project Area, identify the appropriate Common Practice statistic from Assessment Area Data File. The value displayed in the Assessment Area Data File indicates CO_2 equivalent metric tons per acre in the above ground portion (bole, bark, top and branches) of live trees.

   If data for an Assessment Area are provided for both high and low site classes, and a offset project operator or authorized project designee is unable or unwilling to stratify the Project Area into site classes using an acceptable method described above, then the high site-class Common Practice statistic must be used for all acres within the Assessment Area.

5. **Determine a Value for Common Practice for the Entire Project Area**

   Determine a single Common Practice value for the entire Project Area by calculating the average of the Common Practice statistics for each Assessment Area and site class, weighted by the number of acres of each Assessment Area and site class within the Project Area. See Table F1 for an example.

Table F1. Example of Common Practice Statistic Calculation

Ecosection(s) /Supersection(s)	Assessment Area	Site Class	Acres	Common Practice (Metric Tons CO2-e)
Name the Ecosection(s)/Supersection(s) the project is found within.	*Identify the Assessment Areas the project is in. If the project is in more than one site class for an Assessment Area, enter the Assessment Area twice*	*Enter the Site Class Value*	*Acres for each Assessment Area-Site Class Combination*	*Enter the Value from the most current Assessment Area Data File*
Adirondacks & Green Mountains	Adirondacks & Green Mountains Northeast Conifers	High	1,000	91.8
Adirondacks & Green Mountains	Adirondacks & Green Mountains Northeast Conifers	Low	100	84.4
Adirondacks & Green Mountains	Adirondacks & Green Mountains Northern Hardwood	High	50	102.8
Total Acres / Weighted Average Common Practice			**1,150**	**91.6**

TITLE 17. CALIFORNIA AIR RESOURCES BOARD

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

The Air Resources Board (ARB or Board) will conduct a public hearing at the time and place noted below to consider amendments to California's existing Regulation for the Mandatory Reporting of Greenhouse Gas Emissions (title 17, California Code of Regulations, section 95100 et seq.), which was developed pursuant to requirements of the California Global Warming Solutions Act of 2006.

DATE: December 16, 2010

TIME: 9:00 a.m.

PLACE: California Environmental Protection Agency
Air Resources Board
Byron Sher Auditorium
1001 I Street
Sacramento, California 95814

This item may be considered at a two-day meeting of the Board, which will commence at 9:00 a.m., December 16, 2010, and may continue at 9:00 a.m., December 17, 2010. This item may not be considered until December 17, 2010. Please consult the agenda for the meeting, which will be available at least 10 days before December 16, 2010, to determine the day on which this item will be considered.

INFORMATIVE DIGEST OF PROPOSED ACTION AND POLICY STATEMENT OVERVIEW

Sections Affected: Proposed amendments to sections 95100, 95101, 95102, 95103, 95104, 95105, 95106, 95107, 95108, 95109, 95110, 95111, 95112, 95113, 95114, 95115, 95130, 95131, 95132, and 95133, title 17, California Code of Regulations (CCR). Proposed repeal of section 95125, title 17, CCR. Proposed adoption of new sections 95100.5, 95116, 95117, 95118, 95119, 95120, 95121, 95122, 95123, 95129, 95150, 95151, 95152, 95153, 95154, 95155, 95156, 95157, and 95158, title 17, CCR.

Background

In 2006, the Legislature passed and Governor Schwarzenegger signed the California Global Warming Solutions Act of 2006 (AB 32; Stats. 2006, chapter 488). In AB 32, the Legislature declared that global warming poses a serious threat to the economic well-being, public health, natural resources, and the environment of California.

AB 32 created a comprehensive, multi-year program to reduce GHG emissions in California, with the overall goal of restoring emissions to 1990 levels by the year 2020. One of the requirements of AB 32 is that ARB must adopt a greenhouse gas reporting regulation.

To comply with this requirement, the Board approved the Regulation for the Mandatory Reporting of Greenhouse Gas Emissions (regulation) at its December 2007 Board meeting. The regulation became effective on January 2, 2009. All relevant documents for the rulemaking, including the final regulation, are available at: http://www.arb.ca.gov/regact/2007/ghg2007/ghg2007.htm.

Over the past two years, ARB staff has implemented the California greenhouse gas reporting program established by the regulation. Under the program, over 600 facilities and entities annually submit to ARB their greenhouse gas emissions data reports, which are verified as accurate and complete by ARB-accredited third-party verifiers. Information about the current program can be found at: http://www.arb.ca.gov/cc/reporting/ghg-rep/ghg-rep.htm.

Since the adoption of the Mandatory Reporting Regulation, there have been three significant developments. First, ARB has moved forward with developing a market-based cap-and-trade program for reducing GHG emissions. A successful cap-and-trade program requires very accurate and complete emissions reporting. Second, at the federal level, the United States Environmental Protection Agency (U.S. EPA) has adopted a national mandatory greenhouse gas reporting rule. The U.S. EPA reporting requirements differ from the current ARB reporting requirements, and they were not designed to support a market-based cap-and-trade program. Finally, the Western Climate Initiative (WCI), established in 2007 by Governor Schwarzenegger and the governors and premiers of six other states and four Canadian provinces, has worked to assemble common and consistent reporting requirements out of the framework of U.S. EPA's reporting regulation. WCI's goal has been to create a GHG emissions market within a job-creating green economy among the partner states and provinces, built on a strong foundation of reported emissions data.

Substantial revisions to ARB's current mandatory reporting regulation are necessary in order to align California's GHG emissions reporting with these three developments, to streamline and avoid duplicate GHG reporting, and to still provide the high quality of data needed to support a market-based cap-and-trade program.

A description of the proposed action follows. Many of the proposed amendments were presented at a public workshop held March 23, 2010. ARB staff also discussed its intent to harmonize with U.S. EPA requirements while supporting cap-and-trade; this discussion took place at the U.S. EPA mandatory reporting training session held May 4, 2010, in Los Angeles. Staff considered the comments provided during and after these meetings, as well as public comments provided on the WCI Proposed Harmonized Reporting Requirements, in crafting the staff proposal.

Description of the Proposed Regulatory Action

The purpose of the proposed amendments to the Regulation for the Mandatory Reporting of Greenhouse Gas Emissions is to: (1) harmonize with the U.S. EPA national greenhouse gas reporting requirements, (2) ensure sufficient accuracy and completeness in reporting to support a California greenhouse gas market-based cap-and-trade system, and (3) eventually, support linkage with a WCI regional market system.

To meet these goals, the current ARB mandatory reporting regulation must be substantially altered in form, though the emissions monitoring practices of many reporting entities will not change. Under this proposal, therefore, much of the current regulation would be replaced with new regulatory language. In general, the overall approach has been to start with the U.S. EPA reporting requirements, and then provide additional stringency or specificity where needed to support California cap-and-trade and WCI consistency.

This approach streamlines reporting for those entities subject to both ARB and U.S. EPA reporting rules. An emissions data report that meets the proposed ARB regulation will most often meet the U.S. EPA requirements. This reduces the time and data needed to report, which should reduce costs and result in consistent GHG data reporting across government programs. ARB is also pursuing development of a unified mechanism for federal and state reporting.

The proposed revision requires annual emissions reporting from facilities, fuel and carbon dioxide suppliers, and electric power entities that together account for approximately 87 percent of the total carbon dioxide (CO_2) produced in California from industrial, commercial, and mobile sources of emissions, and similar portions of methane and nitrous oxide emissions. Overall, we estimate that approximately 750 facilities, suppliers and entities would be subject to GHG reporting under the proposed revised regulation, compared to about 600 under the current regulation.

The proposed revised regulation provides specific reporting requirements for each industrial sector, defining which facility processes and GHGs must be reported. In general, all facilities would be required to report their on-site stationary source combustion emissions of CO_2, N_2O (nitrous oxide), and CH_4 (methane). Facilities in some industrial sectors, such as cement, glass production, nitric acid production, and refineries, would also report their process emissions, which occur from chemical or other non-combustion activities. Facilities would report fugitive emissions as specified in the regulation. The CO_2 emissions from biomass-derived fuels would also be separately identified during reporting.

The following paragraphs describe the regulatory requirements according to the level of emissions for a facility or supplier.

Reporters With No Reporting Threshold. For several types of reporting facilities and suppliers, the U.S. EPA regulation and this proposed revision to California's reporting regulation require "whole-sector" reporting. This means that all facilities or suppliers within the industrial sector must report their GHG emissions. In California, this applies to cement production, lime manufacturing, nitric acid production, petroleum refineries, natural gas liquid fractionators, and carbon dioxide suppliers. These types of facilities and suppliers are likely to have emissions that exceed the thresholds below, and their reporting and verification requirements are similar to those above the 25,000 metric tons (MT) of CO_2 equivalent (CO_2e) threshold.

In addition the ARB regulation would continue to require reporting by importers and exporters of electric power; there is no emissions threshold associated with these requirements. Other electricity retail providers would continue to report their retail sales, but would be relieved of many current reporting requirements that were in place for a possible load-based point of regulation in the electricity sector.

Reporters Over 25,000 MT of CO_2e. Under the proposed revision, the majority of facilities currently subject to reporting will still be required to report. Full reporting is required for facilities emitting at least 25,000 metric tons of CO_2e emissions per year, most of which will hold a cap-and-trade compliance obligation under ARB's cap-and-trade program. Those subject to the proposed revised regulation include electricity generating and cogeneration facilities, electric retail providers and other importers and exporters of electric power, oil refineries, hydrogen plants, cement plants, and other facilities that meet CO_2e reporting thresholds for stationary combustion and industrial processes, including producers of glass, nitric acid, iron and steel, and manufacturers of lime and pulp and paper. The addition of process emissions from these sources in California is consistent with U.S. EPA reporting requirements. The proposal would also require that these facilities provide their consumption of purchased or acquired electricity and thermal energy; this is consistent with the current ARB regulation and will be used to support ARB regulatory programs.

In addition to reporting by industrial facilities, most of which report under the current regulation, the proposed revised regulation requires new reporting by fuel suppliers (suppliers of transportation fuels, suppliers of natural gas, natural gas liquids, and liquefied petroleum gas), and suppliers of carbon dioxide. Reporting by fuel suppliers would substantially increase the emissions coverage of the regulation, which is necessary to support a broad cap-and-trade program that includes these sources by 2015. Also covered by the U.S. EPA regulation, suppliers report the GHGs to be emitted from the eventual combustion or use of the products supplied. To limit reporting of transportation fuels to those resulting in emissions in California, the regulation would require reporting by position holders (fuel owners) at terminal racks and refineries, and enterers (importers) of petroleum products and biofuels outside the terminal system. GHG reporting would follow practices that are already used by these suppliers to determine fuel taxes payable to the California Board of Equalization, so the addition of GHG reporting requirements should not be too

burdensome.

The proposed revised regulation also includes requirements for emissions reporting by facilities in the oil and gas exploration and production sector. These requirements are included in anticipation of finalization of the U.S. EPA proposal (known as Subpart W) for reporting GHG emissions by the oil and gas exploration and production sector. The proposed ARB requirements are based on the U.S. EPA proposal for most source types, but for some source types in this sector (as in other sectors) additional requirements are proposed to ensure the accuracy needed to support market emissions trading. Because final U.S. EPA action may not occur prior to the release of this proposal, full proposed regulatory text is included as Subarticle 5 of the revised regulation.

Schedule and Due Dates. The data specified in the proposed revised regulation would be reported to ARB annually, for the previous calendar year. The first emissions reports under the proposed revised regulation, for 2011 emissions, would be submitted in 2012. Facilities and suppliers would be permitted to report on 2011 emissions using only the requirements in the U.S. EPA regulation, in recognition that any needed shifts in monitoring practices to comply with the new ARB requirements may not be implemented until 2012. Most reports would be due April 1 of each year; electric power entities would have until June 1 to allow enough time for compilation of purchase and sales data for the previous year.

Missing Data Substitution. The proposed revised regulation includes new specifications for the replacement of missing emissions and fuel monitoring data needed for meeting the requirements of the regulation. Because the U.S. EPA regulation was not designed for a cap-and-trade program, these additional elements are intended to prevent abuse of monitoring practices that would undermine fairness in a market program. They are based on similar requirements developed for the U.S. EPA Acid Rain Program.

Third Party Verification. Most facilities and entities subject to the proposed revised regulation would be required to contract with a third-party verification body (which may include local air pollution control or air quality management districts) for the verification of their submitted emissions data reports, to ensure the completeness and accuracy of the data and to confirm the use of required methods in preparing the emission estimates. Verification would be performed annually, with more comprehensive reviews, including site visits, at least once during a three-year compliance period under the market program. Verification would be required by September 1 for facilities and suppliers, and by October 1 for electric power entities. Verification services specified in the regulation must be performed by ARB-accredited verifiers. The verification and verifier accreditation requirements are not significantly different from current ARB requirements (most facilities and entities affected by the proposed revised regulation are already subject to third-party verification), but some additional language has been added to provide for the accreditation of offset project verifiers.

Reporters Below 25,000 MT of CO_2e. Facilities and suppliers with emissions between 10,000 metric tons and 25,000 metric tons of CO_2e would be included in the mandatory reporting program, but would have abbreviated reporting requirements. These reporters would report their combustion emissions using default emission factors or any other method of their choosing from the U.S. EPA regulation. They would also report process emissions, although these are unlikely to occur at facilities of this size. Only some oil-and-gas production facilities and a few glass production facilities are likely to have process emissions to report.

Under the current regulation, only power plants report within this emissions range. Under the revised regulation, power plants would continue to report down to 10,000 MT of CO_2e, but may use a simplified calculation approach. They would also report some basic information on their power generation or cogeneration systems, such as generating capacity and the amount of power generated.

Reporters in this range would also report process information associated with their emissions, such as fuel use. This will enable ARB staff to check the emissions calculation as part of their review of these reports.

As part of the streamlined approach for reporters in this range, they would not be subject to other regulatory requirements for third-party verification, missing data substitution, or calibration and measurement accuracy. This will minimize costs while providing ARB a means of monitoring what is happening "below the cap" for the cap-and-trade program. This feature of the regulation is part of the WCI design recommendation.

Reporters No Longer Affected. The current ARB reporting regulation requires reporting by power plants and cogeneration facilities emitting between 2,500 and 10,000 metric tons of CO_2e. These facilities will no longer be subject to reporting requirements. No facility or supplier below 10,000 MT of CO_2e will be required to report to California, except in the unlikely case one is brought in by U.S. EPA whole-sector requirements.

Other Items. Other items included in the proposed revised regulation are the detailed quantification and reporting requirements for each industrial sector, requirements for the substitution of missing data, required elements of verification services, verifier accreditation requirements, specifications for claiming confidential data, and document retention and record keeping requirements. Also in the proposal, the current requirements for SF_6 (sulfur hexafluoride) and HFCs (hydrofluorocarbons) reporting in the electricity sector have been removed because this information is being reported more comprehensively through other ARB programs. Complete details are provided in the proposed regulation and the Initial Statement of Reasons, which are available at:
http://www.arb.ca.gov/regact/2010/ghg2010/ghg2010.htm

DOCUMENTS INCORPORATED BY REFERENCE

The following documents would be incorporated in the regulation by reference: *Mandatory Reporting of Greenhouse Gases; Final Rule.*, 40 Code of Federal Regulations (CFR) Parts 86, 87, 89, 90, 94, and 98 (October 30, 2009); *Mandatory Reporting of Greenhouse Gases from Magnesium Production, Underground Coal Mines, Industrial Wastewater Treatment, and Industrial Waste Landfills; Final Rule.*, 40 CFR Part 98 (July 12, 2010); *Mandatory Reporting of Greenhouse Gases; Final Rule* (Corporate Parent/NAICS Code Amendments), 40 CFR Part 98 (September 22, 2010); *Mandatory Reporting of Greenhouse Gases; Final Rule (Technical Corrections, Clarifying and Other Amendments to Certain Provisions of the Mandatory Greenhouse Gas Reporting Rule)*, 40 CFR Parts 86 and 98 (October 7, 2010); 40 CFR Part 75 (July 1, 2009); 40 CFR Part 60, subpart A, §60.18(i)(1) and (2) (revised as of July 1, 2009); *The American Association of Petroleum Geologists Bulletin*, V. 75, No. 10, pp. 1644-1651 (October 1991); American Society for Testing and Materials (ASTM) D388, *Standard Classification of Coals by Rank* (September 2005); ASTM D4806, *Standard Specification for Denatured Fuel Ethanol for Blending with Gasolines for Use as Automotive Spark-Ignition Engine Fuel* (August 2008); ASTM D6751, *Standard Specification for Biodiesel Fuel Blend Stock (B100) for Middle Distillate Fuels* (October 2008); and, *Year 2005 Gulfwide Emission Inventory Study (GOADS)*, U.S. Department of the Interior, Minerals Management Service, Gulf of Mexico OCS Region, MMS 2007-067 (2007).

In addition to the documents listed above, the proposed regulation would also incorporate by reference two software programs: *Production Tank Model – A Program for Estimating Emissions from Hydrocarbon Production Tanks – E&P Tank Version 2.0*, American Petroleum Institute (2000) and *GRI-GLYCalc™ Version 4.0*, Gas Technology Institute (2008).

COMPARABLE FEDERAL REGULATIONS

As mentioned previously, the U.S. EPA requires mandatory GHG reporting (*Mandatory Reporting of Greenhouse Gases; Final Rule.* 40 CFR Parts 86, 87, 89, 90, 94, and 98. United States Environmental Protection Agency. October 30, 2009). This proposed revised regulation was developed to minimize, to the greatest extent possible, any redundant State and federal reporting. Without adoption of the proposed revised regulation, reporters would have to submit duplicative GHG emissions reports based on different requirements, estimation methods, and reporting systems, in order to comply with different ARB and U.S. EPA reporting requirements for GHG data.

In addition, the U.S. EPA's Acid Rain Program requires the reporting of CO_2, SO_2, and NO_x emissions from certain fossil fueled power plants as part of its program to reduce atmospheric levels of sulfur dioxide and nitrogen oxides (see Title 40, Code of Federal Regulations, section 72.1 et seq.). Because of the very limited nature of this federal regulation related to GHG emissions reporting, the proposed revised ARB regulation is not duplicative of this federal requirement. The missing data elements in the proposed

amendments are largely based on elements in the Acid Rain Program, which were developed to support emissions trading.

AVAILABILITY OF DOCUMENTS AND AGENCY CONTACT PERSONS

ARB staff has prepared a Staff Report: Initial Statement of Reasons (ISOR) for the proposed regulatory action, which includes a summary of the economic and environmental impacts of the proposal. The ISOR is entitled: "Staff Report: Initial Statement of Reasons for Rulemaking: Revisions to the Regulation for Mandatory Reporting of Greenhouse Gas Emissions."

Copies of the ISOR and the full text of the proposed regulatory language may be accessed on ARB's web site listed below, or may be obtained from the Public Information Office, Air Resources Board, 1001 I Street, Visitors and Environmental Services Center, First Floor, Sacramento, California, 95814, or by calling (916) 322-2990 within the 45 days prior to the scheduled hearing on December 16, 2010.

Upon its completion, a Final Statement of Reasons (FSOR) will be available and copies may be requested from the agency contact persons in this notice, or may be accessed on ARB's website listed below.

Inquiries concerning the substance of the proposed regulation may be directed to the designated agency contact persons, Mr. Doug Thompson, Manager of ARB Climate Change Reporting Section, Planning and Technical Support Division at (916) 322-7062, or Mr. Patrick Gaffney, Staff Air Pollution Specialist, at (916) 322-7303.

Further, the agency representative and designated back-up contact persons to whom nonsubstantive inquiries concerning the proposed administrative action may be directed are Ms. Lori Andreoni, Manager, Board Administration & Regulatory Coordination Unit (916) 322-4011, or Ms. Amy Whiting, Regulations Coordinator, (916) 322-6533. The Board staff has compiled a record for this rulemaking action, which includes all the information upon which the proposal is based. This material is available for inspection upon request to the contact persons.

This notice, the ISOR and all subsequent regulatory documents, including the FSOR, when completed, are available on ARB's website for this rulemaking at: http://www.arb.ca.gov/regact/2010/ghg2010/ghg2010.htm

COSTS TO PUBLIC AGENCIES AND TO BUSINESSES AND PERSONS AFFECTED

The determinations of the Board's Executive Officer concerning the costs or savings necessarily incurred by public agencies, private persons and businesses in reasonable compliance with the proposed regulatory action are presented below. A detailed assessment of the economic impacts of the proposed regulation is included in the Initial Statement of Reasons for this regulatory item.

The Executive Officer has made an initial determination that the proposed regulatory action would not have a significant statewide adverse economic impact directly affecting businesses, including the ability of California businesses to compete with businesses in other states, or on representative private persons. Because the proposed revised regulation provides harmonization with the U.S. EPA greenhouse gas reporting requirements, most facilities subject to the U.S. EPA requirements will only have a small incremental cost to comply with the ARB regulations. In most cases, data and analysis will be performed in compliance with the U.S. EPA regulation, and the data will also meet ARB requirements.

For most facilities not subject to U.S. EPA reporting, but subject to the ARB proposal, reporting costs will typically be modest. This is because these facilities will generally be able to use the abbreviated reporting option, which provides simple estimation methods, or because readily available data may be used to complete reporting. The reporting costs will be low relative to typical facility revenues; therefore the affected businesses newly added to GHG reporting as part of this proposal should be able to absorb the costs of the proposed regulation with no significant adverse impacts on their profitability. Staff does not expect a noticeable change in employment, business creation, elimination or expansion, or business competitiveness in California due to the proposed revisions.

In developing this regulatory proposal, ARB staff evaluated the potential economic impacts on representative private persons or businesses and determined that there would be a potential net incremental cost impact on private persons and businesses directly affected. Staff estimates that the total incremental net costs associated with meeting the proposed revisions, beyond what is incurred in complying with the U.S. EPA regulation, to be $18 million over the course of 10 years for businesses, local, and State government. Initial annual reporting costs will be higher due to the possible need for new equipment, sampling systems, training, and other start-up costs to meet the regulatory requirements. Chapter VI of the ISOR for the proposed regulation includes additional data on the estimated costs to facilities.

Determining the specific cost for an individual facility subject to the proposed revised regulation is complex because incremental costs vary by facility type, the complexity of the facility, and applicable reporting requirements. For many facilities and suppliers there should be minimal additional costs over those needed to comply with the U.S. EPA reporting regulation, and monitoring practices may not differ from practices currently used to comply with the existing ARB regulation. For facilities and suppliers not required to report to U.S. EPA, or to ARB currently, incremental costs will be more significant. We estimate that on average the costs of complying with the ARB proposal will be about $5,000 for typical reporters. Actual costs will be higher or lower than this "typical" value based on the complexity of the reporting facility or entity. Implementation of the regulation will also produce a cost savings for some reporters as a result of reduced requirements, or because some facilities will no longer be subject to reporting.

Additional information on the facility cost analysis can be found in Chapter VI of the ISOR for this regulatory action.

Staff anticipates that the additional costs for reporting can be easily absorbed under existing operating expenses for most facilities and suppliers, even those for whom reporting is new. Facilities below 25,000 metric tons will be allowed to complete abbreviated reports without the need for new equipment or fuel sampling and testing, and do not need to contract with third-party verifiers. Suppliers of transportation fuels will be following established practices for tax law compliance. Verification costs will apply to suppliers, but because their reports are relatively simple, their costs should generally be lower than those of other reporting entities.

Electric power entities are not required to report to U.S. EPA, but currently report to ARB if they import power to California. Their reports will change under the proposed revised regulation, but costs should not increase. This is because much of the detailed data currently reported by electric power entities will no longer be required to be reported. Retail providers who are not importing or exporting power will report only retail sales figures. Importers and exporters will need to track and report electricity transactions and calculate emissions, and they will also need to continue to contract with third-party verifiers. But, because reporting and verification has become part of the established business practices for these businesses, implementation of the proposed regulation should not produce cost increases, and in some cases it should lead to cost savings for reporters.

The Executive Officer has determined, pursuant to title 1, CCR, section 4, that the proposed regulatory action will affect small businesses. Staff estimates that approximately 185 small businesses may be affected in California. The proposed revised regulation is designed to minimize costs to these businesses by providing simplified emission estimation methods. Many of the affected small businesses will take advantage of abbreviated reporting and will not face verification costs. Based on the types of small business expected to be impacted and the kinds of GHG generating activities present at these facilities, the incremental reporting and verification costs for a typical small business subject to the regulation should be approximately $4,000 for the first year and $2,000 per year for future years.

Some public agencies could also be subject to GHG reporting, such as certain county or city owned sewage treatment works or landfills, various utility districts or publicly owned electricity providers, some State universities, prisons and other State facilities that emit more than 10,000 metric tons of CO_2e from stationary combustion sources. Most of California's public and private electricity retail providers will experience diminished reporting costs, as they will no longer need to compile data that was previously collected to support a load-based point of regulation. The Department of Water Resources will continue to have a reporting requirement related to imported power. The additional costs incurred by these State and local government agencies in total as a result of this regulatory proposal are not expected to be significant. A net savings for local agencies of approximately $260,000 per year is expected, mostly due to reduced reporting

requirements for municipal utilities.

As described above, the proposed regulatory action will impose a mandate upon and create costs to some local agencies. Because the regulatory requirements apply equally to all reporting categories and unique requirements are not imposed on local agencies, the Executive Officer has determined that the proposed regulatory action imposes no costs on local agencies that are required to be reimbursed by the state pursuant to part 7 (commencing with section 17500), division 4, title 2 of the Government Code, and does not impose a mandate on local agencies that is required to be reimbursed pursuant to Section 6 of Article XIII B of the California Constitution.

Adoption of the proposed revisions is expected to require new funding for ARB to administer the program. Approximately 2.0 staff members will be redirected from existing staffing to administer the new program beginning in FY2011/2012. In addition, approximately $250,000 per year will be required over a three-year period for reporting system improvements as staff works to integrate State reporting with U.S. EPA reporting systems, and then an additional $150,000 per year is needed on an ongoing basis for operations and maintenance of the reporting systems.

In accordance with Government Code section 11346.3, the Executive Officer has initially determined that the proposed regulatory action will not result in an elimination of jobs within the State of California, or the creation or elimination of existing businesses within the State. In fact, jobs were added as a result of the original reporting regulation because it created the need for technical support for developing GHG emissions estimates, providing laboratory and other services, and providing emission verification services. These existing jobs should be retained, and some new jobs may be created as the breadth of the current reporting regulation expands.

Pursuant to Government Code sections 11346.5(a)(5) and 11346.5(a)(6), the Executive Officer has determined that the proposed regulatory action would not create costs or savings in federal funding to the state, or costs or mandate to any school district whether or not reimbursable by the state pursuant to Part 7 (commencing with section 17500), division 4, title 2 of the Government Code.

In accordance with Government Code sections 11346.3(c) and 11346.5(a)(11), the Executive Officer has found that the reporting requirements of the regulation which apply to businesses are necessary for the health, safety, and welfare of the people of the State of California.

Before taking final action on the proposed regulatory action, the Board must determine that no reasonable alternative considered by the Board or that has otherwise been identified and brought to the attention of the Board, would be more effective in carrying out the purpose for which the action is proposed or would be as effective and less burdensome to affected private persons than the proposed action.

SUBMITTAL OF COMMENTS

Interested members of the public may present comments relating to this matter orally or in writing at the hearing, and comments may also be submitted by postal mail or electronic submittal before the hearing. The public comment period for this regulatory item will begin on November 1, 2010. To be considered by the Board, written submissions not physically submitted at the hearing must be submitted on or after November 1, 2010, and received **no later than 12:00 noon, December 15, 2010**, and must be addressed to the following:

Postal Mail: Clerk of the Board, Air Resources Board
1001 I Street, Sacramento, California 95814

Electronic submittal: http://www.arb.ca.gov/lispub/comm/bclist.php

To ensure that your comment will be available for consideration it is important that your comment is received by the deadline.

Please note that under the California Public Records Act (Government Code section 6250 et. seq.), your written and oral comments, attachments, and associated contact information becomes part of the public record and can be released to the public upon request. This includes personal information provided with your comments, such as your home address, your home phone number, and your personal email address. Additionally, your comments, attachments, and associated contact information may become available via internet search engines.

The Board requests, but does not require, that 20 copies of any written statement be submitted and that all written statements be filed at least 10 days prior to the hearing so that ARB staff and Board Members have time to fully consider each comment. The Board encourages members of the public to bring to the attention of staff in advance of the hearing any suggestions for modification of the proposed regulatory action.

STATUTORY AUTHORITY AND REFERENCES

This regulatory action is proposed under that authority granted in Health and Safety Code, sections 38510, 38530, 38580, 39600, 39601, 39607, 39607.4, and 41511. This action is proposed to implement, interpret and make specific sections 38530, 38580, 39600, 39607, 39607.4, and 41511 of the Health and Safety Code.

HEARING PROCEDURES

The public hearing will be conducted in accordance with the California Administrative Procedure Act, title 2, division 3, part 1, chapter 3.5 (commencing with section 11340) of the Government Code.

Following the public hearing, the Board may adopt the regulatory language as originally proposed or with nonsubstantial or grammatical modifications. The Board may also adopt the proposed regulatory language with other modifications if the text as modified is sufficiently related to the originally proposed text that the public was adequately placed on notice that the regulatory language as modified could result from the proposed regulatory action. In the event that such modifications are made, the full regulatory text, with the modifications clearly indicated, will be made available to the public for written comment at least 15 days before it is adopted.

The public may request a copy of the modified regulatory text from ARB's Public Information Office, Air Resources Board, 1001 I Street, Visitors and Environmental Services Center, First Floor, Sacramento, California, 95814, (916) 322-2990.

SPECIAL ACCOMMODATION REQUEST

Special accommodation or language needs can be provided for any of the following:

- An interpreter to be available at the hearing;
- Documents made available in an alternate format (i.e., Braille, large print, etc.) or another language;
- A disability-related reasonable accommodation.

To request these special accommodations or language needs, please contact the Clerk of the Board at (916) 322-5594 or by facsimile at 916) 322-3928 as soon as possible, but no later than 10 business days before the scheduled Board hearing. TTY/TDD/Speech to Speech users may dial 711 for the California Relay Service.

Comodidad especial o necesidad de otro idioma puede ser proveído para alguna de las siguientes:

- Un intérprete que esté disponible en la audiencia
- Documentos disponibles en un formato alterno (por decir, sistema Braille, o en impresión grande) u otro idioma.
- Una acomodación razonable relacionados con una incapacidad.

Para solicitar estas comodidades especiales o necesidades de otro idioma, por favor llame a la oficina del Consejo al (916) 322-5594 o envíe un fax a (916) 322-3928 lo

más pronto posible, pero no menos de 10 días de trabajo antes del día programado para la audiencia del Consejo. TTY/TDD/Personas que necesiten este servicio pueden marcar el 711 para el Servicio de Retransmisión de Mensajes de California.

CALIFORNIA AIR RESOURCES BOARD

James N. Goldstene
Executive Officer

Date: October 19, 2010

The energy challenge facing California is real. Every Californian needs to take immediate action to reduce energy consumption. For a list of simple ways you can reduce demand and cut your energy costs, see our website at www.arb.ca.gov.

STATE OF CALIFORNIA

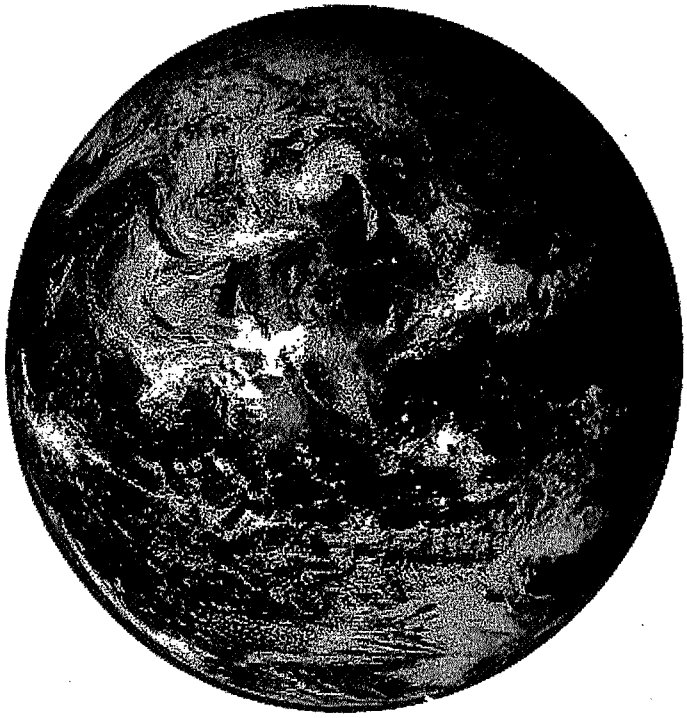
California Environmental Protection Agency

AIR RESOURCES BOARD

STAFF REPORT: INITIAL STATEMENT OF REASONS FOR RULEMAKING

REVISIONS TO THE

REGULATION FOR MANDATORY REPORTING OF GREENHOUSE GAS EMISSIONS PURSUANT TO THE CALIFORNIA GLOBAL WARMING SOLUTIONS ACT OF 2006 (ASSEMBLY BILL 32)



Planning and Technical Support Division
Emission Inventory Branch

October 28, 2010

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STATE OF CALIFORNIA

California Environmental Protection Agency
AIR RESOURCES BOARD

STAFF REPORT: INITIAL STATEMENT OF REASONS FOR RULEMAKING

PUBLIC HEARING TO CONSIDER

REVISIONS TO MANDATORY REPORTING OF GREENHOUSE GAS EMISSIONS PURSUANT TO THE CALIFORNIA GLOBAL WARMING SOLUTIONS ACT OF 2006 (ASSEMBLY BILL 32)

Release Date: October 28, 2010
Scheduled for Consideration: December 16, 2010

This report has been prepared by the staff of the California Air Resources Board and approved for publication. Publication does not signify that the contents necessarily reflect the views and policies of the Air Resources Board.

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STAFF REPORT: INITIAL STATEMENT OF REASONS

PUBLIC HEARING TO CONSIDER

REVISIONS TO MANDATORY REPORTING OF GREENHOUSE GAS EMISSIONS PURSUANT TO THE CALIFORNIA GLOBAL WARMING SOLUTIONS ACT OF 2006

Air Resources Board Meeting
December 16, 2010 at 9:00 a.m.
Air Resources Board
Cal/EPA Headquarters
Sher Auditorium
1001 I Street
Sacramento, CA 95814

This item will be considered at a two-day meeting of the Board, which will commence at 9:00 a.m. on December 16, 2010, and may continue to 9:00 a.m., December 17, 2010. Please consult the agenda for the meeting, which will be available at least ten days before December 16, 2010, to determine the day on which this item will be considered.

For those unable to attend the meeting in person, a live video webcast will be available beginning at 9:00 a.m. on December 16, 2010, at http://www.calepa.ca.gov/broadcast

This report and related materials are available for download from the Air Resources Board's Internet site at: http://www.arb.ca.gov/regact/2010/ghg2010/ghg2010.htm. In addition, written copies may be obtained from the Board's Public Information Office, 1001 I Street, 1st Floor, Environmental Services Center, Sacramento, California 95814, (916) 322-2990.

If you have a disability-related accommodation need, please go to: http://www.arb.ca.gov/html/ada/ada.htm for assistance or contact the ADA Coordinator at (916) 323-4916. If you are a person who needs assistance in a language other than English, please contact the Bilingual Coordinator at (916) 324-5049 or go to: http://inside.arb.ca.gov/as/eeo/languageaccess.htm.

Questions
If you have questions concerning this report, please contact:

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Prepared By Planning and Technical Support Division,
Emission Inventory Branch
Climate Change Reporting Section
Climate Change Verification & Protocols Section

Reviewed by
Office of Legal Affairs
Planning and Technical Support Division

Acknowledgments

This report was prepared with the assistance and support of many individuals within the Air Resources Board. In addition, staff would like to acknowledge the assistance and cooperation of many private individuals and organizations, whose contributions throughout the regulation development process have been invaluable. Finally, staff would like to acknowledge the significant contributions of numerous state, provincial, and federal government agencies that have provided assistance throughout the rulemaking process.

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ATTACHMENT D: 40 CFR Part 98 (October 30, 2009), Rule Sections Incorporated by Reference in the Proposed Regulation.

ATTACHMENT E: 40 CFR Part 98 (July 12, 2010), Rule Sections Incorporated by Reference in the Proposed Regulation.

ATTACHMENT F: 40 CFR Part 98 (September 22, 2010), Rule Sections Incorporated by Reference in the Proposed Regulation.

ATTACHMENT G: 40 CFR Part 98 (October 7, 2010), Rule Sections Incorporated by Reference in the proposed Regulation.

ATTACHMENT H: 40 CFR Part 75 (revised as of July 1, 2009), Rule Sections Incorporated by Reference in the Proposed Regulation.

EXECUTIVE SUMMARY

This report presents proposed revisions to the California Regulation for the Mandatory Reporting of Greenhouse Gas Emissions. The regulation was originally developed pursuant to the California Global Warming Solutions Act of 2006 (the Act), and adopted by the Air Resources Board (ARB) in December 2007. The proposed revision to the regulation is necessary to support a California greenhouse gas (GHG) cap-and-trade program and to harmonize with the U.S. Environmental Protection Agency (U.S. EPA) federal mandatory GHG reporting requirements contained in 40 Code of Federal Regulations (CFR) Part 98. The revisions are also necessary, and authorized, to "prepare, adopt, and update" California's inventory of emissions related to climate change formerly conducted by the State Energy and Natural Resources Conservation and Development Commission pursuant to Chapter 8.5 (commencing with Section 25730) of Division 15 of the Public Resources Code. (California Health & Safety Code sections 39600, 39601, 39607, 39607.4, and 41511).

Objectives of the Proposed Regulation and Revisions

ARB staff has developed the proposed revisions to meet the requirements of the Act, the statutes listed above, and to:

- collect data that are sufficiently rigorous and consistent to support GHG cap-and-trade and other ARB programs;
- harmonize California reporting requirements with U.S. EPA reporting requirements to simplify and streamline GHG reporting;
- provide consistency with Western Climate Initiative reporting requirements while addressing specific California needs under AB 32 and other state law;
- provide for third-party verification of reported emissions data consistent with international standards.

The proposed revisions are strongly based on the U.S. EPA greenhouse gas mandatory reporting regulation adopted in 2009 (U.S. EPA MRR). ARB staff, in an intensive collaboration with colleagues in other states and provinces participating in the Western Climate Initiative (WCI), carefully reviewed the U.S. EPA regulation and developed harmonized calculation and reporting requirements. These proposed requirements include targeted modifications and enhancements to the U.S. EPA rule that are necessary to fully support a cap-and-trade program. Key additions to the U.S. EPA baseline requirements include third-party verification, more rigorous missing data provisions, and specifying emissions calculation methods that will work in a market context by accounting for the carbon variability of fuel consumed.

Context and Approach for the Proposed Regulation

Since the adoption of California's Regulation for the Mandatory Reporting of GHG Emissions in 2007 (ARB MRR 2007), there have been three significant developments:

- ARB has moved forward with developing a market-based cap-and-trade program for reducing GHG emissions, as called for in the adopted Scoping Plan. A successful cap-and-trade program requires very accurate and complete emissions reporting, which for some sources will require increased stringency in the ARB reporting regulation.
- The U.S. EPA has adopted a nationwide mandatory greenhouse gas reporting program (USEPA MRR 2009-2010). The U.S. EPA reporting requirements differ from the current ARB reporting requirements, and were not designed to support a cap-and-trade program. This potentially creates a confusing and duplicative regulatory environment for reporting GHG emissions to California and the U.S. EPA.
- The WCI, established in 2007 by Governor Schwarzenegger and the governors and premiers of six other states and four Canadian provinces, has worked to assemble common and consistent reporting requirements out of the framework of U.S. EPA's regulation. WCI's goal has been to create a GHG emissions market within a job-creating green economy among the partner states and provinces, built on a strong foundation of reported emissions data.

These developments made it clear that the existing regulation required revisions to support cap-and-trade, align with the U.S. EPA regulation to the maximum extent feasible and consistent with the needs of a market-based control program, and provide consistency with the broad-based WCI requirements – while still complying with the AB 32 requirements under which the current regulation was developed. The revisions are also necessary to update the inventory of emissions related to climate change as required by California law.

To achieve these ends, the proposed ARB reporting regulation is substantially altered in form, though the emissions monitoring practices of many reporters will not change. Under this proposal much of the current regulation is replaced with new regulatory language that cites, and where necessary, qualifies federal reporting requirements for use in meeting California reporting requirements. The staff's overall approach has been to begin with the U.S. EPA reporting requirements as a baseline, and then provide additional stringency or specificity where needed to support cap-and-trade and other ARB program elements.

This approach streamlines reporting for those entities subject to both state and federal rules, because an emissions report that meets the proposed ARB regulation will usually also meet the U.S. EPA requirements. It reduces the time and data development needed to compile emissions reports, allowing for reduced costs and consistent GHG data across government programs. At the same time, ARB is working with U.S. EPA to develop a unified mechanism for federal and state reporting to reduce or eliminate the need for separate reporting to ARB and U.S. EPA. We hope to have this unified approach in place in time for reporting of 2011 emissions in 2012.

Overview of the Proposed Regulation

The proposed regulation requires annual emissions reporting from facilities, fuel and carbon dioxide (CO_2) suppliers, and electric power entities that together account for approximately 87 percent of the total CO_2 produced by California from industrial, commercial, and mobile sources of emissions, and similar portions of methane and nitrous oxide emissions. Overall, we estimate that approximately 750 facilities, suppliers and entities would be subject to GHG reporting under the proposed revised regulation, compared to about 600 under the current regulation. Given that various facilities, suppliers, and entities are under common ownership, staff estimates that this equates to approximately 450 businesses.

Who Is Affected and Reporting Thresholds.

Reporters With No Reporting Threshold. For several types of reporting facilities and suppliers, the U.S. EPA regulation and this proposed revision to California's reporting regulation require "whole-sector" reporting. This means that all facilities or suppliers within the industrial sector must report their GHG emissions. In California, this applies to cement production, lime manufacturing, nitric acid production, petroleum refineries, natural gas liquid fractionators, and carbon dioxide suppliers. These types of facilities and suppliers are likely to have emissions that exceed the thresholds below, and their reporting and verification requirements are similar to those above the 25,000 metric tons (MT) of CO_2 equivalent (CO_2e) threshold.

In addition, the ARB regulation would continue to require reporting by importers and exporters of electric power; there is no emissions threshold associated with these requirements. Other electricity retail providers would continue to report their retail sales, but would be relieved of many current reporting requirements that were in place for a possible load-based point of regulation in the electricity sector.

Reporters Over 25,000 MT of CO_2e. Under the proposed revision, the majority of facilities currently subject to reporting will still be required to report. Full reporting is required for facilities emitting at least 25,000 metric tons of CO_2e emissions per year, most of which will hold a cap-and-trade compliance obligation under ARB's cap-and-trade program. Those subject to the proposed revised regulation include electricity generating and cogeneration facilities, electric retail providers and other importers and exporters of electric power, oil refineries, hydrogen plants, cement plants, and other facilities that meet CO_2e reporting thresholds for stationary combustion and industrial processes, including producers of glass, nitric acid, iron and steel, and manufacturers of lime and pulp and paper. The addition of process emissions from these sources in California is consistent with U.S. EPA reporting requirements. The proposal would also require that these facilities provide their consumption of purchased or acquired electricity and thermal energy; this is consistent with the current ARB regulation (ARB MRR 2007) and will be used to support ARB regulatory programs.

In addition to reporting by industrial facilities, most of which report under the current regulation, the proposed revised regulation requires new reporting by fuel suppliers (suppliers of transportation fuels, suppliers of natural gas, natural gas liquids, and liquefied petroleum gas), and suppliers of carbon dioxide. Reporting by fuel suppliers would substantially increase the emissions coverage of the regulation, which is necessary to support a broad cap-and-trade program that includes these sources by 2015. Also covered by the U.S. EPA regulation, suppliers report the GHGs to be emitted from the eventual combustion or use of the products supplied. To limit reporting of transportation fuels to those resulting in emissions in California, the regulation would require reporting by position holders (fuel owners) at terminal racks and refineries, and enterers (importers) of petroleum products and biofuels outside the terminal system. GHG reporting would follow practices that are already used by these suppliers to determine fuel taxes payable to the California Board of Equalization, so the addition of GHG reporting requirements should not be too burdensome.

The proposed revised regulation also includes requirements for emissions reporting by facilities in the oil and gas exploration and production sector. These requirements are included in anticipation of finalization of the U.S. EPA proposal (known as Subpart W, USEPA 2010w) for reporting GHG emissions by the oil and gas exploration and production sector. The proposed ARB requirements are based on the U.S. EPA proposal for most source types, but for some source types in this sector (as in other sectors) additional requirements are proposed to ensure the accuracy needed to support market emissions trading. Because final U.S. EPA action may not occur prior to the release of this proposal, full proposed regulatory text is included as Subarticle 5 of the revised regulation.

Reporters Below 25,000 MT of CO_2e. Facilities and suppliers with emissions between 10,000 metric tons and 25,000 metric tons of CO_2e would be included in the mandatory reporting program, but would have abbreviated reporting requirements. These reporters would report their combustion emissions using default emission factors or any other method of their choosing from the U.S. EPA regulation (USEPA MRR 2009-2010). They would also report process emissions, although these are unlikely to occur at facilities of this size. Only some oil-and-gas production facilities and a few glass production facilities are likely to have process emissions to report.

Under the current regulation, only power plants report within this emissions range (ARB MRR 2007). Under the revised regulation, power plants would continue to report down to 10,000 MT of CO_2e, but may use a simplified calculation approach. They would also report some basic information on their power generation or cogeneration systems, such as generating capacity and the amount of power generated.

Reporters in this range would also report process information associated with their emissions, such as fuel use. This will enable ARB staff to check the emissions

calculation as part of their review of these reports. As part of the streamlined approach for reporters in this range, they would not be subject to other regulatory requirements for third-party verification, missing data substitution, or calibration and measurement accuracy. This will minimize costs while providing ARB a means of monitoring what is happening "below the cap" for the cap-and-trade program. This feature of the regulation is part of the WCI design recommendation.

Reporters No Longer Affected. The current ARB reporting regulation requires reporting by power plants and cogeneration facilities emitting between 2,500 and 10,000 metric tons of CO_2e (ARB MRR 2007). These facilities will no longer be subject to reporting requirements. No facility or supplier below 10,000 MT of CO_2e will be required to report to California, except in the unlikely case one is brought in by U.S. EPA whole-sector requirements.

Gases and Processes Included. The proposed revised regulation provides specific reporting requirements for each industrial sector, defining which facility processes and GHGs must be reported. In general, all facilities would be required to report their on-site stationary source combustion emissions of CO_2, N_2O (nitrous oxide), and CH_4 (methane). Some industrial sectors, such as cement, glass production, nitric acid production, and refineries, would also report their process emissions, which occur from chemical or other non-combustion activities. Some facilities would also report fugitive emissions as specified in the proposed regulation. The CO_2 emissions from biomass-derived fuels would be counted toward reporting thresholds, but separately identified during reporting to facilitate their exclusion (in most cases) from a cap-and-trade compliance obligation.

Like the current regulation, the proposal would require that those reporting their direct emissions also provide their consumption of purchased or acquired electricity and thermal energy, which facilitates emissions footprinting and supports ARB energy efficiency regulations. However, current requirements for electricity sector reporting of sulfur hexafluoride (SF_6) and hydrofluorocarbons (HFCs) have been dropped; these compounds are not subject to cap-and-trade and other ARB programs now address them more comprehensively.

Reporting Schedule and Phase-in. The data specified in the proposed revised regulation would be reported to ARB annually. The first emissions reports, for 2011 emissions, would be submitted in 2012. Most reports would be due April 1 of each year. Electric power entities and the lower-emitting facilities and suppliers eligible for abbreviated reporting would report by June 1 of each year. When reporting on 2011 emissions in 2012, facilities and suppliers could report under U.S. EPA reporting requirements if any additional monitoring equipment needed to comply with the revised ARB regulation was not in place in 2011.

Missing Data Provisions. The proposed revised regulation includes requirements for the replacement of emissions and fuel monitoring data. Because the U.S. EPA regulation was not designed for a cap-and-trade program, these additional elements

are intended to prevent abuse of monitoring practices that would undermine fairness in a market program. They are based on similar requirements developed for U.S. EPA market programs, particularly the Acid Rain Program.

Third-party Verification. Most facilities and entities subject to the proposed revised regulation would be required to contract for third-party verification of their submitted emissions data reports to ensure the completeness and accuracy of the data, and to confirm the use of required methods in preparing the emission estimates. Verification would not be required for facilities emitting between 10,000 and 25,000 metric tons of CO_2e that are submitting an abbreviated report. The third-party verifiers, working in teams under the auspices of verification bodies, would be required to meet education, experience, and conflict of interest qualifications specified in the regulation prior to being approved by ARB to verify emissions reports. All verifiers would undergo pre-screening, ARB-approved training, and accreditation to perform verification services.

Verification would be performed annually, with more comprehensive reviews, including site visits, at least once during a three-year compliance period under the cap-and-trade market program. The April 1 reporters would complete verification by September 1 and the June 1 reporters by October 1. Verifier accreditation requirements are not significantly changed from current requirements (most facilities and entities affected by the proposed revised regulation are already subject to third-party verification), but the application of verification services will shift slightly as small power plants drop out of reporting and fuel suppliers come in. The revised regulation also provides for a "qualified positive" verification statement, for reports without material misstatement that have minor nonconformances with the regulation. The revised regulation also strengthens verification requirements for biomass-based fuels.

Additional Items. Other items included in the proposed revised regulation and discussed in this staff report are the detailed quantification and reporting requirements for each industrial sector, and additional detail on proposed requirements for missing data substitution, elements of verification services, verifier accreditation, data confidentiality, and document retention and record-keeping. Table ES-1 below provides a summary of the key requirements proposed, and Section I of this report provides additional background and summary information. More complete descriptions of the proposed regulation's requirements, and issues related to its development, are found in the succeeding sections of this report.

Table ES-1
Summary of Proposed Revised Mandatory GHG Reporting Requirements

Topic/Sector	*ARB Staff Proposal*
Who Reports, What Level, How Often	♦ Facility-level reporting for identified sectors and facilities emitting ≥10,000 metric tons of CO_2e. ♦ No thresholds for refineries, Part 75 electricity generating units, cement, lime, nitric acid, or CO_2 suppliers. ♦ Reporting by fuel and CO_2 suppliers for first time. ♦ Electric power entities, including retail providers, marketers, WAPA, BPA, and DWR, report electricity imports, exports, retail sales, and pump loads, as applicable. ♦ Annual reporting of emissions and data by calendar year, beginning in 2012 on 2011 emissions. ♦ Abbreviated reports for facilities under 25,000 MT CO_2e, using default emission factors ♦ Excludes primary and secondary schools, backup generators, fire suppression equipment, some portable equipment.
Reporting Scope	♦ Stationary combustion emissions. ♦ Specified process and fugitive emissions. ♦ Specified fuel and process inputs; product outputs to support benchmarking for cap-and-trade. ♦ Energy usage--electricity in kWh and thermal in Btu---reported by facilities. ♦ Fuel and CO_2 suppliers report specified sales transactions. ♦ Electric power entities that report imported electricity must report associated specified and unspecified sources as well as emissions, based on ARB calculated emission factors.
General Requirements, Reporting Entities	♦ First-year phase-in allows use of U.S. EPA methods as applicable to the reporting entity in 2012 when 2011 monitoring was not in place. ♦ Measurement devices to be calibrated to ±5 percent. ♦ Settle on chosen monitoring methods by 2013, with some allowance for later improvement. ♦ Designated representative for reporting, consistent with U.S. EPA. ♦ Retain data for 10 years for reporting entities in cap-and-trade. ♦ Changes to Enforcement language to clarify what may constitute a violation.
Gases Reported	♦ CO_2, CH_4 and N_2O reported under the revised regulation. ♦ Other Kyoto gases now reported through other ARB regulations.
Abbreviated Reporting: Facilities Under 25,000 MT of CO2e	♦ Apply default factors for stationary combustion. ♦ Report any process emissions (usually not applicable). ♦ Report fuel use, electricity generation information if applicable.

Topic/Sector		*ARB Staff Proposal*
Verification		♦ Required annually for sources above 25,000 MT CO_2e, and all operators in the cap-and-trade program. ♦ Required annually for electric power entities that are first deliverers in the cap-and-trade program. ♦ Required for biomass-derived fuel to avoid compliance obligations ♦ Will be provided by third-party verifiers that meet ARB accreditation criteria. ♦ Includes a conflict of interest policy. ♦ ARB would continue to play an oversight role in verifications and quality of verifiers. ♦ Consistent with Climate Action Reserve (CAR), The Climate Registry (TCR), the International Standards Organization (ISO) 14064-3, European Union (EU) practices, and proposed WCI requirements
Reporting and Verification Deadlines		♦ Facilities and suppliers report by April 1, verify by September 1. ♦ Electric power entities report by June 1, verify by October 1. ♦ Facilities eligible for abbreviated reports (under 25,000 MT of CO_2e) report by June 1 and are not required to verify.
Missing Data Substitution		♦ Operators would monitor fuel consumption at least weekly to facilitate use of data substitution methods. ♦ Units that report CO_2 emissions using CEMS must substitute missing data according to Part 75 rules for CEMS. ♦ Missing fuel characteristic data are substituted with historical data using a multi-tiered, increasingly more stringent approach. ♦ If the annual total facility-level fuel consumption can be accurately determined, the operator can choose the best available method to estimate missing fuel consumption data at unit-level. ♦ If the annual total facility-level fuel consumption cannot be accurately determined, missing fuel consumption data must be substituted using values correlated with other measured operational parameters or be based on historical data using a multi-tiered, increasingly more stringent approach. ♦ An ARB approved alternative monitoring plan can be used in the event of an unforeseeable breakdown of equipment that is expected to cause missing data rate to exceed 20%. ♦ Sources reporting using CEMS are allowed to temporarily use fuel-based calculation method under unforeseeable equipment breakdown.

Topic/Sector	*ARB Staff Proposal*
Emissions Quantification	♦ Methods based on U.S. EPA GHG reporting rule, with modifications for cap-and-trade consistent with WCI harmonization proposal. ♦ Stationary combustion methods require use of specified Tiers from U.S. EPA based on fuel type. ♦ Sector-specific methods are provided for process emissions from unique facility activities. ♦ Use U.S. EPA-specified standardized methods or other methods approved by consensus-based standards organizations. ♦ All sources can use default CH_4 and N_2O factors, but source testing is an option. ♦ Up to 3 percent of facility emissions may be calculated using *de minimis* methods, not to exceed 20,000 metric tons of $CO2_e$.
Stationary Fuel Combustion Sources	♦ Facilities report CO_2, N_2O, CH_4 emissions using methods according to fuel type. ♦ Facilities burning biomass fuels and specified standardized fuels can apply default emission factors and fuel use data to estimate emissions (Tier 1). ♦ Facilities burning pipeline-quality natural gas would use high heating values (Tier 2). ♦ For fuels with variable carbon content facilities would test for carbon or use continuous measurement systems.
Electricity Generating and Cogeneration Units	♦ For each generating unit, report basic equipment information, fuel consumption by fuel type, weighted average of carbon content or high heat value, and biogenic CO_2 emissions if not already required by the U.S. EPA GHG reporting rule. ♦ Report production, sales, and purchases of electricity and thermal energy if applicable. ♦ Geothermal facilities must calculate annual CO_2 and CH_4 emissions using source specific emission factors derived from an ARB approved measurement plan. ♦ For hydrogen fuel cell generating units, report basic equipment information, fuel/feedstock consumption by fuel type, and provider of fuel/feedstock.
Electric Power Entities	♦ Retail providers and electricity marketers (including WAPA, BPA, DWR, and multi-jurisdictional retail providers) provide information on imported electricity—electricity deliveries and associated emissions—to support determination of allowance obligations for Cap-and-Trade. ♦ Provisions to account for real emissions reductions. ♦ Exported electricity is reported by retail providers and marketers to support ARB GHG Inventory. ♦ Retail providers report retail sales to support calculation of free allowances under Cap-and-Trade; verification not necessary if information deemed not confidential. ♦ WAPA and DWR report additional information to support Scoping Plan Implementation measures and the Renewable Electricity Standard program.

Topic/Sector	*ARB Staff Proposal*
Cement Production	♦ Report based on methods specified in U.S. EPA Mandatory Reporting Rule. ♦ Report process emissions estimated by the clinker-based method from U.S. EPA with plant-specific factors developed at specified intervals or by use of continuous measurement systems (Tier 4).
Petroleum Refineries	♦ Quantification methods are based on the U.S. EPA GHG mandatory reporting rule with WCI modifications incorporated. ♦ Facilities report stationary combustion emissions and process emissions from sources such as catalyst regeneration and coking.
Hydrogen Production	♦ Hydrogen producers report stationary combustion emissions and process emissions using U.S. EPA MRR methods with minor WCI modifications incorporated.
Glass Production	♦ Report based on methods specified in U.S. EPA Mandatory Reporting Rule. ♦ Report process emissions estimated by the carbonate-based method from U.S. EPA using default CO_2 emission factors for carbonate-based raw materials or by use of continuous measurement systems (Tier 4). Not required by current ARB rule but required by U.S. EPA rule. ♦ Incorporated missing data provisions from U.S. EPA with modifications to support cap-and-trade. ♦ In addition to U.S. EPA requirements, report specified process inputs and production outputs to support benchmarking for cap-and-trade.
Lime Manufacturing	♦ Report based on methods specified in U.S. EPA Mandatory Reporting Rule. ♦ Report process emissions estimated by the measured calcium and magnesium oxide content method from U.S. EPA using specified stoichiometric ratios or by use of continuous measurement systems (Tier 4). Not required by current ARB rule but required by U.S. EPA rule. ♦ Incorporated missing data procedures from U.S. EPA with modifications to support cap-and-trade.
Nitric Acid Production	♦ Report based on methods specified in U.S. EPA Mandatory Reporting Rule. ♦ Report N_2O process emissions estimated by the U.S. EPA method using a site-specific N_2O emission factor and production data or by an approved alternative method. Not required by current ARB rule but required by U.S. EPA rule. ♦ Incorporated missing data procedures from U.S. EPA with modifications to support cap-and-trade.
Pulp and Paper Manufacturing	♦ Report based on methods specified in U.S. EPA Mandatory Reporting Rule. ♦ Report process emissions; not required by current ARB rule but required by U.S. EPA rule. ♦ Incorporated missing data provisions from U.S. EPA with modifications to support cap-and-trade. ♦ In addition to U.S. EPA requirements, report specified data to support benchmarking for cap-and-trade.

Topic/Sector		*ARB Staff Proposal*
Iron and Steel Production		♦ Report based on methods specified in U.S. EPA Mandatory Reporting Rule. ♦ Report process emissions; not required by current ARB rule but required by U.S. EPA rule. ♦ Incorporated missing data provisions from U.S. EPA with modifications to support cap-and-trade. ♦ In addition to U.S. EPA requirements, report specified data to support benchmarking for cap-and-trade.
Suppliers of Transportation Fuels		♦ Report based on methods specified in U.S. EPA Mandatory Reporting Rule. ♦ Report CO_2, CH_4, CO_2 from biomass-derived fuels and CO_2e; not currently required by U.S. EPA rule ♦ Expands regulated entities to position holders and enterers to allow for accurate account of fuel combusted in California ♦ Expands regulated entities to producers of biomass-derived fuels to have accurate accounting of all transportation fuels ♦ Expands refinery reporting to include liquefied petroleum gas
Suppliers of Natural Gas and LPG		♦ Report based on methods specified in U.S. EPA Mandatory Reporting Rule. ♦ Report CO_2, CH_4, CO_2 from biomass-derived fuels and CO_2e; not currently required by U.S. EPA rule ♦ Expands regulated entities to interstate and intrastate pipelines ♦ Expands regulated entities to consignees of liquefied petroleum gas ♦ Expands natural gas liquids fractionators reporting to include liquefied petroleum gas
Suppliers of Carbon Dioxide		♦ Suppliers of carbon dioxide report mass of CO_2 captured, extracted, imported and exported.
Oil and Natural Gas Systems		♦ Report based on methods specified in U.S. EPA Draft Reporting Rule: Mandatory Reporting of Greenhouse Gases: Petroleum and Natural Gas Systems ♦ Report process, vented and fugitive emissions not required by current ARB Rule but required by U.S.EPA draft rule.

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I. BACKGROUND AND INTRODUCTION

A. Structure of the Staff Report

This staff report with associated attachments represents the Initial Statement of Reasons (ISOR) for Proposed Rulemaking required by the California Administrative Procedures Act. In this report the Air Resources Board (ARB or Board) staff presents the proposed revisions to the Regulation for the Mandatory Reporting of Greenhouse Gas (GHG) Emissions for California. The revisions to the regulation are necessary to support a California GHG cap-and-trade program and to harmonize with the U.S. Environmental Protection Agency (U.S. EPA) federal mandatory GHG reporting requirements. The staff report describes how the proposal was developed, why we selected the proposed options, and other information as outlined below.

The staff report is divided into the following sections:

- Section I. Background and Introduction – Discussion of regulatory requirements, how the regulatory proposal was developed, and a general overview of the reporting requirements, including requirements for each industrial sector.
- Section II. Greenhouse Gas General Reporting Requirements – Discussion of the general revisions to the regulation, including topics and issues that emerged during regulation development. Biofuel purchases and stationary combustion provisions are covered in this section.
- Section III. Sector Specific Reporting Requirements – Information about the reporting and emission calculation requirements for stationary combustion and specific industrial sectors subject to GHG reporting and how they were developed.
- Section IV. Verification – Discussion of the proposed verification requirements including how emissions data reports are to be verified, the procedure and qualifications for becoming a verifier of emissions data reports or offset project data reports, and the conflict of interest requirements for verifiers.
- Section V. Environmental Impacts of Regulation – Describes what impacts the proposed regulation may have on the environment, including a discussion of potential environmental justice impacts.
- Section VI. Economic Impacts of Regulation – Describes the economic impacts of the proposed regulation.
- Section VII. Alternatives to the Proposed Regulation – Describes other alternatives that were considered for the revisions to the existing GHG reporting regulation and why the alternatives are less effective than the proposed revised GHG reporting regulation.
- Section VIII. Summary and Rationale for Proposed Regulation.
- Section IX. References – Provides a list of references used for development of the staff report.
- Attachments. Attachments include the proposed ARB regulatory text, 40 CFR Part 98 rule sections incorporated by reference, 40 CFR Part 75 as incorporated

by reference, the text of the California Global Warming Solutions Act of 2006, and the federal rules related to the staff proposal.

B. Background

Climate change poses a serious threat to the economic well-being, public health, natural resources, and the environment of California. Global warming is projected to have detrimental effects on some of California's largest industries, including agriculture and tourism, increase the strain on electricity supplies, and contribute to unhealthy air. National and international actions are necessary to fully address the issue of global warming. Action taken by California to reduce emissions of greenhouse gases will have important effects by encouraging other states, the federal government, and other countries to act. By exercising a leadership role, California is also positioning its economy, technology centers, academic and financial institutions, and businesses to benefit from national and international efforts to reduce emissions of greenhouse gases.

The legislature passed and the Governor signed the California Global Warming Solutions Act of 2006 (AB 32, Núñez, Statutes of 2006, chapter 488) (AB 32 or the Act) to exercise this leadership role. Key provisions of the Act required ARB to determine a statewide greenhouse gas emissions level for 1990 and establish a 2020 emissions limit equal to that level, to identify greenhouse gas "early action" reductions, to develop a greenhouse gas emission reductions plan (ARB Scoping Plan 2008) to achieve 1990 GHG levels, to adopt regulatory GHG emission reduction measures, and to adopt regulations to require the reporting and verification of greenhouse gas emissions.

A successful GHG reduction program requires a system to estimate, report, and track GHG emissions, to aid the identification and implementation of emission reduction strategies, and to monitor their effectiveness. Achieving the Act's objectives requires accurate, verified, facility-specific GHG emissions data based on standardized emission estimation methods. The Act therefore required ARB to "adopt regulations to require the reporting and verification of statewide greenhouse gas emissions and to monitor and enforce compliance with this program." Health and Safety Code (H&SC) section 38530(a). In developing a GHG reporting regulation, ARB was charged to:

- Require annual GHG emissions reporting, beginning with the largest emission sources;
- Account for GHG emissions from all electricity consumed in the state, including imports and line losses;
- Strive for consistency with existing and proposed GHG emissions reporting programs;
- Ensure rigorous and consistent emissions accounting, and provide reporting tools and formats that ensure necessary data collection;
- Maintain records of all reported emissions, and meet other requirements.

In December of 2007, the Board adopted the Regulation for the Mandatory Reporting of Greenhouse Gas Emissions (Subchapter 10, Article 2, sections 95100 to 95133, title 17,

California Code of Regulations). Over the past two and a half years, ARB staff have successfully deployed and maintained the GHG reporting program as required by the regulation. This has included identification of facilities subject to reporting, development of a broad array of guidance materials, presentation of many training sessions for reporters and verifiers, the creation of an online GHG emissions reporting tool, establishment of a third-party verification program, and ongoing support to reporters and verifiers.

This existing regulation for the mandatory reporting of GHG emissions, and the data collected, has helped to improve California's GHG emission inventory which provides a mechanism to track emissions trends and support emission reduction strategies. The GHG reporting regulation is a central component of our efforts to quantify, evaluate, and reduce greenhouse gas emissions.

With California now developing a proposed GHG cap-and-trade system, and following the adoption of federal GHG emissions reporting requirements, it is necessary to update the existing California GHG reporting regulation. In addition to the authority provided by AB 32, the authority to adopt the proposed amendments is provided by other provisions of the California Health and Safety Code that are not part of AB 32. The following provisions provide ARB with separate, independent authority to adopt the proposed amendments: sections 39600, 39601, 39607, 39607.4, and 41511 of the Health and Safety Code. Section 39607 requires ARB to inventory sources of air pollution and kinds and quantities of air pollution from these sources. As part of this requirement, Health and Safety Code section 39607.4 requires ARB to "prepare, adopt, and update" the inventory of emissions related to climate change formerly conducted by the State Energy and Natural Resources Conservation and Development Commission pursuant to Chapter 8.5 (commencing with Section 25730) of Division 15 of the Public Resources Code. The amendments to the existing GHG reporting requirements are therefore also necessary to ensure an accurate, updated inventory of GHG emissions in California.

An overview of the approach for making the updates follows.

C. Development of the Regulatory Proposal

Since the adoption of ARB's current GHG reporting regulation in 2007 there have been two important developments. First, as called for in the Board-approved Scoping Plan, ARB staff has moved forward with developing a GHG cap-and-trade system as a mechanism to reduce GHG emissions. Because a GHG cap-and-trade system creates a marketable commodity out of GHG emissions, accuracy of GHG emissions estimation is critically important. ARB staff has to strengthen our current reporting rules to reduce the possibility of incomplete, inconsistent, or inaccurate reporting.

Secondly, in 2009, the U.S. EPA adopted federal requirements for mandatory GHG emissions reporting, as called for in the FY2008 Consolidated Appropriations Act (H.R.

2764; Public Law 110–161).[1] The U.S. EPA reporting requirements are similar in many respects to the existing ARB reporting requirements. In addition to numerous small differences in a rule of its size, the federal rule is broader in scope, bringing in additional industrial sectors and sources of process emissions. The broad scope serves the needs of an economy-wide cap-and-trade program, but as U.S. EPA points out, the federal regulation was not designed to fully support a cap-and-trade program. There are instances where applied methods lack sufficient rigor or would not result in a consistent and accurate emissions estimation by source type. The missing data provisions in the federal regulation are also not strong enough to support a market-based emissions trading system. Moreover, in order to effectively support a cap-and-trade program, there is also a need to retain and enhance a strong verification component for careful review of each emissions report and error correction when needed.

To meet these concerns while developing a regulation that would minimize the duplication of reporting efforts, ARB staff worked to carefully review and evaluate the U.S. EPA regulation and develop harmonized calculation and reporting requirements. Staff undertook a review of the feasibility of aligning the proposed ARB mandatory reporting regulation (ARB MRR 2007) with the new *U.S. EPA Final Rule for the Mandatory Reporting of Greenhouse Gases* (USEPA MRR 2009-2010), starting with discussions with U.S. EPA staff in late 2009. Concurrently, the WCI Reporting Committee was directed by the WCI Partners to harmonize the *WCI Essential Requirements for Mandatory Reporting* (WCI ERMR 2009), which had been developed to support a regional cap-and-trade program, with the U.S. EPA rule, which had not been developed to support cap-and-trade. ARB staff participated in extensive discussions with the other WCI jurisdictions through the WCI Reporting Committee to identify changes or limitations to U.S. EPA MRR requirements that would result in compliance grade emissions calculations for cap-and-trade while minimizing any need to report different numbers than those reported to U.S. EPA. The process resulted in the *Proposed Harmonization of Essential Requirements for Mandatory Reporting* (WCI HER 2010), released by the WCI Partners on May 28, 2010.

By using the U.S. EPA reporting regulation rather than the current ARB regulation as our starting point in writing reporting requirements for cap-and-trade, ARB staff has endeavored to substantially reduce the reporting burden on California reporters by avoiding or minimizing duplicative monitoring and reporting requirements. By working collaboratively with, and sharing expertise among, the WCI jurisdictions, ARB staff was able to efficiently identify which elements of the complex U.S. EPA reporting regulation required revision to support a California and western region cap-and-trade program. The harmonized requirements, to be applied throughout the WCI region, will allow reporters to formulate and submit emissions reports that meet the needs of a cap-and-

[1] The FY2008 Consolidated Appropriations Act mandated that at least $3,500,000 provided in the Environmental Programs and Management account would be provided a rule "to require mandatory reporting of greenhouse gas emissions above appropriate thresholds in all sectors of the economy of the United States." Division F, Title II, Administrative Provisions, Environmental Protection Agency (Including Rescission of Funds) (US Congress 2008)

trade program, and in most cases, satisfy federal reporting requirements without additional work.

Public Outreach. In order to build on the public outreach conducted in the development of the existing GHG reporting regulation,[2] and to help develop the proposed revised regulation and get public feedback, a day-long workshop was held March 23, 2010 to hear from stakeholders and discuss our overall approach and sector specific requirements.[3] Staff discussed the twin goals of aligning with federal requirements and developing a reporting program to support the GHG control program, including proposed cap-and-trade rules. Staff presented current thinking on rule applicability, reporting schedules, *de minimis* emissions, measurement accuracy, missing data procedures, and other topics.[4] Longer sessions presented concepts and current thinking on third party verification, methods for stationary combustion and process emissions sources, reporting by electricity first deliverers, and reporting by fuel suppliers.[5] Extensive comments were received during and in the weeks following the workshop. Staff considered each comment carefully as regulatory language was developed through the course of the spring and summer.

In addition to the spring workshop, staff met in person and by teleconference numerous times with stakeholders. Often these meetings grew out of discussions on implementation of the current regulation as reporting entities worked to complete their second year of reporting and first year of verification. Where implementation challenges have arisen, staff has used the opportunity of the regulation revision to consider lessons learned, and applied them in this regulatory proposal. ARB staff and reporters have been working with an established regulation and have learned much through the first two years of the reporting program. Because of this experience and the mutual desire to support alignment with federal requirements -- themselves developed through a public process -- stakeholders have said they prefer that the ARB and U.S. EPA rule be as consistent as possible to simplify reporting.

ARB staff also participated in the U.S. EPA training session on federal reporting held May 4, 2010, in Los Angeles. Staff discussed our effort to align the requirements of the ARB regulation with U.S. EPA's requirements when modifying the regulation to support cap-and-trade, and answered questions on the regulation and this approach. Staff also participated in stakeholder discussions organized by WCI to hear comments in

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[2] In developing the existing GHG reporting regulation, ARB staff conducted five workshops and met multiple times with individual stakeholders to discuss various aspects of GHG reporting. Staff also responded to comments submitted prior to taking the existing regulation to the Board, and during the 45-day comment period, as well as two 15-day comment periods. *See* Staff Report: Initial Statement of Reasons (ARB ISOR 2007), page 3, *see also* Final Statement of Reasons, Including Summary of Comments and Agency Responses (ARB FSOR 2008).

[3] Notice for the March 23, 2010 Workshop to Discuss Revisions to the California Mandatory Greenhouse Gas Reporting Regulation (ARB Wkshp Notice 2010)

[4] ARB Staff Workshop Slides, Workshop to Revise ARB's Mandatory Greenhouse Gas Reporting Regulation, March 23, 2010 (ARB Wkshp Slides Gen 2010)

[5] ARB Staff Workshop Slides, Combustion and Industrial Sectors (ARB Wkshp Slides Cmb 2010); Electricity Deliverers (ARB Wkshp Slides Elec 2010); and Fuel Suppliers (ARB Wkshp Slides Fuel 2010).

response to the *Proposed Harmonization of Essential Requirements for Mandatory Reporting* (WCI HER 2010).

Basic Approach. To accomplish harmonization within the confines of California rulemaking processes, the proposed regulation is somewhat unique in its approach. In order to ease confusion for reporters and to help ensure good data quality, the proposed regulation directly references the U.S. EPA requirements, telling reporters where they must comply with specific applicable sections of the federal rule to meet ARB requirements. We then stipulate any needed limitations, modifications, or additions to the federal requirements where necessary to support California's cap-and-trade program. A typical lead-in paragraph for a section is provided below as an example:

> The operator of a facility who is required to report under section 95101 of this article, and who is not eligible for abbreviated reporting under section 95103(a), must comply with Subpart AA (40 CFR §§98.270 to 98.278) in reporting annual emissions to ARB except as otherwise provided in this section.

The remainder of the section then describes what additional ARB requirements must be met. This may include, as examples, the exclusion of an estimation method that lacks sufficient rigor, and the inclusion of requirements for what the reporter must do if key measurement data are missing.

Thus, a California reporter will essentially comply with the federal requirements, but in some cases will need to use more rigorous methods to provide data that is of cap-and-trade quality. This means most reporters will need to be familiar with the U.S. EPA regulations – and usually already will because it is a rule that affects them directly. They will then need to become familiar with any California reporting differences specified in the revised ARB regulation. By structuring our regulation such that it incorporates specific provisions of the U.S. EPA rule while concisely listing differences, we have tried to make the reporting process in California as straightforward and transparent as possible.

Note that U.S. EPA continues to modify its own regulation. ARB staff has reviewed the modifications finalized by U.S. EPA as of October 7, 2010, and included these changes in the staff proposal. Additional U.S. EPA rulemakings, and their consistency with the needs of the cap-and-trade program, will be considered later. The complete text of the U.S. EPA regulation is available at: http://www.epa.gov/climatechange/emissions/ghgrulemaking.html. (USEPA MRR 2009-2010). Table I-1 below is intended to help the reader refer to similar requirements in both regulations.

Lower-emitting Facilities. The U.S. EPA rule applies a reporting threshold of 25,000 metric tons of CO_2e to most types of facilities. The WCI design framework includes monitoring emissions below the thresholds associated with a cap-and-trade compliance obligation, which is also 25,000 MT of CO_2e. Consistent with the WCI decision, this

regulatory proposal includes a reporting threshold of 10,000 metric tons of CO_2e for the facilities with a federal reporting threshold. (This is the level of emissions associated with burning about 180 million standard cubic feet of natural gas, or 1.85 million therms.) ARB staff has worked to minimize this new reporting burden for facilities beneath the cap by developing simplified reporting requirements for those facilities. This abbreviated reporting option for smaller facilities is intended to cut through the complex federal reporting rules applied to facilities emitting over 25,000 metric tons of CO_2e. The abbreviated reporting requirements are found in section 95103(a) of the regulatory proposal. Fuel sampling and testing are not required for these facilities, though they may choose to apply those options if they are close to the cap-and-trade emissions threshold. Most will choose default emission factors and report at a relatively low cost.

Table I-1. Cross-Reference Between Proposed ARB Mandatory Reporting Regulation Revision and Related U.S. EPA Reporting Requirements

Topic or Industrial Sector	***ARB MRR Section***	***40 CFR Part 98 Sections***
Purpose and Scope	95100.5	98.1
Applicability	95101	98.2
Definitions	95102	98.6
Greenhouse Gas Reporting Requirements	95103	98.3, 98.4
Greenhouse Gas Emissions Data Report	95104	98.3, 98.5
Document Retention and Record Keeping	95105	98.3 (g)
Enforcement	95107	98.8
Standardized Methods	95109	98.7
Cement Production	95110	98.80-88
Electric Power Entities	95111	n/a
Electricity Generation and Cogeneration	95112	98.30-38, 98.40-48
Petroleum Refineries	95113	98.250-258
Hydrogen Production	95114	98.160-168
Stationary Fuel Combustion Sources	95115	98.30-38
Glass Production	95116	98.140-148
Lime Manufacturing	95117	98.190-198
Nitric Acid Production	95118	98.220-228
Pulp and Paper Manufacturing	95119	98.270-278
Iron and Steel Production	95120	98.170-178
Suppliers of Transportation Fuels	95121	98.390-398
Suppliers of Natural Gas, Natural Gas Liquids, and Liquefied Petroleum Gas	95122	98.400-408
Suppliers of Carbon Dioxide	95123	98.420-428
Petroleum and Natural Gas Systems	95150-95158	Proposed 98.230-238
Substitution for Missing Data Used to Calculate Emissions from Stationary Combustion and CEMS Sources	95129	98.35
Verification of Emissions Data Reports and Verifier Accreditation	95130-95133	98.3(f)

D. Proposed Revised Regulation – A Summary

1. Objectives of the Proposed Regulatory Action

The purpose of this proposed revised regulation is to meet the requirements of AB 32 to develop a comprehensive and effective mandatory GHG reporting program for California. The revisions provide needed updates to support the ARB cap-and-trade program and other programs. It also harmonizes most California reporting requirements with the U.S. EPA reporting requirements to simplify and streamline GHG emissions reporting. Our primary objectives have included: requiring reporting for the most significant GHG emissions sources, using rigorous and consistent emission accounting methods, providing for third-party verification of reported data, and harmonizing with U.S. EPA and WCI GHG reporting requirements.

2. Overview of General Requirements

The proposed revised GHG reporting regulation includes annual emissions reporting from facilities, fuel suppliers, and electric power entities that account for approximately 87 percent of California's total CO_2e emissions from all sources. The addition of new industrial process emissions categories, new reporting by suppliers of natural gas and transportation fuels, and the reporting of emissions (not just transactions) by electricity importers all extend the emissions coverage of the regulation.

Like the federal regulation, the staff proposal requires facilities to consider their emissions from process emissions sources, in addition to combustion emissions. These industrial process sources, which occur from chemical or other non-combustion activities, include emissions from glass production, lime manufacturing, nitric acid production, pulp and paper manufacturing, and iron and steel production. Staff is also proposing process emissions reporting from petroleum and natural gas systems sources included in the U.S. EPA's proposed Subpart W rule, scheduled for inclusion in the federal reporting requirements in the Fall of 2010. These industrial process source categories are proposed as additions to those process sources included in the current ARB regulation, including cement production, power plants, petroleum refineries, and hydrogen plants.

Gases and Basic Requirements. The proposed regulation provides detailed reporting specifications for each industrial sector, defining which facility processes and GHGs must be reported. In general, all facilities report their on-site stationary source combustion emissions of carbon dioxide (CO_2), nitrous oxide (N_2O), and CH_4 (methane). The CO_2 emissions from biomass-derived fuels would be separately identified during reporting.

The industrial sectors mentioned above would also report specified process emissions of these same gases, which occur from chemical or other non-combustion activities. Facilities report fugitive emissions when specified in the regulation.

Particular California requirements apply to the electric power sector to meet the requirements of AB 32 and the needs of the proposed cap-and-trade program. Retail providers and marketers who import or export electricity would report specified electricity transactions and calculate emissions associated with them.

All reporters would provide certain specified information including:

- California-specific information such as ARB identification number, air district, air basin, and geographic location;
- A designated reporting representative, as required by U.S. EPA;
- Specified information on the entity's corporate parent and NAICS codes, as currently proposed by U.S. EPA;
- Consumption of purchased electricity and thermal energy, and the provider of that energy. Such information is usually not difficult for reporters to compile and is important for the implementation of certain GHG control programs, including the energy audits regulation and the proposed cap-and-trade regulation.

Reporters would be required to retain records associated with their emissions reports for a period of ten years when they are associated with a cap-and-trade compliance obligation, and five years when they are not. This is to assure that any question that comes up about a past report can be resolved, particularly if it involves a compliance obligation.

Reduced Burden. The proposed regulation would also relieve the current reporting burden from certain facilities as follows:

- Power plants that emit below 10,000 metric tons of CO_2e would no longer be required to report; the current reporting threshold is 1 megawatt and 2,500 metric tons of CO_2e.
- Retail providers would no longer be asked to report a range of data that would have been needed had a load-based point of regulation been developed for the electricity sector.
- Facilities and entities would no longer be required to report sulfur hexafluoride (SF_6) and hydrofluorocarbon (HFC) emissions; other ARB regulations now cover this requirement more comprehensively and a duplicative requirement here is unwarranted.
- Fugitive emissions of CH_4 from coal storage would no longer be required in reporting by cement and power plants; these very small emissions are highly uncertain and not needed for ARB's control programs.

Reporting Responsibility. The U.S. EPA regulation refers to facility "owners and operators" or "owners or operators" as responsible for submitting the emissions report. The ARB staff proposal clarifies that where the owner and operator of a facility are not the same, the operator has the responsibility for compliance. The

operator is defined as having operational control over a facility. For this proposal, as for the current ARB reporting regulation, operational control means the authority to introduce and implement operating, environmental, health and safety policies. Where such responsibilities are shared, the party holding the air quality permit is considered to have operational control.

Suppliers of fuels and industrial gases, including producers, importers, and exporters, report to U.S. EPA. Suppliers of fuels and CO_2 would also report to ARB, but some additional entities are specified as suppliers to allow products exported from California to be excluded, and other specified products to be included. The additional entities in the supplier category include position holders at terminal racks and refineries, enterers of petroleum products and biofuels, biofuel producers not already reporting to ARB, and consignees of liquefied petroleum gas. Local distribution companies, pipeline operators and natural gas fractionators would also report to ARB as fuel suppliers. Producers and importers of carbon dioxide report to ARB, but like fuel suppliers, may exclude products destined for export from California.

Importers and exporters of electricity also report to ARB. This includes California and multijurisdictional retail providers, power marketers, the Western Area Power Administration, and the California Department of Water Resources. Retail providers currently reporting electricity transactions and retail sales to ARB will only report retail sales, if they are not importing or exporting power.

Electricity generating facilities that are solely powered by nuclear, hydroelectric, wind or solar energy electricity generating sources would not be required to report under the proposed revised regulation, unless they have sufficient stationary combustion onsite to meet the reporting thresholds of the regulation. Backup generators and fire suppression equipment are excluded, as is portable equipment at most types of facilities. Primary and secondary schools would still not have to report. Hospital would now be required to report when they have combustion emissions exceeding 10,000 metric tons of CO_2e; some have significant power generation onsite and offer power to the grid.

ARB staff estimates that approximately 750 emitting facilities, suppliers and entities would be subject to GHG reporting under the proposed revised regulation, compared to about 600 currently (ARB GHG Summary 2010, ARB CEIDARS 2007). Given that various facilities, suppliers, and entities are under common ownership staff estimates that this equates to approximately 450 businesses (ARB GHG Summary 2010, ARB CEIDARS 2007).

Reporting and Verification Schedule. The proposed revised regulation, like the current one, requires facilities subject to reporting to submit an emissions data report annually to ARB. Emissions data reports would be submitted for the previous calendar year. Staff is again proposing a bifurcated reporting schedule, with April 1 and June 1 deadlines. The April 1 deadline would apply to facility operators and

fuel/CO_2 suppliers. The June 1 deadline would apply to electric power entities. Operators who do not report to U.S. EPA and have no cap-and-trade compliance obligation (facilities under 25,000 metric tons of CO_2e) may also report by the June 1 deadline.

Annual third-party verification by accredited verification bodies would be required for all reports of emissions that equal or exceed 25,000 metric tons of CO_2e. Facility operators and suppliers must complete verification by September 1 of each calendar year, and electric power entities by October 1.

Phase-in Year. ARB staff proposes a one-year phase-in period to allow facilities and suppliers who have not previously reported GHGs to ARB, and are not required to report GHGs to U.S. EPA, to develop monitoring systems, train personnel in data collection, and install any necessary equipment. The first emissions data reports under the proposed revised regulation, for 2011 emissions, would be submitted in 2012. Facilities and suppliers would be permitted to report on 2011 emissions using only the requirements in the U.S. EPA regulation (USEPA MRR 2009-2010). This approach recognizes that any changes in monitoring methods necessitated by new California requirements will not be immediately effective in 2011, and provides time for facilities and suppliers to accommodate them. All future emissions reports would need to fully comply with specified calculation requirements.

Cessation of Reporting. Similar to U.S. EPA requirements, reporting entities would be entitled to cease reporting once emissions drop below specified thresholds for an extended period. The cessation thresholds are different because the reporting threshold is different: reporting may cease after five years below 10,000 metric tons of CO_2e, or three years below 5,000 metric tons CO_2e. In cases of facility shutdown or modification that eliminates GHG emissions, reporting may cease after one year of reporting zero emissions.

Non-submitted/Non-Verified Emissions Data Report. In the event a reporting entity fails to submit an emissions data report or fails to get an emissions data report verified by the applicable deadline, the Executive Officer will calculate an assigned emissions level for that reporting entity. The Executive Officer will evaluate several factors in developing that assigned emissions level. The facility number calculated by the Executive Officer becomes the reporting entity's obligation under the cap-and-trade program.

Missing Data Provisions. Many of the provisions for missing data substitution in the U.S. EPA reporting rule could potentially be subject to abuse in a cap-and-trade system. To address these concerns, the proposed rule requires the operators to follow these procedures in substituting for missing data:

For 40 CFR Part 75 units, follow 40 CFR Part 75 (revised as of July 1, 2009) missing data substitution procedure. (This is consistent with U.S. EPA reporting rule requirement). For non-Part-75 units that report CO_2 emissions using a continuous

emissions monitoring system (CEMS), substitute missing data according to 40 CFR Part 75 rules for CEMS.

For missing fuel characteristic data (heat value, carbon content, moisture content, and molecular weight), apply an increasingly more conservative substitution method based on percent data capture rate. At a capture rate above 90%, use the U.S. EPA approach in Part 98. At a capture rate below 90%, substitute the missing value with the highest value recording during specified lookback periods.

For missing fuel consumption data, the operator has leeway in selecting the best available estimate method as long as the annual total facility-level fuel consumption can be accurately determined. In the rare instances where annual fuel use cannot be accurately determined, missing fuel consumption data must be filled with values that can either be correlated with other measured operational parameters or be based on the actual fuel use values under usual operating conditions. (See Section II.C for additional discussions.)

In the event of an unforeseeable breakdown of equipment that is expected to cause a missing data rate of more than 20%, operators meeting certain criteria can use an alternative monitoring plan approved by ARB. Sources reporting using CEMS are allowed to temporarily use a fuel-based calculation method if certain criteria are met.

Miss data elements cumulatively causing more than 80% of emissions to not be directly calculated from measure parameters is an automatic nonconformance, even if the operator has correctly followed all the missing data substitution procedures in the rule.

Other General Provisions. The proposed regulation retains, with some modifications, current requirements regarding *de minimis* emissions. U.S. EPA requirements for calibration or measurement equipment are included in the proposal, with an additional stipulation that ARB is notified about, and can approve, delays in calibration. Other items included in the proposed general requirements are definitions, specifications for claiming confidential data, and language on enforcement of the regulatory provisions. With rare exceptions, and in order to avoid inconsistent interpretations, the proposed definitions are fully consistent with definitions in the U.S. EPA regulation. Definitions have been added for the provisions of this regulatory proposal not covered by federal reporting requirements.

3. Overview of Requirements for Stationary Fuel Combustion Sources

Stationary Fuel Combustion Sources. This component of the regulation applies to multiple industrial sectors, and includes devices that combust solid, liquid, or gaseous fuels, generally for the purposes of generating steam, producing electricity, providing useful heat or energy for industrial, commercial, or institutional use, or reducing the volume of waste by removing combustible matter. Stationary sources include, but are not limited to, boilers, simple and combined-cycle combustion turbines, engines, incinerators, and process heaters. This is the most important single source category as it is present at almost every facility.

The proposed revised regulation specifies reporting requirements and methods to calculate CO_2, CH_4, and N_2O by fuel type. The proposal is based on the U.S. EPA's tiered series of combustion methods, with limitations applied by fuel type to ensure a high degree of accuracy. Use of the lower-tier methods is limited to pipeline quality natural gas and standardized liquid fuels. Carbon testing or use of CEMS is required for other fuels due to the likelihood of variable carbon content. Additional specifications are proposed for CEMS CO_2 monitoring.

As in the current ARB regulation, only units combusting biomass or municipal solid waste could apply the Tier 2 steam production method. The proposal would also continue the daily sampling of refinery fuel gas that is required in the current reporting regulation, and site-specific emission factors derived from source testing are again provided as an option for CH_4 and N_2O emissions.

4. Overview of Requirements for Electric Power Entities

Electric power entities are required to continue reporting imported electricity, exported electricity, and retail sales, as applicable. In the revised proposed regulation, electric power entities will now also report emissions associated with imported and exported electricity, pursuant to the methods provided. Reported emissions associated with imported electricity will inform the cap-and-trade program compliance requirement for first deliverers of electricity to hold allowances. Retail sales data are needed to inform the allocation of free allowances for retail providers. Exported electricity is reported for ARB inventory purposes. ARB is continuing to require retail providers to report out-of-state facility ownership share and contracts in order to evaluate whether anticipated decreases in future imported electricity emissions are due to resource shuffling or real emissions reductions in the western regional power system due to California's cap-and-trade program.

The proposed revisions include a new requirement that the Western Area Power Administration (WAPA) report pump loads for the Central Valley Project, as well as maintaining the requirement that the California Department of Water Resources (DWR) continue to report its State Water Project pump loads. These requirements will support future analysis of GHG implications of water conservation and efficiency measures. DWR and WAPA are also included as regulated entities in the proposed Renewable Electricity Standard (RES) regulation (*see* proposed title 17, *California Code of Regulations,* section 97000 et al.). ARB staff is currently assessing mechanisms to allow DWR and WAPA the option of satisfying RES reporting requirements through the mandatory GHG reporting regulation and may propose 15-day changes to the currently proposed regulation.

Two reporting requirements of the current regulation (ARB MRR 2007) have been removed: (1) out-of-state facilities are no longer required to obtain verification of their emissions data reports, and (2) reporting wholesale electricity purchases and sales from California sources for electricity that is consumed in California is no longer required.

5. Overview of Reporting Requirements for Industrial Facilities

Cement Production. The proposed ARB reporting requirements are drawn from and similar to the U.S. EPA greenhouse gas reporting requirements for cement production facilities. The propose ARB regulation would affect eleven California plants, which are also subject to the U.S. EPA reporting rule for greenhouse gases. All California cement plants would be required to report combined process-related and combustion CO_2 emissions from clinker production using the CEMS methodology or separately report combustion emissions and process-related CO_2 emissions. When separately reporting combustion emissions, cement plants would be required to report emissions of CO_2, biomass-derived CO_2, CH_4, and N_2O from kiln and other combustion sources by using fuel-specific methods, which may involve carbon or heat value testing. When separately reporting process-related emissions from clinker production, cement plants would be required to follow the regulation's specified clinker-based methodology and to also report process-related emissions from the organic carbon entrained in non-carbonate raw materials consumed. In addition, facilities would report quantities of fuel used, fuel characteristics, quantities of raw material consumed, annual clinker production, and other supporting data to allow ARB to calculate efficiency metrics and support benchmarking for the cap-and-trade program.

Electricity Generating and Cogeneration Units. The proposed ARB reporting requirements are drawn from and similar to the U.S. EPA greenhouse gas reporting requirements for electricity generation and cogeneration facilities. The proposed ARB regulation would affect approximately 150 electricity generating facilities and about 130 facilities with cogeneration units. About a third of the cogeneration units are stand-alone generating facilities and the remainder are included as part of another reporting facility. Operators of electricity generating and cogeneration units emitting 10,000 metric tons of CO_2e per year or more would be required to report emissions of CO_2, biomass-derived CO_2, CH_4, and N_2O, using methods that are specified in the proposed regulation. Facilities emitting 25,000 metric tons of CO_2e per year or more would be required to choose a calculation method tied to fuel type for combustion emissions, which may involve carbon or heat value testing, or use of CEMS if present. Facilities below 25,000 metric tons of CO_2e per year would usually apply default emission factors.

In addition to the U.S. EPA core requirements, the ARB proposal requires reporting of additional descriptive information such as nameplate generating capacity and power generated; providing cogeneration descriptive information such as whether the unit uses topping or bottoming cycle and its thermal output; and applying additional specific missing data procedures that are required for all reporting facilities. The staff proposal would also require reporting of CO_2 and CH_4 by geothermal facilities based on emission factors obtained from source testing.

Petroleum Refineries. The proposed revised regulation is based on the U.S. EPA reporting regulation. This regulation would affect all California petroleum refineries where annual GHG emissions equal or exceed 10,000 MT of CO_2e. Methodologies are

included for the calculation of GHG emissions from the following sources: stationary combustion, flares, catalytic cracking and fluid coking units, flexicoking units, catalytic reformers, sulfur recovery units, coke calcining units, asphalt bowing, delayed coking units, process vents, uncontrolled blowdowns, equipment leaks, and storage tanks. Refiners would also be required to report amounts of CO_2 captured and transferred off-site. Facilities that distill transmix are exempt from reporting.

Proposed changes from the existing ARB reporting rule include new methods for uncontrolled blowdowns and coke calcining, and removal of methods for fugitive emissions from wastewater treatment and oil/water separators. The two methods to be dropped are very minor sources with large uncertainties. The proposed rule also includes several changes that were deemed necessary to provide the requisite accuracy and consistency for a cap-and-trade program. Product output data would also be reported to support benchmarking for the cap-and-trade program.

Hydrogen Production. The proposed revised regulation will affect all hydrogen production facilities in California where GHG emissions equal or exceed 10,000 MT CO_2e annually, whether stand-alone merchant facilities or production units within larger facilities. Operators are required to report stationary combustion and process emissions as well as amounts of CO_2 captured and transferred off-site.

The proposed rule includes modifications to the U.S. EPA regulation that are necessary to ensure that the data reported are compliance grade for emissions trading. Operators would be required to sample feedstocks (other than natural gas) daily, but solid and liquid samples could be composited to produce a monthly sample for carbon content analysis.

Glass Production. The proposed ARB reporting requirements are drawn from and similar to the U.S. EPA greenhouse gas reporting requirements for glass production facilities. The proposed ARB regulation would affect approximately twelve California glass manufacturing facilities, which are also subject to the U.S. EPA reporting rule for greenhouse gases. Glass production facilities emitting 10,000 metric tons of CO_2e per year or more would be required to report emissions of CO_2, biomass-derived CO_2, CH_4, and N_2O from general combustion sources, biomass fired combustion units, and continuous glass melting furnaces using methods that are specified in the proposed regulation. Facilities would be required to report combined process-related and combustion CO_2 emissions from glass production using the CEMS methodology or separately report combustion emissions and process-related CO_2 emissions from glass production using the methods specified in the regulation. When separately reporting combustion emissions, glass production facilities would be required to follow fuel-specific methods, which may involve carbon or heat value testing. In addition, the facility would report quantities of fuel consumed, fuel characteristics, quantities of carbonate-based raw materials consumed, and annual production quantities of glass products to supporting benchmarking for the cap-and-trade program.

Lime Manufacturing. The proposed ARB reporting requirements are drawn from and similar to the U.S. EPA greenhouse gas reporting requirements for lime manufacturing facilities. The proposed ARB regulation is expected to affect a single lime plant in California that is also subject to the U.S. EPA reporting rule for greenhouse gases. It would be required to report combined process-related and combustion CO_2 emissions from the production of lime, calcined lime byproduct/waste that was sold, and calcined lime byproduct/waste that was not sold using the CEMS methodology or separately report combustion emissions and process-related CO_2 emissions from lime products and byproducts using the lime-based method specified in the regulation. When separately reporting combustion emissions, the lime plant would be required to report emissions of CO_2, biomass-derived CO_2, CH_4, and N_2O from lime kiln and other combustion sources by using fuel-specific methods, which may involve carbon or heat value testing. In addition, the facility would report quantities of fuel used, fuel characteristics, quantities of raw material consumed, annual production quantities for lime product, calcined lime byproduct/waste that was sold, and calcined lime byproduct/waste that was not sold, and other specified data.

Nitric Acid Production. The proposed ARB reporting requirements are drawn from and similar to the U.S. EPA greenhouse gas reporting requirements for nitric acid production facilities. The proposed ARB regulation would affect two California nitric acid production facilities, which are also subject to the U.S. EPA reporting rule for greenhouse gases. All California nitric acid production facilities would be required to report process-related N_2O emissions and combustion CO_2 emissions from the production of nitric acid. When reporting combustion emissions, the nitric acid plant would be required to report emissions of CO_2, biomass-derived CO_2, CH_4, and N_2O combustion sources by using fuel-specific methods, which may involve carbon or heat value testing. In addition, the facility would report quantities of fuel consumed and fuel characteristics. Nitrous oxide emissions would be reported using a site-specific emissions factor and production rate data or the operator may request approval from ARB's Executive Officer to use an alternative method, such as the use of N_2O CEMS, for determining nitrous oxide emissions. Annual nitric acid production data and other specified data would also be reported.

Pulp and Paper Manufacturing. The proposed ARB reporting requirements are drawn from and similar to the U.S. EPA greenhouse gas reporting requirements for pulp and paper facilities. The proposed ARB regulation would affect the five California pulp and paper facilities currently reporting, which are also subject to the U.S. EPA reporting rule for greenhouse gases. In addition, four to six additional facilities will likely be subject to abbreviated reporting due to the lower ARB reporting threshold. Pulp and paper manufacturing facilities emitting 10,000 metric tons of CO_2e per year or more would be required to report emissions of CO_2, biomass-derived CO_2, CH_4, and N_2O from general combustion sources, biomass fired combustion units, chemical recovery furnaces/combustion units, and pulp mill lime kilns, using methods that are specified in the proposed regulation. Facilities emitting 25,000 metric tons of CO_2e per year or more would be required to choose a calculation method tied to fuel type for combustion emissions, which may involve carbon or heat value testing, or use of CEMS if available.

Pulp and paper facilities would also be required to report CO_2 process emissions from makeup chemicals, if present. In addition, facilities would report quantities of fuel used, spent liquor solids combusted, fuel characteristics, quantities of $NaCO_3$ and $CaCO_3$ used, and annual production data to support benchmarking for the cap-and-trade program.

Iron and Steel Production. The proposed ARB reporting requirements are drawn from and similar to the U.S. EPA greenhouse gas reporting requirements for iron and steel production. The specific iron and steel reporting requirements proposed would affect only one California iron and steel facility, which is also subject to the U.S. EPA reporting rule for greenhouse gases. Other California steel facilities emitting 10,000 metric tons of CO_2e per year or more, such as those which produce rolled steel, pipe, or forgings, would also be subject to greenhouse gas reporting as a result of their general combustion emissions, but they would not be subject to the additional requirements for reporting process emissions. As proposed, an iron and steel production facility with specified sources and emitting 10,000 metric tons of CO_2e per year or more would be required to report emissions of CO_2, biogenic CO_2, CH_4, and N_2O from combustion sources. Facilities emitting 25,000 metric tons of CO_2e per year or more would be required to choose a calculation method tied to fuel type for combustion emissions, which may involve carbon or heat value testing, or use of CEMS if available. An iron and steel facility would compute and report process emissions from any electric arc furnace (EAF), argon-oxygen decarburization vessel, direct reduction furnace, or other specified sources. Iron and steel facilities would also be required to report annual production information and other specified data to support benchmarking for the cap-and-trade program.

6. Overview of Requirements for Fuel and CO_2 Suppliers

Suppliers of Transportation Fuels. The proposed revised regulation will affect all suppliers of transportation fuels in the State of California where annual amounts of supplied, produced or imported fuel, when completely combusted or oxidized, equals or exceeds 10,000 metric tons carbon dioxide equivalent. The proposed revised regulation will also affect all refiners that produce liquefied petroleum gas without regard to quantity. This requirement includes position holders, enterers, producers of biomass-derived fuels and refiners. In the current ARB regulation refiners are only required to report combustion and process emissions and not emissions from produced fuel combustion, none of the other listed entities are required to report. U.S. EPA methods are used for calculating emissions from all fuels.

Suppliers of Natural Gas, Natural Gas Liquids and Liquefied Petroleum Gas. The proposed revised regulation will affect all suppliers of natural gas, and consignees who import liquefied petroleum gas (LPG) into California where annual amounts of supplied or imported fuel, when completely combusted or oxidized, equals or exceeds 10,000 metric tons of CO_2e. The proposed revised regulation will also affect all natural gas liquid fractionators without regard to quantities supplied. This requirement includes operators of interstate and intrastate pipelines, local distribution companies who are public utility gas corporations or publicly-owned natural gas utilities, liquefied petroleum

gas consignees that import LPG into California, and natural gas liquid fractionators. In the current ARB regulation, natural gas liquid fractionators and public utility gas corporations are only required to report combustion and process emissions from stationary sources and not emissions from supplied fuel combustion, none of the other listed entities are required to report. U.S. EPA methods are used for calculating emissions from all fuels.

Suppliers of Carbon Dioxide. The proposed revised regulation will affect all suppliers of carbon dioxide in California where amounts of produced or imported CO_2 annually equal or exceed 10,000 metric tons. This requirement includes facilities which capture and transfer a CO_2 stream for commercial applications, facilities with CO_2 production wells, and importers and exporters of bulk CO_2. In the current ARB regulation only petroleum refineries with hydrogen production facilities and merchant hydrogen plants were required to report transferred CO_2. U.S. EPA methods are included for facilities where CO_2 is produced and captured (i.e. hydrogen production facilities) and for bulk importers and exporters of CO_2. Operators must also report the quantity of CO_2 transferred for thirteen end-use applications (i.e. food and beverage, pulp and paper) if known. Separate reporting of quantities imported into or exported from California is required under the staff proposal.

7. Overview of Requirements for Petroleum and Natural Gas Systems

The ARB staff proposal is based on the proposed U.S. EPA Subpart W draft rule for Petroleum and Natural Gas Systems and would affect all petroleum and natural production operations in California where an entity's emissions equal or exceed 10,000 metric tons of CO_2e annually within a geologic basin. GHG emissions would be reported for:

- Offshore petroleum and natural gas production;
- Onshore petroleum and natural gas production;
- Onshore natural gas processing plants;
- Onshore natural gas compression;
- Underground natural gas storage;
- Liquefied natural gas (LNG) storage;
- LNG import and export equipment;
- Natural gas distribution.

The draft U.S. EPA Subpart W rule was evaluated and modified by WCI where it was determined that changes were necessary to ensure data generated was cap-and-trade quality, to correct errors, and to provide more workable methodologies. When the U.S. EPA Subpart W Rule is made final, ARB will reconfigure this article to conform with the existing California MRR format.

In the case of onshore petroleum and natural gas production, the reporting footprint is defined as the geological basin. Reporters would be required to determine and report emissions from stationary combustion, and specified process and vented emissions. Under the current ARB reporting regulation, these facilities are required to report only

stationary combustion emissions if they equal or exceed a 25,000 metric tons of CO_2 threshold.

The WCI harmonization process resulted in recommendations that seven of the draft U.S. EPA methodologies be adopted without changes. For several source categories (storage tanks, field gas combustion, and venting of pneumatic devices and pumps) the staff proposal includes changes in methods, and added monitoring equipment to support them. These changes were recommended because WCI concluded that the proposed U.S. EPA methodologies would not generate compliance-grade data to support cap-and-trade. The proposal also includes several minor changes to correct errors in calculation methodologies and improve data quality to a level appropriate for a cap-and-trade program. In addition, two of the U.S. EPA reporting methodologies were not included in the staff proposal because of source insignificance or the decision to propose a more accurate method for the source category.

8. Overview of Verification Requirements

A key element of a credible GHG emissions reporting program is independent verification of the reported emissions to ensure the completeness and accuracy of the emissions estimates and conformance to the regulation. Under the proposed regulation, verification would continue to be performed by qualified, trained, and ARB-accredited third-party verifiers that meet specifications for education and experience, and demonstrate that there is no conflict of interest for verifying the emissions data report due to current or previous relationships with the reporting entity. All verifiers would have to demonstrate knowledge of the proposed regulation to provide verification services for California's mandatory GHG reporting program to support the cap-and-trade program.

Only an ARB-accredited verification body may submit a verification statement on behalf of a reporting entity. Each accredited verification body must have at least two lead verifiers and five total staff. ARB currently has about 230 accredited verifiers and 45 accredited verification bodies. New lead verifiers, general verifiers, sector specific verifiers, and verification bodies will be trained and accredited as needed. The current reporting regulation allows local air quality management districts and air pollution control districts (local districts) to apply for accreditation as verification bodies. ARB staff is continuing to work with local districts to better define the process that allows local districts to provide verification services.

Elements of verification as proposed in the regulation include (1) site visits during the first year of verification to ensure that all required emission sources and processes within the defined facility boundaries are included in the emissions estimates and that the emissions report is complete, (2) development of a plan for specific verification activities, including site visits and document reviews, (3) development of a sampling plan to conduct data checks on the reported emissions, that considers source contributions with the highest emissions and greatest uncertainty, and (4) a verification statement submitted to ARB and the reporting

entity. These and other elements of verification services are discussed in detail in Section IV of this report.

II. GREENHOUSE GAS GENERAL REPORTING REQUIREMENTS

This section includes a discussion of some of the key topics and issues ARB staff encountered while developing the revised GHG reporting regulation, including topics relevant to all or most of the industry sectors subject to reporting, and how we resolved them. Section III, which follows, provides more detailed information specific to each industry sector.

A. General GHG Reporting Topics and Issues

1. Selection of Sources

The Initial Statement of Reasons for the current ARB GHG reporting regulation (ARB 2007) states that:

> The staff proposal represents an initial set of reporting requirements. As required by the Act, this regulation will be periodically reviewed and updated. Reporting requirements will be refined for the sectors already included, and new sectors will be added.

ARB staff considered several factors in the selection of the additional sources for mandatory reporting. With other Western Climate Initiative (WCI) jurisdictions, California shared a design commitment to develop a broad, economy-wide market trading program, and ARB worked with other jurisdictions represented on the WCI Reporting Committee to develop Essential Requirements for Mandatory Reporting for 18 industrial sectors to support such a program (WCI ERMR 2009). WCI identified an additional 14 sectors for additional work. Meanwhile the U.S. EPA completed rulemaking on a broad-scope federal mandatory reporting rule, with 40 separate industrial sectors identified for reporting. ARB staff reviewed both the WCI Essential Requirements and the U.S. EPA rule relative to the occurrence of source types in California.

Following participation in work through WCI to harmonize its reporting requirements with the U.S. EPA regulation, staff identified 15 source sectors, including nine new sectors, that occurred in California and for which rigorous and consistent methods were available to calculate fossil fuel combustion and process emissions. In most cases those methods were identified as options or requirements in the final U.S. EPA regulation (USEPA MRR 2009-2010).

ARB has two additional source categories which are not included in the U.S. EPA regulation. Electric power entities, required to report under the current ARB regulation (ARB MRR 2007), continue to report to address specific AB 32 requirements to account for imported electricity.[6] Petroleum and natural gas systems were added following U.S. EPA's proposal to add reporting of oil and gas production, processing and storage

[6] AB 32 specifically requires an accounting of "greenhouse gas emissions from all electricity consumed in the state," including imported electricity. California Health & Safety Code §38530(b)(2).

sources to federal reporting requirements. Final action on this U.S. EPA proposal is expected this fall.

2. Selection of Reporting Thresholds

In their 2008-09 Program Design Recommendations, the WCI Partners expressed the desire to monitor what happens beneath the agreed-upon cap-and-trade threshold of 25,000 metric tons (MT) of carbon dioxide equivalent (CO_2e) (WCI Design Recommendations 2009). The Partners adopted a reporting threshold of 10,000 MT of CO_2e to enable monitoring for leakage of emissions from sources below the cap threshold, and to assess whether the cap threshold was appropriately set. The Partners wanted to be able to recommend subsequent action if the cap threshold had unanticipated economic or emissions consequences, and the lower reporting threshold would inform their review of market impacts. In addition the Partners recognized the 10,000 MT CO_2e threshold had been included in proposed federal climate change legislation (US HR2454 2009).

ARB staff considered a reporting threshold of 10,000 MT of CO_2e during rule development in 2007, which had been proposed by some stakeholders. At that time, staff decided that a threshold of 25,000 metric tons of CO_2e would, for most sources, cover a sufficient proportion of point source emissions for the initial reporting program. That threshold, along with a 2,500 MT CO_2e threshold for electricity generating and cogeneration facilities rated 1 megawatt or higher, was included in the adopted 2007 regulation.

Staff has since carefully weighed the impacts of lowering the threshold to match the WCI design recommendation. A 10,000 ton threshold is likely to affect smaller businesses in California, and there was concern about imposing the burden of reporting on about 150 facilities affected for the first time. On the other hand, it seemed important to be able to monitor the effects of the cap-and-trade threshold on both emissions leakage below the cap and on business competitiveness above it. As a result, we are proposing inclusion of the lower threshold, but also proposing a more limited and simplified reporting requirement for facilities under the cap-and-trade threshold, as discussed below.

Staff is also proposing that the threshold for electricity generating and cogeneration facilities be raised from 2,500 MT CO_2e to the same 10,000 MT CO_2e level as other facilities. The emissions that would not be reported to ARB by the 50 affected facilities is less than ¼ of 1 percent of the inventory, and these emissions can be estimated through data reported to other agencies, including the California Energy Commission and Energy Information Administration (ARB GHG Inventory for 2000-2008). A common threshold for electricity and other facilities is also more equitable.

Staff also recognized that the U.S. EPA regulation has no threshold for some types of facilities, including cement production, lime manufacturing, nitric acid production, petroleum refineries, and electricity generating units already reporting under 40 CFR Part 75. For these facility types, and for natural gas liquid fractionators and producers

of carbon dioxide, no threshold is proposed in the revised regulation, which is consistent with U.S. EPA requirements.

Abbreviated Reporting for Facilities Emitting Less Than 25,000 Metric Tons of CO_2e. In opting to propose the 10,000 metric ton CO_2e threshold consistent with other WCI jurisdictions, staff has attempted to mitigate the reporting burden through inclusion of an abbreviated reporting option. The option would apply to facilities emitting less than 25,000 MT of CO_2e, provided they do not otherwise have a cap-and-trade compliance obligation or federal GHG reporting obligation. Eligible facilities would submit a simplified report with fewer fields. They would not need to install new monitoring equipment nor have their reports verified by a third party verification body. (All reports are potentially subject to ARB audit.) They could select default emission factors by fuel type for combustion and report fuel use. The relatively few facilities that may have process emissions to report would be able to use any method permitted in the U.S. EPA regulation to calculate process emissions. Facilities generating electricity above the threshold would include basic information about their generating systems and cogeneration systems if applicable. In addition, a later June 1 deadline is proposed, to allow these facility operators additional time to complete and submit their reports.

Staff believes the abbreviated reporting option is appropriate because it minimizes the reporting burden for facilities emitting between 10,000 and 25,000 MT of CO_2e, while providing decision makers the information needed to fully monitor the effects of a cap-and-trade program. The abbreviated reporting option would not apply to suppliers as explained in Section III.

The reporting threshold for imported electricity was given careful consideration to assure fair and equitable treatment of in-state and out-of-state electricity generation resources. The cap-and-trade compliance threshold for first deliverers of electricity applies to emissions attributed to specified facilities inside and outside of California. Specified facilities with emissions less than 25,000 MT of CO_2e will receive an emission factor of zero MT CO_2e/MWh imported into California.

Reported electricity deliveries imported into California have no threshold for the following reason: Consistent with the physical operation of the Western Interconnection, electrons cannot be traced from load back along physical pathways to specific electricity generating facilities. Due to this physical reality of the shared transmission system, all imported electricity must be treated as unspecified power from resources in the western region capable of providing power on demand, or on the margin. Importers must assure chain-of-custody through ownership share or written contracts in order to claim sources of power other than unspecified power from the western region. Importers that receive electricity from asset-controlling suppliers and multi-jurisdictional retail providers recognized by ARB must also report these deliveries as specified to assure emissions are calculated based on the system power attributes of these suppliers.

3. Reporting and Verification Schedules

At the March 23, 2010 workshop staff proposed, as part of the effort to harmonize state and federal reporting requirements, that annual emissions data reports be due to ARB on the same date as reports are due to U.S. EPA, March 31. In response to the proposed March 31 date, the comment heard most often at the workshop was that this date was not workable for the electricity retail providers expected to compile and report electricity imports data. Electricity retail providers indicated that the data they rely on from other parties is generally not available to the retail provider until later in the spring. In addition, electricity retail providers do not report to U.S. EPA, so a similar reporting date need not apply to them.

Staff reviewed this issue after the workshop, consulted further with several retail providers, and agreed that a later deadline was warranted. Therefore, and consistent with the current ARB GHG reporting regulation, the regulatory proposal includes two reporting deadlines, April 1 and June 1. The April 1 deadline would apply to all facilities and suppliers who have a federal reporting obligation or a cap-and-trade compliance obligation. The June 1 deadline would apply to all remaining reporters, including electric power entities and lower-emitting facilities not subject to cap-and-trade.

In the current ARB GHG reporting regulation, verification deadlines are October 1 (for April 1 reporters) and December 1 (for June 1 reporters). In order to allow time for annual true-up in the proposed cap-and-trade program, which needs to be completed before auctions during each year of a compliance period, it is necessary to move up the verification deadlines. Staff is therefore proposing deadlines of September 1 for those whose reports are due April 1, and October 1 for those whose reports are due June 1. This will shorten the time available for verification from six months to five months for April 1 reporters, and to four months for June 1 reporters. ARB staff believes that with efficiencies gained as everyone becomes more familiar with the verification process, with fewer verifications due overall, and with less complex reports expected for electric power entities, the more limited period is workable. Reporting entities also have the option to report ahead of reporting deadlines to allow more time for verification.

4. *De Minimis* Emissions Sources

The staff proposal retains the general framework and limits for reporting emissions as *de minimis* as permitted under the current regulation (ARB MRR 2007). This is in contrast with the U.S. EPA regulation, which has no explicit *de minimis* provision. The U.S. EPA regulation often offers a greater number of options, including less rigorous options, for calculating and reporting emissions. And some emissions do not require reporting. However, given the need for rigorous and highly accurate accounting of the emissions that may be subject to a cap-and-trade program, the proposed ARB regulation is more prescriptive for most sources at affected reporting entities.

So why permit *de minimis* reporting at all, then? Staff recognized that despite the need for high accuracy reported by a facility's overall inventory, there are some very minor sources for which the methods specified in the proposed regulation would be overly prescriptive and costly. Allowing emissions from these sources to be handled with

"lower tier" methods would not risk a material misstatement for the facility because the sources are too minor. And because the proposed regulation is more prescriptive, the need for *de minimis* reporting, with appropriate limitations, becomes more acute.

The staff proposal would limit emissions claimed as *de minimis* to specific emissions chosen by the operator that represent no more than 3 percent of total facility emissions, not to exceed 20,000 metric tons of CO_2e emissions. Emissions would still be estimated and reported for the selected *de minimis* sources, but alternative emission estimation methods could be used.

There is some adjustment of the *de minimis* language in the proposal for the revised regulation, such as more direction for what verifiers should consider when assessing sources reported as *de minimis*. In particular, where such emissions have been calculated and reported to U.S. EPA under the requirements of 40 CFR Part 98, the operator would be required to report them similarly to ARB. The U.S. EPA requirements thus become a "floor" for emissions that they cover.

ARB staff recognizes that the cost of tracking emissions for every small source using the regulation's specified methods can be excessive, and that facilities may be in a position to use sound alternative methods to estimate emissions from these sources. The regulatory proposal thus allows for sources specified by the operator as *de minimis* to be calculated using alternative methods chosen by the operator, subject to the limitations above. Such *de minimis* emissions would still be reported to assure the completeness of the emissions data report, and the chosen estimation methods would remain subject to the verifier's oversight and professional judgment that they are reasonable and unbiased.

5. Enhancements to Monitoring Requirements

The staff proposal incorporates most of the general monitoring requirements of 40 CFR Part 98, Subpart A. Some additional requirements are included in the proposal to safeguard data collection for the cap-and-trade program. These are discussed below.

Measurement Device Calibration and Accuracy. The current ARB regulation requires facility operators to "employ procedures for fuel use data measurements that quantify fuel use with an accuracy within ±5 percent" (ARB MRR 2007). The regulation further requires measurement devices to be "maintained and calibrated in a manner and at a frequency required to maintain this level of accuracy." The staff proposal essentially replaces this requirement with the similar requirements at 40 CFR §98.3(i), which require measurement device calibration according to the manufacturer's recommended procedures, an appropriate industry consensus standard, or a method specified elsewhere in the federal regulation. The federal rule requires all measurement devices to be calibrated to an accuracy of ±5 percent, with initial calibrations to be conducted in most cases by April 1, 2010.

40 CFR §98.3(i) adds specific requirements by type of flow meter. Fuel billing meters are exempted from the calibration requirements, unless the fuel supplier owns both the

meter and the unit combusting the fuel. The federal requirements then make another exception that is qualified in this staff proposal.

Under 40 CFR §98.3(i)(6), an operator may postpone initial calibration of measurement devices if it would require "removing the device from service and shipping it to a remote location, causing a disruption of normal process operation. In such cases, the owner or operator may postpone the initial calibration until the next scheduled maintenance outage, and may similarly postpone the subsequent recalibrations." The postponements must be documented in the monitoring plan required by the regulation.

Concerned about the potential for indefinite postponement of calibrations that would ensure fuel use measurement accuracy, WCI initially proposed that calibrations be required during the next facility maintenance period, regardless of whether or not it was scheduled. Commenters objected because unscheduled maintenance periods are not of predictable duration to ensure enough time for calibration when the meter must be removed from service. WCI's Reporting Committee agreed and settled on alternative language.

ARB staff considered WCI's proposed language and established that it would be effective for meeting the needs of ARB programs. For facilities in the cap-and-trade program the staff proposal thus includes a requirement that when meter calibration is postponed as documented in a monitoring plan, the ARB Executive Officer is to be notified of the reasons for the postponement and the date when calibration will be completed. Such postponements would be subject to his or her approval. This is to prevent potential abuse of the U.S. EPA allowance of indefinite postponement of measurement device calibration when measurement accuracy is critical. It would apply only to postponements after January 1, 2012. Though we expect calibration postponements to be relatively rare – operators share an interest in accurate monitoring under a cap-and-trade program – this additional requirement will serve the purpose of informing ARB staff of potential measurement problems at specific facilities, and taking corrective action where important to the integrity of emissions estimation.

Weekly Monitoring of Fuel Use Data. The proposed regulation augments the U.S. EPA requirement to maintain a written GHG Monitoring Plan by requiring the plan to include regular checking of fuel measurement equipment when it is used to calculate GHG emissions. At least weekly, affected operators (those above 25,000 MT of CO_2e who do not use CEMS to report GHG emissions) would be required to monitor fuel measurement equipment and maintain records of its proper operation.

As discussed in this report, staff believes it is necessary to include separate requirements for the substitution of missing fuel analytical data in the proposed regulation. In turn it is necessary to collect data that would be needed to support the missing data substitution procedures for fuel use. This would include recording weekly fuel use data (daily data is warranted in some situations, but this would not be required). By recording regularly the amount of fuel consumed, the operator builds a base of data that can be drawn upon if it becomes necessary to substitute for missing data when

equipment breaks down. The operator benefits from this active monitoring because the weekly or daily data collected reduce or eliminate the need for more punitive data substitution in a missing data situation. The records of fuel consumption should be sufficient for the application of the missing fuel use data substitution procedure in section 95129(d)(2) of the regulation, in case the use of that procedure becomes necessary.

6. Reporting of Electricity and Heat/Steam Purchases

Staff has proposed to continue the reporting of electricity and heat or steam purchases by facilities, but not extend it to suppliers or other reporting entities. Such information would still be reported, by each provider, in kilowatt-hours (kWh) for electricity received and British thermal units (Btu) for heat, cooling or steam. This information is not required under current U.S. EPA or WCI reporting requirements, but is usually required in reports to voluntary registries. Unlike reporting to voluntary registries, energy purchases reporting to ARB does not require an emissions calculation, but information is collected that would enable such calculations by ARB.

Although there is no compliance obligation proposed for purchased energy under the proposed cap-and-trade program, the information required under the current reporting regulation is being used for benchmarking and other analyses related to cap-and-trade program development, and is expected to assist program implementation. The information has also proven important for other ARB GHG control strategies, and will be used in particular to support implementation of the energy efficiency and co-benefits audits regulation. As has been past practice, any indirect emissions calculations would be estimated in an entirely separate accounting framework to avoid any potential double-counting.

Indirect energy usage also provides a more complete picture of the emissions footprint of the facility. As facilities consider changes that would affect their emissions – addition of a cogeneration unit to boost overall efficiency even as it increases direct emissions, for example – the relative impact on total (direct plus indirect) emissions by the facility level should be monitored. Annually reported indirect energy usage also increases the conservation awareness of the facility and provides information to ARB as we consider future strategies related to industrial sectors. For these reasons, we have included the requirement to report indirect energy usage in the staff proposal.

7. Clarity of Terms for Who Reports

In the current GHG reporting regulation, the term "operator" is applied to anyone who reports, even those reporting electricity transactions. In the U.S. EPA regulation, reporting is done by facilities or suppliers, and the term "operator" applies to "the person who operates or supervises a facility or supplier." With several types of entities responsible for reporting, and different provisions of the proposed regulation applying differently to these different types of entities, it is important that these terms be applied consistently within the proposed revised regulation – and consistently with U.S. EPA's usage in their reporting regulation –to avoid confusion and because the proposed ARB regulation refers repeatedly to provisions of the federal regulation.

Thus, in the proposed revised regulation the broad term we are applying to everyone who reports is "reporting entity." The reporting entity may be either a facility operator, a supplier of fuels or carbon dioxide, or an electric power entity. Each has separate reporting obligations, but there may be some operators who also report as suppliers (e.g., petroleum refineries).

ARB staff has tried to apply these terms selectively. We use "reporting entity" when we mean anyone who reports. Some provisions apply to facility operators only, and some to facility operators and suppliers but not electric power entities, so in such cases we have tried to be specific. Also, within a reporting sector, additional terms may apply. The provisions that apply to retail providers who do not import or export electricity from California are more limited, so a distinction by type of electric power entity is made. The type of fuel supplier is specified in sections 95121 and 95122, because requirements vary among position holders, enterers, and fractionators, as examples. And the term "facility operator" may be shortened to "operator" within a section of the regulation that addresses only a particular type of facility. It is important when the reader is in doubt about an interpretation to consult the definitions in the regulation.

8. Non-Submitted/Non-Verified Emissions Data Report

For a reporting entity in the cap-and-trade program, the verified emissions data report is the basis for their compliance obligation. Language was needed to address the situation where a reporting entity may fail to submit an emissions data report by the applicable reporting deadline or fail to have an emissions data report verified by the applicable verification deadline. In all cases, it is best for the reporting entity to submit a verified emissions data report on time that accurately represents its GHG emissions and forms the basis of its obligation in the cap-and-trade program. In the absence of a verified emissions data report, the Executive Officer will now look at several factors to develop an assigned emissions level for the reporting entity. These factors include looking at the general days and hours of operation for the reporting entity and the maximum emissions associated under those conditions. The Executive Officer will also evaluate and consider any related data submitted for any other regulatory purposes. This method not only ensures a conservative calculation of the reporting entity's emissions, but hopefully encourages all reporting entities to comply with the regulation.

9. Enforcement

The goal of the proposed revised GHG reporting regulation remains the same as the goal of the current GHG reporting regulation – to collect complete and accurate GHG emissions data from those subject to reporting. The revised regulation includes the additional goal of providing stringent, accurate emissions data to support the proposed cap-and-trade program. Based on ARB's experience with the current GHG reporting regulation, and in order to address the stringency needed to support the proposed cap-and-trade program, the enforcement provisions of the current GHG reporting regulation have been revised.

Since the implementation of the current GHG reporting regulation, ARB staff has worked closely with reporting entities, third-party verification bodies, and verifiers to assist them in complying with the regulation. This has included providing guidance documents, training, workshops, on-line reporting tools, and having staff readily available to answer questions. ARB staff will continue to provide this assistance with regards to the proposed revisions described in this staff report, including the revised enforcement provisions. The enforcement provisions of the proposed revised regulation are contained in section 95107.

Violations. Section 95107 makes clear what constitutes a violation of the proposed revised GHG reporting regulation. The revised provisions clarify the number of days, or portions thereof, of violations for failing to comply with the revised regulation. For instance, if an emissions data report is not submitted, is submitted late, or contains incomplete or inaccurate information, each day or portion thereof that the report is late will constitute a separate violation of the proposed regulation. The section also clarifies what is meant by "inaccurate." In this instance, "inaccurate" means that the information is not within the level of reproducibility of a test or measurement method required by the proposed regulation. These same violations would result if a verification body fails to submit a verification statement by the required deadline in the proposed regulation (see proposed revised section 95103(f)). Each day or portion thereof that the verification statement is late would constitute a separate violation of the proposed regulation. Furthermore, given that section 95103(f) requires the reporting entity to obtain the services of a verification body and that such services must be completed by the regulatory deadline, a late submitted verification statement could also lead to a violation by the reporting entity.

In addition, this section also clarifies that each failure to comply with the methods in the proposed regulation for measuring, collecting, recording, and preserving information needed for the calculation of emissions constitutes a separate violation of the proposed regulation. This violation has been included in the proposed revisions because it ensures that reporting entities will utilize the methods required by the regulation, which further ensures the stringency of calculations and resulting reported emissions data. This provision is also consistent with 40 CFR §98.8 of the U.S. EPA Mandatory Reporting Rule (U.S. EPA MRR 2009).

Moreover, in order to maintain consistency with the proposed cap-and-trade program and other AB 32-related regulations, the proposed revisions clarify that the failure to accurately report GHG emissions data will result in a separate violation for each metric ton of CO_2e emitted but not reported as required by the proposed regulation. As mentioned above, the proposed revisions are necessary to ensure accurate and stringent emissions data in order to support a cap-and-trade program, and this violation is designed to ensure that reporting entities accurately report their GHG emissions to ARB and that the number of violations directly reflects the amount of CO_2e emissions. A metric ton was selected as the essential unit of violation for unreported emissions because metric tons are the basic unit both for reporting emissions and for allocations under the proposed cap-and-trade regulation. By using metric tons, the number of

violations will remain proportional to emissions, which is in keeping with the statute's overall intent to reduce emissions. In addition, existing enforcement statutes direct ARB to consider, when determining administrative penalties, the "extent of harm caused by the violation," and the "nature and persistence of the violation." (Health & Safety Code (H&SC) §§ 42410(f) and 42403.5(b)(1)(2)). Proposed regulation section 95107(c) makes specific that the "extent of harm" and the "nature" of a failure to report will be analyzed, for penalty purposes, in terms of metric tons. A similar violation is included in the proposed cap-and-trade regulation, as well as the proposed Renewable Electricity Standard regulation (*see* proposed Title 17, *California Code of Regulations* (CCR), section 97009).

Finally, the current regulation included the "knowing submission of false information, with intent to deceive" as a separate violation. As noted by the WCI in its *Response to Stakeholder Comments and Final Draft Essential Requirements for Mandatory Reporting* (WCI Response to Comments 2009), strict liability is the normal standard for the imposition of civil liability in environmental regulatory programs. In fact, AB 32's enforcement provisions expressly incorporate existing strict liability enforcement statutes such as H&SC sections 42400 and 42402 without any statutory language indicating an intent to require a higher, narrower standard of 'knowing' or 'intent to deceive' in every instance. Other ARB environmental regulations, including the Low Carbon Fuel Standard (Title 17, CCR, section 95484(e)) and the Airborne Toxic Control Measure for Auxiliary Diesel Engines Operated on Ocean-Going Vessels At-Berth in a California Port (Title 17, CCR, section 93118.3(h)), use the normal strict liability standard, rather than the knowing, with intent to deceive standard. Stakeholders have raised the same concerns addressed in the WCI Response to Comments 2009 with ARB. In order to ensure consistent enforcement with other ARB environmental regulations, and in accordance with the WCI, the proposed revised regulation has replaced the "knowing submission of false information, with intent to deceive" standard of liability with a strict liability standard.

Penalties. The proposed revised enforcement provisions implement and make specific H&SC section 38580(b)(3), which authorizes ARB to develop a method to convert regulatory violations into the number of days of violation for the purposes of the penalty provisions specified in section 42400 et seq. of the H&SC. Moreover, consistent with H&SC section 38580, the proposed revised regulation provides that the following remedies are available for a violation of any GHG reporting regulation provision:

(1) Civil and criminal penalties under H&SC § 42400 et seq.; and
(2) Injunctive relief under H&SC § 41513.

In addition, the proposed revisions clarify that the Executive Officer may revoke or modify any Executive Order issued under the proposed regulation as an additional sanction for violating the requirements of the proposed regulation.

It is important to emphasize that ARB's goal is to collect accurate GHG emissions data to support ARB's GHG inventory and proposed cap-and-trade program, not to collect

penalties. As we have for the current GHG reporting regulation, we will continue to work closely with those subject to reporting and our third-party verifiers to assure that we can meet this goal.

ARB Enforcement Actions. Enforcement and compliance assurance of the proposed revised GHG reporting regulation could involve some or all of the following ARB staff activities:

- Receipt of annual GHG emissions data reports from reporting entities;
- Accreditation process for verification bodies and verifiers;
- Conflict of interest assessments of verification bodies;
- Receipt of verification statements from verification bodies for each reporting entity's GHG emissions data report, when applicable;
- Review of the reports and verification statements for completeness and accuracy;
- Evaluation of emissions data in the emissions data reports to determine if the reporting entity is in compliance with the requirements of the GHG reporting regulation;
- Inspections or audits of the reporting entities and verification bodies to verify and validate the information submitted in the reports and verification statements, and to verify and validate that reporting entities are utilizing the methods required by the GHG reporting regulation;
- Preparation and issuance of notifications of violation;
- Meeting with violators for the purpose of mutual settlement;
- Participation in litigation, if necessary.

The enforcement process would begin when a possible violation of a requirement of the regulation is detected by or brought to the attention of ARB. A violation may be brought to the attention of ARB by a wide variety of sources, including through self-reporting. Self-reported violations are generally considered more favorably in the enforcement process. Once ARB has been made aware of a violation, ARB gathers all available information and makes a final determination as to whether a violation has in fact occurred. If ARB determines that a violation has occurred, ARB will notify the party involved. Such notification would set forth the basis for ARB's determination, the regulatory requirements violated, and any proposed penalty.

ARB anticipates that most violations will be resolved promptly. In unusual cases, ARB or the party involved may wish to schedule an office conference, providing the party with the opportunity to present any mitigating information the party believes is relevant to the matter. Based on the information provided, ARB will review its findings and, if it still determines that a violation has occurred, ARB will propose a resolution. A resolution may be comprised of a financial penalty, determined based on the factors as set out in H&SC § 42403. These factors include: frequency of past violations, the duration of the violation, the nature and persistence of the violation, the financial benefit gained by the violator, actions taken to ameliorate the violation, and the financial burden to the

violator. ARB may also propose certain action measures designed to minimize the potential for further violations.

ARB's overall enforcement goal is to assure compliance with all regulatory requirements, and its enforcement efforts, in any enforcement situation, begin with bringing the party back into compliance. Once compliance has been achieved, ARB's enforcement efforts are focused on deterring future noncompliance.

B. GHG Data Reporting Submittals and Recordkeeping

1. GHG Reporting Mechanism

As staff indicated at the March 23, 2010 workshop, we are working closely with U.S. EPA in an attempt to develop a unified reporting system for state and federal GHG reporting. U.S. EPA has indicated a strong desire to assist states in meeting the needs of their GHG reporting and control programs, and we hope to have this system in place by 2012, in time for the initial year of reporting under the revised regulation.

Under both the current regulation and this staff proposal, reporting entities must submit reports to ARB using the ARB GHG Reporting Tool "or any other reporting tool approved by the Executive Officer that will guarantee transmittal and receipt of the data required." ARB staff is working with U.S. EPA to attempt to enable their reporting framework, supplemented if needed with a mechanism for additional data submittal to California, to serve that purpose.

2. Release of Reported Emissions Data

The main objective of the mandatory GHG reporting program is to provide complete, detailed, and accurate facility-specific GHG emissions data. ARB staff's intention is to provide quality emissions data to the public as quickly as practical, but with recognition that verification is an important step in the process. We expect to provide annual facility-level emissions reports and various summary reports based on the submitted data. In most cases, these reports would include only verified data, but release of unverified data may be necessary in order to provide complete summary information for a calendar year. Unverified data would be flagged as unverified. GHG emissions data reported under the revised regulation would be available through ARB websites beginning in 2012.

3. Designation of Confidential Information

Stakeholders subject to reporting have sometimes expressed concern for the protection of commercially sensitive data, while community organizations have urged a high level of transparency for the data used to calculate emissions. ARB must balance these competing needs. As indicated in the proposed regulation, ARB will continue to handle sensitive information and claims of confidentiality by following the procedures specified in ARB's confidentiality regulations, which are contained in title 17, California Code of Regulations, sections 91000 to 91022. These regulations allow companies who submit information to ARB to claim such information as confidential. The regulations also

specify a process for ARB's handling of such information. ARB staff has many years of experience handling confidential information and takes its responsibilities very seriously. All information that is designated as confidential will be handled in strict accordance with ARB confidentiality regulations.

The proposed regulation requires reporting entities to report both emissions data and non-emissions data. There are some limits on what can be claimed as confidential by the reporting entity. The California Public Records Act (Government Code section 6250 et seq.) provides that all air pollution emissions data are public records (see Government Code section 6254.7(e)). Accordingly, the proposed regulation specifies that emissions data, including estimates of facility emissions, are public information and cannot be claimed as confidential. For non-emissions data that have been claimed as confidential by the operator, members of the public can use the procedures specified in ARB confidentiality regulations (cited above) to request access. ARB staff would then notify the affected facilities or entities to provide justification for the claims of confidentiality, consistent with the procedures specified in the regulations.

Reporters to U.S. EPA should be aware that the agency has proposed special rules to address the confidentiality of data submitted under their regulation. The July 7 proposal can be found at http://edocket.access.gpo.gov/2010/pdf/2010-16317.pdf. Given that certain information reported to U.S. EPA will be designated by U.S. EPA as non-confidential (e.g., public), ARB staff proposes to consider this same information as public for purposes of the proposed revised regulation.

C. Missing Data Substitution Procedures

In assessing the suitability of the U.S. EPA reporting rule for cap-and-trade, it became readily apparent that many of the provisions for substitution of missing data could be easily subject to abuse. Aware that the incidence of missing data substitution is low in the Acid Rain Program, due to its stringency in support of market trading, ARB staff looked to Part 75 as a model (USEPA Part 75)for missing data provisions in the proposed revised regulation.

Accurate emissions accounting is essential for the state's emission inventory, for informing other climate programs, and for a market-based program to reduce GHG emissions. The emissions collected under the GHG reporting rule form the basis for trading in a carbon market. The fuel monitoring and sampling requirements as well as emission calculation methods in the proposed rule enable sound emissions accounting. However, because emissions are either measured directly by CEMS or calculated from measured fuel/feedstock data, and in practice measurement equipment and fuel sampling system may occasionally malfunction, additional requirements to address missing data are necessary to ensure the parameters used to estimate emissions are fully accounted. If some of these required data are missing, emissions can be underestimated, resulting in the reporting entity being responsible for a smaller compliance obligation and creating a perverse incentive to miss more data. This can open up opportunities for gaming the cap-and-trade system. For these reasons, a

regulatory prescription for how to substitute for missing data is imperative for ensuring the integrity of the carbon market.

1. Review of U.S. EPA Approach

In its GHG reporting rule, U.S. EPA attempts to address missing data substitution for stationary fuel combustion in Subpart C and in each industry-specific subpart for process emissions. In 40 CFR §98.35, the U.S. EPA requires operators to substitute missing fuel characteristic data (e.g. high heat value, carbon content, and moisture content) using the average of measured values immediately before and after the missing data period, and substitute missing fuel consumption and flow rate data using the best available estimate, while requiring Part 75 (Acid Rain Program) sources to follow the existing missing data substitution procedures in Part 75 . ARB staff finds that the Part 75 approach (USEPA Part 75) is sufficiently stringent to support cap-and-trade. Part 75 takes a tiered, increasingly more punitive approach in data substitution, such that the more data are missed, the increasingly more conservative (higher) value must be used for substitution. It produces higher emissions numbers and an incentive for operators to achieve a high data capture rate, especially when a carbon price is in place.

However, for non-Part 75 sources, ARB staff finds that U.S. EPA's approach in Part 98 leaves data substitution methods largely to the operator's discretion and is not sufficient for supporting a cap-and-trade program. First, the U.S. EPA approach gives operators much latitude in choosing a data estimation method, which can make it difficult for verifiers to validate the credibility of the operator's chosen method and can generate significant need later for ARB staff to review and interpret each estimation case. Second, substitution using "before" and "after" values can potentially leave out periods of peak production and underestimate emissions, if the "before" and "after" values are lower and not representative of the missing production period. Third, the U.S. EPA's data substitution approach does not put a limit on the amount of data that could be missing from a year, which can potentially undermine the data quality. Last, the difference in stringency of the data substitution requirements for Part 75 units and non-Part 75 units presents an inequality issue for regulated entities. For these reasons, staff believes that more prescriptive data substitution procedures must be included in the revised GHG reporting rule to ensure data quality and equity in emission accounting for cap-and-trade.

2. Proposal for Missing Data Substitution

In writing prescriptions for missing data substitution, staff looked to 40 CFR Part 75 (revised as of July 1, 2009) (USEPA Part 75) as a model because 40 CFR Part 75 is an existing market-based program that has had success achieving its objectives. Staff identified the data parameters that need more stringent missing data substitution procedures beyond what is in the U.S. EPA's Part 98 GHG reporting rule and applied a similar tiered, increasingly punitive concept of Part 75 in writing the new substitution procedures.

Unit Reporting Emissions Using CEMS. For Part 75 units, which are reporting their CO_2 emissions using CEMS operated in accordance to Part 75 rules, staff's proposal is consistent with the U.S. EPA requirements. For other non-Part-75 units that report CO_2 emissions using CEMS, staff proposes to require the operators to substitute missing data according to Part 75 requirements. This will level the playing field among all sources that report emissions using CEMS.

Fuel Characteristic Data. Fuel characteristic data, such as high heat value and carbon content, generally have a range of values that is not arbitrary by definition, and the variations in values tend to be reasonably bounded. Therefore, staff determines that if a facility is missing a small amount of data (<10%), substituting with the average of the "before" and "after" values consistent with the U.S. EPA rule provides a reasonable estimate. Staff further creates 2 additional tiers of data substitution. If triggered due to percent data capture rate falling below 90% and 80%, the operator is required to substitute the missing value with the highest value recorded in 3 years or in all records kept, respectively. To ensure that the substituted value is at least as conservative as the default heat contents of 40 CFR Part 98 and the default carbon contents of Part 75, staff proposed to require the operator to use the greater of the default value or the highest value in facility records for substitution.

Fuel Consumption Data. For substitution of missing fuel consumption data, as long as the annual total facility level fuel consumption can be accurately determined, so that the annual total emissions can be accurately calculated and compliance obligation appropriately assessed yearly, the operator has leeway in estimating missing fuel consumption data at the sub-facility level using the best available estimate method. Because facilities typically have fuel metering at different levels (for example, a revenue meter at the facility level and other meters at the unit level), operators must be able to match up the fuel use records at the different levels at the end of the year, which result in the best available estimates to true up to the annual facility fuel use quantity. In this case, there is no concern with operators potentially gaming the system because the true up of fuel records must be verified by a third-party verifier. However, in the unlikely scenario that the facility level fuel consumption cannot be accurately determined, and the unit fuel consumption is also missing, staff prescribes stringent missing data substitution procedures to be applied at the unit level.

Unlike fuel characteristic data which generally has a range of values by definition, fuel consumption can range anywhere from zero to the maximum potential capacity of the equipment; therefore, staff believes that missing fuel consumption data must be filled with values that can either be correlated with other measured operational parameters or be based on the actual fuel use values under usual operating conditions. Staff prescribes data substitution procedures for load-based units (units producing electrical and/or thermal output that are equipped with data handling system that can automatically match up output data with fuel use data) and non-load-based units. After reviewing Part 75 procedures for load-based units (USEPA Part 75), and finding that these procedures are likely to produce reasonably accurate estimates, staff decided to model the proposed procedure after the Part 75 rule, with modifications to suit

California's applications. For non-load-based units, staff applied a similar tiered concept as Part 75 and created 4 tiers of data substitution, requiring the operator to use a best available estimate consistent with the U.S. EPA Part 98 if data capture rate is greater than 95%, and use the 90th or 95th percentile value of fuel use rates in the facility's records if data capture rate is below 95% or 90% (but greater than 80%), respectively. In section 95103, the revised rule requires the facility operator to periodically monitor the proper functioning of fuel measurement device and record fuel use data at least weekly. Such monitoring will form the basis for missing data substitution (see the section on *Enhancements to Monitoring Requirements* in this chapter for a discussion of this requirement). If a unit does not meet the criteria for using either the load-based or the non-load-based procedure, the operator must conservatively substitute missing data using the maximum potential fuel flow rate. However, given that the proposed rule provides the option for facilities to use a best available estimate if facility level fuel consumption can be accurately determined, staff expects that it will be rare for any facility to use the maximum potential fuel flow rate as the last resort.

Alternative Monitoring Plan. In addition, in the interest of balancing the collection of accurate data and creating an incentive to achieve a high data capture rate using a conservative substitution approach, the proposed rule includes provisions to allow operators to submit an alternative interim monitoring plan for ARB's approval in the event of unforeseeable breakdown of equipment that is expected to cause a missing data rate of more than 20%, which is the threshold for an automatic nonconformance. The proposed rule provides guidelines for alternative monitoring plans and also makes allowance for sources reporting using CEMS (Tier 4) to temporarily use a fuel-based calculation method (Tier 2 or Tier 3) if certain criteria are met.

Cumulative Missing Data Elements. To address the situation of having multiple parameters each with less than 20% of missing data, but in combination causing more than 20% of emissions to not be directly accounted for, staff defines the minimum amount of data that must be captured in order to avoid a nonconformance finding as cumulatively 80%. In other words, missing data elements cannot cumulatively cause more than 80% of emissions to not be directly calculated from measure parameters. Otherwise, it is an automatic nonconformance even if the operator has correctly followed all the missing data substitution procedures in the rule. However, a nonconformance does not necessarily prevent a positive verification finding, depending on the contribution of the source to the facility emissions total.

D. Accounting for Biofuel Purchases Used in Stationary Combustion

1. Background

After it was determined that biomass-derived fuels would not be required to have a compliance obligation for their CO_2 emission under the Cap-and-Trade Regulation, it became clear that simple reporting of biogenic emissions would not be rigorous enough for avoiding a compliance obligation. In regards to this issue, staff assessed the following concerns: 1) the motivation to over-report biomass-derived fuels would be high because of the avoided compliance obligation; 2) some biomass-derived fuels, mainly

manure digester gas, had the potential for receiving double credit for emissions reductions; once as an offset, and then again as a biomass-derived fuel without a compliance obligation; and 3) there was a need to prevent the simple redirection of biomass-derived fuels from other states to California because of the increased economic incentive, considered in effect to be contract shuffling without real reductions in emissions overall. To address these concerns, staff determined that a system needed to be put in place to protect the integrity of the cap-and-trade program.

2. Basis for Proposal

For the proposed revised regulation, staff held discussions with stakeholders to determine the relevant issues and reviewed a variety of alternatives. As a result of these discussions, staff determined that any system designed to ensure the validity of reported CO_2 emissions from biomass-derived fuels needs to meet several criteria: (1) it needs to protect the integrity of the cap-and-trade program; (2) it needs to be implementable in a short time period; (3) it needs to cover all fuels, even those produced out of state; and (4) it needs to be cost effective. Two main ideas were developed in an attempt to satisfy these criteria. The first was to expand verification to include biomass-derived fuels. The second was to try to create a biomass-derived fuel certification program. Although a certification program similar to the Renewable Energy Certificate under the Renewable Electricity Standard regulation (Title 17, CCR, section 97000 et seq.), with an elevated level of assurance, would be an ideal solution, time constraints prevented the development of this program at this time. An achievable alternative, therefore, was to expand the existing verification program to include specific requirements for verification of biomass-derived fuels. Staff encourages stakeholders to provide comments on the possibility of developing a certification program in the future.

3. Reporting and Verification Requirements and Methods

Expansion of the verification systems to included biomass-based fuels will necessitate minor changes to the reporting process to separate biomass-derived fuels that have a compliance obligation under the Cap-and-Trade Regulation from those that do not. Reporting entities will be required to self-report whether the biomass-derived fuel they are reporting has a compliance obligation or not. During the normal verification process the verification team will also evaluate the accuracy of biomass-derived fuel reporting. There are several criteria the verification team will examine, including:

1. Is the fuel listed as a biofuel without a compliance obligation and does it meet all the requirements in 95851.2 of the Cap-and-Trade Regulation?
2. Was the contract in place before January 1, 2010 or is the fuel coming from increased production in order to avoid contract shuffling?
3. Was the fuel used in any other greenhouse gas reduction system?
4. Can the fuel be tracked from production to reporting entity?

The last question is most critical in the case of biomethane where the fuel may be produced in another state, injected into a common transmission pipeline where it is mixed with natural gas, and never actually delivered to the end-user. The fuel ownership may pass through many hands before it arrives at its final destination. This

will necessitate verification at multiple locations. The producer must be verified to determine that the fuel meets all criteria in the regulations and that total production meets or exceeds total sales of biomass-derived fuel. All marketers or middle parties in the chain of custody must also be verified to make sure that their biofuel sales do not exceed their purchases. The responsibility for verification of the biomass-derived fuel falls on the entity avoiding the compliance obligation as listed in section 95852.1 of the Cap-and-Trade Regulation.

There are two drawbacks of this solution. First, it will entail a more extensive verification than a certification program would need in order to maintain the integrity of the cap-and-trade program. Second, this program will not allow uncapped stationary sources that purchase their own biomass-derived fuel to receive credit for that fuel. In the case of natural gas, it is assumed the local distribution company (LDC) will adjust the cost of natural gas to include the cost of complying with the cap-and-trade regulation. Capped entities will not bear this cost because they are responsible for their own natural gas emissions. Uncapped entities, which are not directly responsible for their natural gas emissions, will pay this cost because there is no way to back out the biofuel purchase from the LDC's compliance obligation.

III. SECTOR SPECIFIC REPORTING REQUIREMENTS

This section provides chapters that describe the reporting requirements specific to each sector subject to the GHG reporting regulations and how they were developed.

A. Stationary Fuel Combustion Sources

1. Background

Most industrial facilities emitting GHGs have stationary fuel combustion sources. Section 95115 of the proposed regulation specifies the methods for estimating emissions from these sources for all industrial sectors. Stationary fuel combustion includes devices that combust solid, liquid, or gaseous fuels, generally for the purposes of generating steam, producing electricity, providing useful heat or energy for industrial, commercial, or institutional use, or reducing the volume of waste by removing combustible matter. Stationary fuel combustion sources include, but are not limited to, boilers, simple and combined-cycle combustion turbines, engines, incinerators, and process heaters.

In early 2010 staff had discussions with U.S. EPA staff on the federal reporting requirements for stationary fuel combustion sources, which had not been developed to support cap-and-trade. As discussed in Section I, ARB staff also participated in extensive discussions with the other Western Climate Initiative (WCI) jurisdictions through the WCI Reporting Committee, to identify changes or limitations to U.S. EPA MRR requirements that would result in compliance grade emissions calculations for cap-and-trade while minimizing any need to report different numbers than those reported to U.S. EPA. In March 2010, ARB staff presented current thinking on proposed requirements for stationary combustion at a public workshop, and received comments at the workshop and thereafter. Stakeholder comments on the WCI harmonization proposal (WCI HER 2010) were also reviewed by ARB and discussed with stakeholders and other state representatives on the WCI Reporting Committee. Taking into consideration this variety of input, staff prepared the final regulatory proposal.

2. Basis for Proposal

For the proposed revised regulation, ARB staff relied on the foundation provided in the U.S. EPA mandatory reporting regulation. Subpart C of the U.S. EPA regulation specifies GHG emissions monitoring and reporting requirements for general stationary fuel combustion emissions sources, including methods for calculating CO_2, CH_4, and N_2O emissions from these sources. U.S. EPA's methods involve a series of tiers, with rigor increasing from Tier 1 through Tier 4. ARB and WCI worked within this structure to develop appropriate limitations to U.S. EPA's specifications by fuel type, focusing on the need to ensure accurate carbon values when fuels are likely to have high carbon variability. This approach to harmonization works because the U.S. EPA rule always allows sources to be estimated using a higher tier. GHG emissions reports that meet

the proposed ARB requirements would in most cases also meet the U.S. EPA reporting requirements, avoiding the need to prepare and submit two different reports.

In developing the currently proposed ARB regulation, staff reviewed the U.S. EPA *Technical Support Document for Stationary Fuel Combustion Emissions: Proposed Rule for Mandatory Reporting of Greenhouse Gases* (USEPA TSD C) and the *Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments Volume No.: 15. Subpart C – General Stationary Fuel Combustion Sources* (USEPA Comments C 2009). We evaluated the adopted federal GHG reporting requirements and methodologies (USEPA MRR 2009-2010) for stationary fuel combustion sources and compared them to the current ARB GHG reporting requirements (ARB MRR 2007). As discussed above, staff also discussed with state and provincial colleagues in the WCI Reporting Committee which U.S. EPA requirement adequately supported data needs for a cap-and-trade program, and where limitations or changes were needed. Stakeholder input via WCI and directly to ARB staff is also reflected in the staff proposal

3. Reporting Requirements and Methods

The proposed ARB reporting requirements for stationary fuel combustion sources use U.S. EPA greenhouse gas emissions reporting requirements, with several limitations or modifications to ensure adequate rigor for a market trading program. The proposal addresses reporting of CO_2, biogenic CO_2, CH_4, and N_2O emissions from combustion sources. Although some modifications were needed to the U.S. EPA baseline requirements, many California facilities are already meeting the modified requirements as part of their current ARB reporting.

Emissions Calculation Methods. The U.S. EPA requirements for estimating stationary fuel combustion emissions are divided into various methods, or Tiers. Tier 1 allows use of default emission factor and fuels data. Tier 2 requires use of high heating value for the fuel, and Tier 3 requires fuel sampling to characterize carbon content. Tier 4 requires the use of continuous emissions monitoring systems (CEMS).

In general, when estimating GHG emissions from the combustion of common standardized fuels, which have limited variability in carbon content, lower-tier methods may be applied, which use either default factors, or require relatively limited fuel testing, depending on the fuel type. This helps to limit the costs and complexity of reporting, while providing good accuracy. For fuels likely to be variable in carbon content, the lower-tier methods would often result in significant underestimation or overestimation of GHG emissions; thus, higher tier methods should be applied.

Coal provides an example. The U.S. EPA regulations allows use of a Tier 2 steam production method to estimate CO_2 emissions in units that produce steam, and the use of default emission factors in units with a maximum rated heat input capacity of 250 mmBtu/hr or less. Staff at ARB and in other WCI jurisdictions believe these provisions would allow significant underestimation or overestimation of CO_2 emissions from coal. The proposed regulation would thus require carbon testing or use of CEMS (Tiers 3 or

4, respectively) when coal is used as a fuel. This requirement would apply to other solid fossil fuels, as well.

Natural gas provides a different example. U.S. EPA proposed in amendments to the regulation published August 11, 2010 to define natural gas very broadly; it could include associated gas at oil production sources and other naturally occurring field gases regardless of carbon content. The ARB staff proposal would retain use of the Tier 2 heating value method for natural gas as provided in the U.S. EPA regulation, but would limit its use to pipeline quality gas as defined in the regulation (970-1100 Btu/scf). Natural gas outside this range would be tested for carbon content if a CEMS is not used to estimate emissions.

As in the current ARB GHG reporting regulation, heating values and carbon content would be provided by the fuel supplier or tested directly by the facility consuming the fuel. When fuel sampling is required, the sampling frequencies specified in the U.S. EPA regulation are retained as sufficient for most stationary combustion sources.

For standardized (mostly liquid) fuels listed in the proposed regulation (a subset of fuels listed in Table C-1 of the U.S. EPA regulation), use of default emission factors is permitted when combusted in units with a maximum rated heat input capacity of 250 mmBtu/hr or less, except where fuel heating value analysis is routinely performed, as stated in the U.S. EPA rule. For *de minimis* sources, the option is provided to use lower-tier methods so reporters are not unnecessarily burdened with collecting analytical data for insignificant emission sources. The *de minimis* method could not be a lower tier than that required by U.S. EPA, however, if reporting of the source to U.S. EPA is required.

The staff proposal includes several other specific limitations to the U.S. EPA requirements, also consistent with the WCI harmonization document:

CEMS CO_2 Monitors. ARB staff and other WCI jurisdictions share a concern that emission factors used to convert oxygen to CO_2 concentrations are questionable for fuels with variable carbon content. As such, the staff proposal includes a requirement to install CO_2 monitors when a new CEMS with a flow monitor is installed. Staff believes that CO_2 monitors are likely to provide improved, reliable emissions data. The proposed revised regulation would not require O_2 CEMS to be retrofitted with CO_2 monitors, but would require that CO_2 monitoring be included annually when Relative Accuracy Test Audits are performed on CEMS systems annually. This additional test at minor incremental cost would help to build a base of data for comparing direct CO_2 monitoring with O_2 to CO_2 conversion.

Source Testing for N_2O and CH_4. An addition was made to the U.S. EPA requirements to allow reporters to measure site-specific facility emissions data for nitrous oxide (N_2O) and methane (CH_4) emissions, and to use the data to estimate emissions for the sources that are tested. Source test data would be used instead of default emission factors for estimating emissions. Emission measurements must be performed in

conformance with a facility source test plan submitted to and approved by ARB. This option is consistent with the current ARB requirements and is also consistent with the WCI harmonization document (WCI HER 2010). The option to use source testing is voluntary; therefore, reporters who prefer to use the other less costly methods within the regulation may do so. Several stakeholders want to retain the option even if it results in different values for federal and state reporting.

Biomass CO_2 Determination. A minor change was made to U.S. EPA requirements that require testing of municipal solid waste to determine the biomass portion of CO_2 emissions, extending the requirement to any other fuel for which the biomass fraction is unknown. Staff believes this is important for the accurate, separate calculations of fossil and biomass emissions.

Refinery Fuel Gas Sampling. The U.S. EPA regulation requires the daily sampling of refinery fuel gas when equipment is in place for daily sampling. Daily sampling has been the practice for most refineries under the current ARB GHG reporting regulation, and the staff proposal would extend it to all refineries. Staff believes this is necessary to accurately quantify emissions from refinery fuel gas, which is a highly variable fuel.

Electricity Generating and Cogeneration Units. In order to meet the requirements of AB 32 and ensure consistency with the WCI, a requirement was added to the proposed revisions to require reporting generating capacity, power generated, thermal output, and other information for electricity generation and cogeneration units.

Natural Gas Providers. Facilities using natural gas would be required to report their provider and customer account number. This will be important later for establishing the compliance obligation for fuel suppliers, if the cap-and-trade program is extended to them as proposed.

Procedures for Missing Data. For general stationary fuel combustion sources, and all emissions calculations, requirements have been added to the proposed regulation that describe how to estimate emissions if required data are missing. These requirements were discussed previously.

Benchmarking Data. For some specific products produced by facilities reporting only under stationary combustion requirements, we propose to collect specified product output data to support benchmarking activities.

B. Cement Production

1. Background

Cement production generated about 5.3 million metric tons of process-related CO_2e emissions in 2008 (ARB CA GHG Inventory for 2000-2008). A slightly smaller amount of GHG emissions were also emitted into the atmosphere that year from fuel combustion to heat the kilns where limestone is calcined to manufacture clinker. Cement plants are among one of the largest consumers of coal in California,

combusting over 990,000 short tons of coal in 2008 (ARB GHG Cement 2010). Staff has proposed the continued inclusion of cement manufacturing plants in mandatory reporting due to their contribution to the statewide GHG inventory (approximately 1.8 percent of the total in 2008) (ARB CA GHG Inventory for 2000-2008), their importance as a contributor to emissions worldwide, and their inclusion in the United States Environmental Protection Agency's Mandatory Reporting of Greenhouse Gases regulation (USEPA MRR 2009-2010).

As discussed in Section I, ARB staff also participated in extensive discussions with the other Western Climate Initiative (WCI) jurisdictions through the WCI Reporting Committee, to identify changes or limitations to U.S. EPA MRR requirements that would result in compliance grade emissions calculations for cap-and-trade while minimizing any need to report different numbers than those reported to U.S. EPA. In March 2010, ARB staff presented current thinking on proposed requirements for cement production at a public workshop, and received comments at the workshop and thereafter. Stakeholder comments on the WCI harmonization proposal (WCI HER 2010) were also reviewed by ARB and discussed with stakeholders and other state representatives on the WCI Reporting Committee. Taking into consideration this variety of input, staff prepared the final regulatory proposal.

2. Basis for Proposal

The staff proposal incorporates the U.S. EPA final reporting rule as the foundation for reporting requirements for the cement industry. Finalized in 2009 after an extensive public process, the U.S. EPA rule contains calculation methodologies that are often very similar (but not identical) to those adopted earlier by ARB after our own public process in 2007. By aligning with the wording of the U.S. EPA regulation as we develop requirements suitable for cap-and-trade, we are able to reduce duplication of effort, questions of interpretation, costs, and complexity for reporters. In most cases GHG reports that meet the proposed ARB requirements would also meet U.S. EPA reporting requirements.

In developing the currently proposed ARB regulation, staff reviewed U.S. EPA's *Technical Support Document for Process Emissions from Cement* (U.S. EPA TSD H 2009) and the *Response to Public Comments, Subpart H-Cement Production (*U.S. EPA Comments H 2009). We evaluated the adopted federal GHG reporting requirements and methodologies (USEPA MRR 2009-2010) for cement production and compared them to the current ARB MRR requirements (ARB MRR 2007).

In addition, staff discussed with state and provincial colleagues in the WCI Reporting Committee whether each harmonized requirement adequately supported data needs for a cap-and-trade program. The federal reporting program includes methodologies to quantify GHG emissions from the cement production process. Staff determined that the U.S. EPA MRR and the current ARB MRR (ARB MRR 2007) utilized equivalent methodologies with some minor differences. Staff attempted to harmonize ARB MRR requirements with the U.S. EPA MRR when the federal requirement met the need for compliance grade emissions estimation under a cap-and-trade program. Differences for

process emissions, and the rationale for including or not including them in the proposed ARB MRR, are discussed below. Differences for stationary combustion are discussed in that section of this document.

The federal regulation prescribes certain criteria that, when met, require a cement plant to determine and report GHG emissions according to the Tier 4 methodology (Continuous Emissions Monitoring System or CEMS), rather than allowing the option of utilizing a clinker-based methodology, as permissible under the current ARB MRR. We expect most of California's cement plants to calculate their GHG emissions using the Tier 4 CEMS method.

The U.S. EPA MRR also prescribes a clinker-based methodology, similar to the current ARB MRR's clinker-based methodology, to separately calculate process-related emissions when the CEMS methodology is not required. Staff evaluated the federal requirements and determined they were equivalent and in some cases more rigorous than the current ARB MRR. Staff proposes to follow the U.S. EPA MRR sampling and testing requirements to achieve consistency with the federal program while providing the degree of accuracy required for a cap-and-trade program.

The current ARB MRR requires the cement kiln dust (CKD) emission factor to be calculated when CKD is not recycled to the kiln, using the CKD calcination rate. However, staff concluded that the U.S. EPA MRR method, which utilizes total measured CaO and MgO content to determine the CKD emission factor, is equivalent to the current ARB MRR method, and we propose to follow the federal method.

Also included in the staff proposal are the calculation methods from the U.S. EPA MRR for the determination of total organic carbon (TOC) content in raw materials. Emissions arising from the organic carbon content of raw materials are negligible, and if a cement plant does not utilize the prescribed analytical methodology, the operator may continue to use the prescribed default TOC content value.

In 2008, cement plants reported total fugitive emissions equal to 0.13 percent of their total CO_2e emitted that year (ARB GHG Cement 2010) The U.S. EPA MRR does not require the reporting of fugitive emissions and the proposed cap-and-trade program excludes fugitive emissions from a compliance obligation. As such, staff proposes to follow the federal approach and to not continue to require the reporting of fugitive emissions because of their negligible contribution to overall GHG emissions and their exclusion from the cap-and-trade program.

The current ARB MRR requires cement plants to report two cement efficiency metrics. Although we do not propose to continue the reporting of efficiency metrics, we do propose to continue to collect data currently reported (total CO_2 emissions and the quantity of clicker produced) that will enable the calculation of metrics by ARB. Staff also proposes to require operators to report the annual quantity of clinker substitutes and cement substitutes consumed. This will aid with the calculation of additional efficiency metrics, assisting in benchmarking for the cap-and-trade program.

3. Reporting Requirements and Methods

As described, the proposed regulation for cement production would substantially mirror the U.S. EPA MRR requirements. Under the staff proposal, all California cement plants would be required to report combined process-related and combustion CO_2 emissions from clinker production using the Tier 4 (CEMS) methodology, or separately report combustion emissions and process-related CO_2 emissions from clinker production using the clinker-based method. They would also report process-related emissions from the organic carbon entrained in non-carbonate raw materials. Cement plants would also be required to report annual CO_2, biomass-derived CO_2, N_2O, and CH_4 emissions from fuel combustion, fuel consumption, annual quantity of raw material consumed, and other specified data. Finally, we proposed that cement plants also report supporting data to allow ARB to calculate efficiency metrics.

If the conditions specified in 40 CFR §98.33(b)(4)(ii) or (b)(4)(iii) are met, then the operator must determine CO_2 emissions using the Tier 4 Calculation Methodology. This requirement would replace the methods to calculate process-related and fuel combustion CO_2 emissions separately. To allow ARB to continue to separately estimate combustion emissions, the staff proposal continues to require cement plant operators to report fuel usage information by fuel type, whether or not CEMS are employed. This is consistent with the U.S. EPA MRR.

If not required to follow the Tier 4 methodology or otherwise choosing to report using CEMS, the operator must follow the U.S. EPA MRR's clinker-based method to determine process emissions. This method calculates CO_2 emissions from the quantity and composition of clinker produced, the quantity of CKD not recycled to the kiln during the manufacturing process, and the total organic carbon content of the raw materials consumed.

The clinker emission factor is based on the weight fraction of total CaO and total MgO in clinker. The methodology adopted non-calcined for non-carbonate terminology to reflect the anticipated trend of using calcium and magnesium materials in the kiln feed that provide calcium and magnesium to the clinker without creating carbonate-derived emissions. Non-calcined variables include any calcium or magnesium species in the clinker or CKD that did not undergo calcination and contribute to carbonate-derived emissions.

The CKD emission factor is based on both the non-calcined MgO and CaO content that remains in the CKD not recycled to the kiln. The CKD emission factor must be calculated only when cement plant operators do not recycle CKD back to the kiln. Most California cement plants recycle CKD back to the kiln; these operators would report zero emissions associated with CKD.

For reasons of inventory completeness, cement plants would be required to continue to report process-related emissions from the total organic carbon content in raw materials if CEMS are not utilized. It is especially relevant for cement plants that consume large

amounts of shale or fly ash and generate CKD, which may result in a higher percent of total organic carbon content in the raw materials entering the kiln.

The final proposal would require cement plants to calculate fuel combustion emissions based on the quantity and type of fuel burned annually if CEMS are not utilized. Cement plants would estimate stationary fuel combustion emissions using measured high heat value and carbon content depending on fuel type, as discussed in the stationary combustion section of this report.

In addition to reporting total carbon dioxide, methane, and nitrous oxide emissions, cement plant operators must report the annual quantity of clinker produced and the annual quantity of cement and clinker substitute consumed for blending. These data will allow ARB to calculate various efficiency metrics, such as the clinker efficiency metric, and would be required for benchmarking activities.

To fully support ARB programs, some additional modifications to the U.S. EPA MRR requirements were necessary. The primary differences are related to specific data accuracy requirements, the reporting of *de minimis* emissions, and what to do if required fuel use or other data are missing. These changes or limitations are discussed primarily in Sections II and VIII of this report.

C. Electric Power Entities

1. Background

The electricity sector has unique characteristics that are reflected in the staff proposal. The staff proposal is consistent with AB 32 requirements, the current ARB regulation (ARB MRR 2007), the proposed electricity sector protocol recommended jointly by the California Public Utilities Commission (CPUC) and the California Energy Commission (CEC) included as attachment D in the 2007 staff report (ARB ISOR 2007), and the Western Climate Initiative (WCI) *Final Essential Requirements of Mandatory Reporting* (WCI ERMR 2009). Staff's proposal incorporates the requirement in AB 32 and the WCI Partner jurisdictions' recommendation that emissions from electricity generated outside the WCI Partner jurisdictions but consumed within them be included in the program (WCI Program Design 2010).

Imported electricity accounted for 61 million MT of CO_2e, slightly more than the estimated 55 million MT of CO_2e from in-state electricity generation, as published in the 2008 ARB GHG inventory updated May 12, 2010 (ARB CA GHG Inventory for 2000-2008). Of the total greenhouse gas emissions associated with imported electricity, 43 percent was attributed to facilities outside California that are under contract or ownership obligation to serve California customers (ARB CA GHG Inventory for 2000-2008). The remaining 57 percent was attributed to sources that contribute to the western region power pool.

ARB staff presented preliminary regulatory concepts during the March 23, 2010 public workshop and California stakeholders provided further comments. The WCI Electricity

Team has addressed issues specific to the electricity sector related to the design and implementation of the WCI cap-and-trade program, including reporting requirements. ARB staff continues to participate in WCI Electricity Team discussions to assess policy mechanisms for addressing electricity sector emissions, examine technical issues related to the First Jurisdictional Deliverer (FJD) approach, and research issues related to reliability and electricity market efficiency. The Team has consulted with experts and stakeholders through conference calls, public meetings, and the release of written documents for review and comment. In addition, ARB coordinates an Interagency Electricity Sector Working Group with technical staff and management from the California Public Utilities Commission (CPUC), the California Energy Commission (CEC), and ARB. The Interagency Working Group has shared expertise and provided insight on various cap-and-trade program design considerations, including the necessary GHG reporting requirements recommended here to support the program. Taking into consideration this variety of input, and after careful analysis, staff prepared the final regulatory proposal.

2. Basis for Proposal

To provide a fair and equal regulatory approach, the proposed reporting regulation requires electric power entities to report emissions from imported electricity and in-state generation. This supports the point of regulation defined under the ARB cap-and-trade program as the "first deliverer of electricity." This term means either the owner or operator of an electricity generating facility in California or an electricity importer.

To provide regulatory certainty to electric power entities who receive power generated outside California from federal agencies, the definition of electricity importer clarifies that the Western Area Power Administration (WAPA) and the Bonneville Power Administration (BPA) are subject to the regulatory authority of the ARB under this article. Therefore, the definition of "first deliverer" and "electricity importer" are equivalent to the term "First Jurisdictional Deliverer (FJD)" used in the WCI cap-and-trade program design recommendations (WCI Program Design 2010). The WCI design recommendations provide for maintaining conceptual integrity while acknowledging the need to accommodate the regulatory process in each jurisdiction. The staff proposal has been developed to meet the needs of California's cap-and-trade program.

ARB is considering additional provisions that would clarify how GHG emissions from specified sources will be reported. To protect the environmental integrity of California's cap-and-trade program and provide a level playing field between in-state and out-of-state generation, it will be necessary to provide reasonable limitations on resource shuffling for imported electricity. Resource shuffling, in effect, appears to lower GHG emissions associated with electricity imported into California, while having no effect on, or creating an increase in, GHG emissions in the western region. In addition, ARB will need information to determine the extent to which resource shuffling, including shifting investments in existing resources serving the western region bulk system power pool, results in increased, decreased, or no net change in GHG emissions in the western region. Some resource shuffling can be minimized by limiting claims of existing lower-emitting resources and the associated GHG emissions for imported electricity. Some

resource shuffling is expected to be outside the regulatory authority of the ARB and will be minimized as ARB links with other jurisdictions in the Western Climate Initiative. In this proposal, accounting conventions for nuclear and large hydroelectric resources—existing, large capacity, fully committed resources—are specified to limit financial incentives to change the resource mix for imported electricity in ways that merely shift GHG emissions from California to other jurisdictions. This provision is consistent with the intent of the current ARB regulation (ARB MRR 2007, ARB ISOR 2007) and the WCI *Final Essential Requirements of Mandatory Reporting* (WCI ERMR 2009).

Renewable energy credits (RECs) cannot be used in GHG reporting. This is consistent with the intent of the California cap-and-trade program and the WCI cap-and-trade program (WCI RECs Accounting 2008, WCI RECs Announcement 2010) to provide a smooth transition to a future federal source-based program. A smooth transition requires that RECs from California renewable energy facilities do not have lesser value than RECs from out-of-state facilities, simply due to GHG attribution from the California cap-and-trade program.

3. Reporting Requirements and Methods

Electric power entities are required to continue reporting imported electricity, exported electricity, and retail sales, as applicable. In this proposed revised regulation, electric power entities will now also report emissions associated with imported and exported electricity, pursuant to the methods provided in the regulation. Reported emissions associated with imported electricity will inform the cap-and-trade program compliance requirement for first deliverers of electricity to hold allowances. Moreover, retail sales data are needed in order to inform the allocation of free allowances for retail providers. Exported electricity is reported for ARB inventory purposes. ARB is continuing to require retail providers to report out-of-state facility ownership share and contracts in order to evaluate whether anticipated decreases in future imported electricity emissions are due to resource shuffling or real emissions reductions in the western regional power system due to California's cap-and-trade program. The proposed revisions include a new requirement that the Western Area Power Administration (WAPA) report pump loads for the Central Valley Project and that the California Department of Water Resources (DWR) continue to report its State Water Project pump loads to support future analysis of GHG implications of water conservation and efficiency measures. Two reporting requirements of the current regulation (ARB MRR 2007) have been removed: (1) out-of-state facilities are no longer required to obtain verification of their emissions data reports, and (2) reporting wholesale electricity purchases and sales from California sources for electricity that is consumed in California is no longer required.

The proposed regulation includes minimum reporting requirements to support the California cap-and-trade program in maintaining the environmental integrity of the cap. For claims of specified sources of imported electricity and associated emissions, electric power entities must register those specified sources with ARB according to the regulation. ARB will calculate and publish emission factors for specified sources, including facilities, units, asset-controlling suppliers, and multi-jurisdictional retail providers. Calculation of emissions is based on primary technology and fuel type, as

well as a preferred hierarchy of available data sources. For out-of-state sources, GHG facility or unit reports that meet the requirements of this article may be submitted voluntarily to ARB. For specified facilities or units whose owners or operators do not voluntarily report under this article, but are subject to the U.S. EPA GHG Mandatory Reporting Regulation (USEPA MRR 2009-2010), ARB will accept CO_2e emissions reported to U.S. EPA. For specified facilities or units whose operators are not subject to the U.S. EPA GHG Mandatory Reporting Regulation, including cogeneration systems, ARB will accept CO_2e emissions calculated based on heat of combustion data reported to the Energy Information Administration (EIA 2010).

D. Electricity Generating and Cogeneration Units

1. Background

Currently in California, there are about 195 facilities whose primary sector is classified as electricity generation. In 2008, these electricity generating facilities emitted approximately 51 million metric tons of CO_2e, 13 percent of which are biogenic emissions and 2 percent of which came from geothermal processes. Approximately 86 percent of these emissions are attributed to electricity generating facilities with fossil fuel combustion emissions greater than 25,000 metric tons of CO_2e. Of the 195 facilities, about 30 produced emissions in the range of 10,000 to 25,000 metric tons of CO_2e per year. There are also 44 currently reporting facilities that emitted less than 10,000 tons of CO_2e per year. Data shown are from the ARB summary of GHG emissions reported for 2008 under the mandatory reporting program (ARB GHG Summary 2010).

In addition to pure electricity generation facilities, there are also 58 stand-alone cogeneration facilities producing mechanical or thermal energy and electricity, with capacity greater than 1 MW. In 2008, these cogeneration facilities reported emitting about 12 million metric tons of CO_2e. Approximately 99 percent of these emissions were attributed to facilities with greater than 25,000 tons of CO_2e of emissions (ARB GHG Summary 2010). In addition to these stand-alone cogeneration facilities, there are 102 facilities reporting under other industry sector categories that indicated cogeneration as a secondary sector. The cogeneration emissions from these facilities are accounted for as separate entries in reports submitted under primary sectors that include general stationary combustion, electricity generation, cement plants, petroleum refineries, and hydrogen plants.

Staff proposes the continued inclusion of electricity generating and cogeneration units for GHG reporting under the proposed revised regulation because of the significance of the emissions, the inclusion of the sectors in a proposed California cap-and-trade program, and because the facilities are also required to report under the U.S. EPA MRR (USEPA MRR 2009-2010).

As discussed in Section I, ARB staff also participated in extensive discussions with the other Western Climate Initiative (WCI) jurisdictions through the WCI Reporting Committee, to identify changes or limitations to U.S. EPA MRR requirements that would result in compliance grade emissions calculations for cap-and-trade while minimizing

any need to report different numbers than those reported to U.S. EPA. In March 2010, ARB staff presented current thinking on proposed requirements for electricity generating and cogeneration units at a public workshop, and received comments at the workshop and thereafter. Stakeholder comments on the WCI harmonization proposal (WCI HER 2010) were also reviewed by ARB and discussed with stakeholders and other state representatives on the WCI Reporting Committee. Taking into consideration this variety of input, staff prepared the final regulatory proposal.

2. Basis for Proposal

The staff proposal incorporates the U.S. EPA final reporting rule as the foundation for reporting requirements for the electricity generation and cogeneration units. Finalized in 2009 after an extensive public process, the U.S. EPA rule contains calculation methodologies that are often very similar (but not identical) to those adopted earlier by ARB after our own public process in 2007. By aligning with the wording of the U.S. EPA regulation as we develop requirements suitable for cap-and-trade, we are able to reduce duplication of effort, questions of interpretation, costs, and complexity for reporters. In most cases, GHG reports that meet the proposed ARB requirements would also meet U.S. EPA reporting requirements.

In developing the currently proposed ARB regulation, staff reviewed the U.S. EPA *Technical Support Document for Stationary Fuel Combustion Emissions: Proposed Rule for Mandatory Reporting of Greenhouse Gases* (USEPA TSD C 2009) and the *Response to Public Comments, Subpart D – Electricity Generation* (USEPA Comments D 2009). We evaluated the adopted federal GHG reporting requirements and methodologies (USEPA MRR 2009-2010) and compared them to the current ARB GHG reporting requirements for the sector (ARB MRR 2007). In addition, staff discussed with state and provincial colleagues in the WCI Reporting Committee whether each harmonized requirement adequately supported data needs for a cap-and-trade program.

In some cases it was necessary to apply changes or limitations to the U.S. EPA requirements to ensure that our proposed regulation fully meets ARB program needs. Generally, modifications to the U.S. EPA baseline were included to increase the accuracy of reported emissions or to provide additional specifications for when required data were not collected. These changes, which apply to most reporting sectors, are discussed below and in the sections on Calculation Methods for Stationary Combustion and Missing Data Substitution Procedures.

3. Reporting Requirements and Methods

There is a significant change proposed in regulation applicability that affects electricity generation and cogeneration units. The applicable reporting threshold would be raised from 2,500 metric tons CO_2e to 10,000 MT of CO_2e for these units. This relieves about 48 facilities of current emissions reporting requirements.

Beyond applicability, the proposed ARB reporting requirements for electricity generating and cogeneration units are similar to the U.S. EPA greenhouse gas emissions reporting

requirements. In general this means that units currently reporting under 40 CFR Part 75 would continue to do so, while operators of other units would estimate emissions using the specified methods for stationary fuel combustion sources referred to in section 95115 of the proposed regulation.

Under this proposal, California cogeneration and electricity generation units would usually calculate GHG emissions as specified in Subparts D and C of the U.S. EPA GHG reporting regulation (USEPA MRR 2009-2010). Units directed by U.S. EPA to Subpart C would report under those requirements as modified by the ARB staff proposal. For variable fuels, higher tiers in the U.S. EPA regulation are specified, consistent with WCI's harmonized requirements (WCI HER 2010), as detailed in Section III.A. of this report. Units reporting to U.S. EPA under Subpart D (like Subpart C) would report biomass and fossil CO_2 separately, even when not required to under Part 75.

Reporting would also be required for CO_2 and CH_4 emissions from geothermal generating units. Geothermal facilities would be required to submit a test plan for review and approval, rather than rely on a default emission factor that often results in inaccurate and non-representative emissions estimates for these facilities. There are unique characteristics for each geothermal reservoir, resulting in broad variation in the greenhouse gas contents of geothermal steam. Geothermal facilities are significant sources of GHGs and proposed for inclusion in reporting because AB 32 requires full coverage of the electricity sector.

Operators of hydrogen fuel cells at facilities otherwise subject to reporting would report on the amounts and types of feedstocks used, but would not be required to calculate emissions due to uncertainties in feedstock carbon content and the relative insignificance of fuel cell emissions.

Basic additional data would be included in emissions data reports, including nameplate capacity, net and gross power generated, and fuel consumption by fuel type. For cogeneration units, additional data would include useful thermal output and supplemental firing information. However, staff has proposed not to continue the current requirement for cogeneration facilities to distribute emissions between electricity and thermal outputs. At this point staff does not believe it is important for facilities to determine this information, which is often difficult for operators and complicated by the many variations in cogeneration facility configuration. It is possible the requirement will be reconsidered in the future if it is needed for allowance allocation or benchmarking purposes.

E. Petroleum Refineries

1. Background

The process of refining crude oil stocks to produce high quality transportation fuels and petrochemical products is a very energy intensive process. Nationwide, U.S. EPA estimates that petroleum refining accounted for about 7 percent of the total U.S. energy

consumption in 2007, making the sector the second highest industrial energy consumer (USEPA TSD Y). Similarly, in California the State's 21 petroleum refineries produce about 7 percent of the annual GHG emissions in the state – some 35.5 million metric tons of CO_2e in 2008 (ARB GHG Summary 2010). Because of the size and importance of refinery emissions, ARB included provisions for them to be reported in the regulation approved by the Board in late 2007.

As discussed in Section I, ARB staff also participated in extensive discussions with the other Western Climate Initiative (WCI) jurisdictions through the WCI Reporting Committee, to identify changes or limitations to U.S. EPA MRR requirements that would result in compliance grade emissions calculations for cap-and-trade while minimizing any need to report different numbers than those reported to U.S. EPA. In March 2010, ARB staff presented current thinking on proposed requirements for refineries at a public workshop, and received comments at the workshop and thereafter. Stakeholder comments on the WCI harmonization proposal (WCI HER 2010) were also reviewed by ARB and discussed with stakeholders and other state representatives on the WCI Reporting Committee. Taking into consideration this variety of input, staff prepared the final regulatory proposal.

2. Basis for Proposal

The staff proposal incorporates the U.S. EPA final reporting rule as the foundation for reporting requirements for the petroleum refining industry. Finalized in 2009 after an extensive public process, the U.S. EPA rule contains calculation methodologies that are often very similar (but not identical) to those adopted earlier by ARB after our own public process in 2007. By aligning with the wording of the U.S. EPA regulation as we develop requirements suitable for cap-and-trade, we are able to reduce duplication of effort, questions of interpretation, costs, and complexity for reporters. In most cases, GHG reports that meet the proposed ARB requirements would also meet U.S. EPA reporting requirements.

In developing the currently proposed ARB regulation, staff reviewed the U.S. EPA *Technical Support Document for the Petroleum Refining Sector: Proposed Rule for Mandatory Reporting of Greenhouse Gases* (USEPA TSD Y) and the *Response to Public Comments, Subpart Y – Petroleum Refineries* (USEPA Comments Y 2009). We evaluated the methodologies in the final U.S. EPA rule (USEPA MRR 2009-2010) and compared them to the current ARB GHG reporting requirements for the sector (ARB MRR 2007). In addition, staff discussed with state and provincial colleagues in the WCI Reporting Committee whether each harmonized requirement adequately supported data needs for a cap-and-trade program. As a result of this harmonization effort, the proposed revised regulation includes several variations from the final EPA rule that were deemed necessary to provide the accuracy and consistency required for a cap-and-trade program.

3. Reporting Requirements and Methods

The U.S. EPA final rule contains GHG calculation methodologies for the refinery related source types and gases show in Table III-1.

Table III-1. Refinery Related Source Types

Source	*CO_2*	*CH_4*	*N_2O*
Stationary Combustion	X	X	X
Flares	X	X	X
Catalytic cracking/Fluid Coking	X	X	X
Fluid coking - flexicoker	X	X	X
Catalytic reforming	X	X	X
Sulfur recovery	X		
Coke calcining	X	X	X
Asphalt blowing	X	X	
Delayed coking		X	
Process vents	X	X	X
Uncontrolled blowdowns		X	
Equipment leaks		X	
Storage tanks		X	

Among the 13 source types in the table above, the available emissions calculation methods for three relatively minor sources are considered to have insufficient rigor for inclusion in a cap-and-trade program. For asphalt blowing, equipment leaks, and storage tanks, staff did not find cost-effective and accurate methods for quantifying emissions. Staff investigated the latest U.S. EPA methodologies in the draft MRR along with industry standard publications such as the 2009 API Compendium (API, 2009). In the case of equipment leaks, for example, while new technology such as high volume samplers may provide accurate data for leaking fugitive components, such measurement techniques are often very costly and time and labor intensive. In addition, once emissions rates for leaking components are determined, reporters would still be faced with the difficult if not impossible task of determining the length of time the leak has occurred in order to calculate an annual emissions estimate suitable for cap-and-trade. While emissions from these three sources would still be reported using the available methods in the U.S. EPA rule, ARB staff has recommended that these emissions not be subject to a compliance obligation under the proposed cap-and-trade program.

For the remaining source types, staff has proposed that the revised regulation include methods as described below. Several of the proposed petroleum refinery emissions methodologies reflect minor modifications to the U.S. EPA MRR that ARB staff and WCI jurisdictions believe are essential to support the rigorous and accurate GHG accounting program needed for market trading. These modifications are consistent with WCI's proposed harmonized requirements (WCI HER 2010) and are discussed below.

CO_2 from Fuel Combustion. Operators would use methodologies that account for the carbon variability of fuels. The regulation permits the use of Tier 1 methods only for *de minimis* emissions and certain standardized fuels (see Stationary Fuel Combustion section of this report). Monitoring, data and records requirements are altered as necessary to align with the selected stationary combustion methods. California refineries are provided until January 1, 2013 to establish equipment and procedures for daily sampling and analysis of refinery fuel gas if not already in place. (The U.S. EPA rule requires daily sampling of refinery fuel gas when equipment is in place, and all but two refineries currently reporting in California have been required to perform daily analyses.)

Calculating CO_2 from Flares. For normal flare operations operators would use the more accurate of two methods provided in the U.S. EPA MRR. For start-up, shutdown and malfunction (SSM) periods during which the operator was unable to measure the parameters required, they must determine the quantity of gas discharged to the flare separately for each SSM period. Engineering calculations and process knowledge are then used to estimate the carbon content of flared gas, as required in the U.S. EPA MRR. Data reporting requirements would also be modified to align with this change.

Calculating CO_2 from FCCUs and Fluid Coking. Operators would not be permitted to apply alternative calculation methods for units under the 10,000 barrels per stream day. The threshold in the U.S. EPA MRR was found to be too high, resulting in too much uncertainty for significant quantities of GHG emissions. This limitation also promotes consistency across the range of refineries in California.

Calculating CH_4 from Delayed Coking Units. The U.S. EPA MRR allows operators to use default values for two parameters: volumetric void fraction of the coking vessel and the average mole fraction of methane in the vessel at the time of depressurization. Under the staff proposal, operators would calculate volumetric void volume and measure the mole fraction of methane in the coking vessel gas twice annually. These changes are designed to generate more accurate and consistent data.

Uncontrolled Blowdown Systems. The U.S. EPA MRR provides two methods for calculating methane emissions from uncontrolled blowdowns: (1) use a default emission factor, or (2) use the process vent emission calculation methodology. The staff proposal would require that operators use the more precise process vent emissions methodology. Data reporting requirements have been modified to align with thi- change.

Records that Must be Retained. The staff proposal includes language which requires that operators retain data required to demonstrate that process vent emissions do not exceed specified thresholds for methane and carbon dioxide content.

Missing Data Substitution Requirements. The proposed revised regulation refers operators to the missing data substitution procedures for stationary combustion and

CEMS sources in section 95129 of the regulation, while such procedures for separate refinery process emissions are specified in the refineries section of the regulation. In both cases progressively more stringent requirements apply as more data are missing. The data substitution procedures, based on those in U.S. EPA's successful Acid Rain Program, are designed to provide a strong incentive for reporters to generate accurate and complete GHG accounting with as little data substitution as possible.

F. Hydrogen Production

1. Background

Hydrogen plays a central role in the production of clean low sulfur transportation fuels in California. Thirteen of the 21 petroleum refineries in California produce hydrogen on-site, and another six merchant hydrogen plants produce and supply hydrogen to California petroleum refineries (ARB GHG Summary 2010). The production of hydrogen generates large quantities of carbon dioxide derived from the wide variety of hydrocarbon feedstocks that serve as a hydrogen source. Because of the size and importance of hydrogen production emissions, ARB included provisions for them to be reported in the regulation approved by the Board in late 2007.

As discussed in Section I, ARB staff also participated in extensive discussions with the other Western Climate Initiative (WCI) jurisdictions through the WCI Reporting Committee, to identify changes or limitations to U.S. EPA MRR requirements that would result in compliance grade emissions calculations for cap-and-trade while minimizing any need to report different numbers than those reported to U.S. EPA. In March 2010, ARB staff presented current thinking on proposed requirements for hydrogen production at a public workshop, and received comments at the workshop and thereafter. Stakeholder comments on the WCI harmonization proposal (WCI HER 2010) were also reviewed by ARB and discussed with stakeholders and other state representatives on the WCI Reporting Committee. Taking into consideration this variety of input, staff prepared the final regulatory proposal.

2. Basis for Proposal

The staff proposal incorporates the U.S. EPA final reporting rule as the foundation for reporting requirements for hydrogen production facilities. Finalized in 2009 after an extensive public process, the U.S. EPA rule contains calculation methodologies that are often very similar (but not identical) to those adopted earlier by ARB after our own public process in 2007. By aligning with the wording of the U.S. EPA regulation as we develop requirements suitable for cap-and-trade, we are able to reduce duplication of effort, questions of interpretation, costs, and complexity for reporters. In most cases, GHG reports that meet the proposed ARB requirements would also meet U.S. EPA reporting requirements.

In developing the currently proposed ARB regulation, staff reviewed the *U.S. EPA Technical Support Document for the Hydrogen Production Sector: Proposed Rule for*

Mandatory Reporting of Greenhouse Gases (USEPA TSD P) and the *Response to Public Comments, Subpart P-- Hydrogen Production* (USEPA Comments P 2009). We evaluated the methodologies in the final U.S. EPA rule (USEPA MRR 2009-2010) and compared them to the current ARB GHG reporting requirements for the sector (ARB MRR 2007). In addition, staff discussed with state and provincial colleagues in the WCI Reporting Committee whether each harmonized requirement adequately supported data needs for a cap-and-trade program. As a result of this harmonization effort, the proposed revised regulation includes several variations from the final U.S. EPA rule that were deemed necessary to provide the accuracy and consistency required for a cap-and-trade program.

3. Reporting Requirements and Methods

Hydrogen production facilities are required to reporting both stationary combustion and process related GHG emissions. The hydrogen production reporting requirements in the staff proposal reflect several modifications to the U.S. EPA MRR, consistent with the WCI harmonization proposal, as discussed below.

CO_2 from Fuel Combustion. Operators would use methodologies that account for the carbon variability of fuels. The regulation permits the use of Tier 1 methods only for *de minimis* emissions and certain standardized fuels (see Stationary Fuel Combustion section of this report). Monitoring, data and records requirements are altered as necessary to align with the selected stationary combustion methods.

Sampling Frequencies. Because operators use a wide variety of feedstocks, which may often vary in carbon content, the proposal requires daily sampling of most feedstocks and weighting of carbon content values consistent with the prescribed frequency. Monthly sampling would be allowed for pipeline quality natural gas. Monthly testing of composite daily samples would also be permitted for liquid and solid fuels. The regulation provides users with a methodology for determining the monthly weighted feedstock carbon content based on this daily sampling regime.

Data Reporting Requirements. The operator would be required to report the amount of carbon in unconverted feedstock for which GHG emissions are calculated and reported under other requirements in the regulation (e.g., carbon in a flared waste stream). This is essential to preventing the double-counting of a cap-and-trade compliance obligation.

Missing Data Substitution Requirements. The proposed revised regulation refers operators to the missing data substitution procedures for stationary combustion and CEMS sources in section 95129 of the regulation, while such procedures for separate hydrogen production process emissions are specified in the hydrogen production section of the regulation. In both cases, progressively more stringent requirements apply as more data are missing. The data substitution procedures, based on those in U.S. EPA's successful Acid Rain Program, are designed to provide a strong incentive for reporters to generate accurate and complete GHG accounting with as little data substitution as possible.

G. Glass Production

1. Background

Eight of California's thirteen glass production facilities, with individual emissions exceeding 25,000 metric tons of CO_2e, produced just over 550,000 metric tons of combustion-related CO_2e emissions in 2008 (ARB GHG Summary 2010). An additional amount of process-related GHG emissions were emitted into the atmosphere that year from the calcination of carbonate-based raw materials to produce various glass products. However, those emissions were not reported under the current mandatory reporting regulation (ARB MRR 2007), which requires glass production facilities to report according to stationary combustion requirements only.

Staff is proposing to include glass production process emissions in the revised ARB MRR. This would also capture combustion emissions from several facilities currently below reporting thresholds. Glass production facilities are a significant contributor to GHG emissions worldwide, and are included in the United States U.S. EPA MRR (USEPA MRR 2009-2010).

As discussed in Section I, ARB staff also participated in extensive discussions with the other Western Climate Initiative (WCI) jurisdictions through the WCI Reporting Committee, to identify changes or limitations to U.S. EPA MRR requirements that would result in compliance grade emissions calculations for cap-and-trade while minimizing any need to report different numbers than those reported to U.S. EPA. In March 2010, ARB staff presented current thinking on proposed requirements at a public workshop, and received comments at the workshop and thereafter. Stakeholder comments on the WCI harmonization proposal (WCI HER 2010) were also reviewed by ARB and discussed with stakeholders and other state representatives on the WCI Reporting Committee. Taking into consideration this variety of input, staff prepared the final regulatory proposal.

2. Basis for Proposal

The staff proposal incorporates the U.S. EPA final reporting rule as the foundation for reporting requirements for the glass industry. The U.S. EPA rule was finalized in 2009 after an extensive public process. By aligning with the wording of the U.S. EPA regulation as we develop requirements suitable for cap-and-trade, we are able to reduce duplication of effort, questions of interpretation, costs, and complexity for reporters. In most cases GHG reports that meet the proposed ARB requirements would also meet U.S. EPA reporting requirements.

In developing the currently proposed ARB regulation, staff reviewed U.S. EPA's *Technical Support Document for the Glass Manufacturing Sector* (U.S. EPA TSD N 2009) and the *Response to Public Comments, Subpart N- Glass Production* (U.S. EPA Comments N 2009). We evaluated the adopted federal GHG reporting requirements and methodologies (USEPA MRR 2009-2010) for glass production and compared them to the current ARB MRR requirements (ARB MRR 2007).

As mentioned above, current ARB reporting requirements for glass manufacturing requires the reporting of stationary combustion emissions only. The U.S. EPA requirements that we propose to add to California requirements include a method to calculate and report process emissions associated with glass manufacturing. In addition, U.S. EPA MRR incorporates, and the staff proposal includes, methods to more clearly delineate the emissions from fossil and biogenic sources of combustion emissions, and the specific sources of those emissions. These are positive enhancements to collect more complete and accurate GHG emissions and other data from this industrial sector.

In addition, staff discussed with state and provincial colleagues in the WCI Reporting Committee whether each harmonized requirement adequately supported data needs for a cap-and-trade program. In some cases it was necessary to modify federal requirements to ensure that our proposed regulation fully meets ARB program needs. Generally, modifications to the U.S. EPA regulation were included to increase accuracy or to provide additional specifications for the replacement of missing analytical data. These changes apply to most reporting sectors and are described in the sections on Stationary Fuel Combustion and Missing Data Substitution Procedures.

3. Reporting Requirements and Methods

As described, the proposed regulation for glass manufacturing would substantially mirror the U.S. EPA MRR requirements. Under the staff proposal, all California glass manufacturing plants that surpass the reporting threshold would be required to report combined process-related and combustion CO_2 emissions from the production of glass using the Tier 4 (CEMS) methodology, or separately report combustion emissions and process-related CO_2 emissions from glass production using the raw material input-based method specified in 40 CFR §98.143(b)(2). Glass plants would also be required to report annual CO_2, biomass-derived CO_2, N_2O, and CH_4 emissions from fuel combustion, fuel consumption, the annual quantity of carbonate-based raw materials, the annual quantity of glass product(s) produced, and other specified data.

If certain conditions specified in the federal rule are met (40 CFR §98.33(b)(4)(ii) or (b)(4)(iii)), then the operator must determine CO_2 emissions using the Tier 4 Calculation Methodology. This requirement would replace the methods to separately calculate process-related and fuel combustion CO_2 emissions. To allow ARB to continue to separately estimate combustion emissions, the staff proposal continues to require operators to report fuel usage information by fuel type, whether or not CEMS are employed. This is consistent with the U.S. EPA MRR.

If not required to follow the Tier 4 methodology or otherwise choosing to report using CEMS, the operator must follow the U.S. EPA MRR's glass raw material input-based method to calculate process emissions. This method calculates CO_2 emissions from the glass furnace based on the amount of each type of carbonate-based raw material charged to the furnace, the mass fraction of the carbonate-based mineral in each type of carbonate-based raw material consumed, the specified emission factor for each type

of carbonate-based raw material consumed, and the fraction of calcination achieved for each type of carbonate-based material consumed.

The final proposal would require glass manufacturing plants to calculate fuel combustion CO_2, biomass-derived CO_2, N_2O, and CH_4 emissions based on the quantity and type of fuel burned annually if CEMS are not utilized. Glass plants would estimate stationary fuel combustion emissions using measured high heat value or carbon content depending on fuel type, as discussed in the stationary combustion section of this report.

To fully support ARB programs, some additional modifications to the U.S. EPA MRR requirements were necessary. We propose to collect some additional annual glass product output data to support benchmarking activities. Additional differences are related to specific data accuracy requirements, the reporting of *de minimis* emissions, and what to do if required fuel use or other data are missing. These changes or limitations are discussed elsewhere in this report.

H. Lime Manufacturing

1. Background

Lime manufacturing in California resulted in just over 25,000 metric tons of combustion-related CO_2e emissions in 2008 (ARB GHG Summary 2010). A slightly larger amount of process-related GHG emissions were emitted into the atmosphere that year from limestone calcination to produce lime. However, those emissions were not reported under the current mandatory reporting regulation (ARB MRR 2007), as under the current regulation lime manufacturers are required only to report stationary combustion emissions.

Staff has proposed the inclusion of lime manufacturing process emissions as well as combustion emissions in the revised regulation. Lime manufacturing is a significant contributor to GHG emissions worldwide (U.S. EPA TSD S 2009), and is included in the U.S. EPA MRR (USEPA MRR 2009-2010).

As discussed in Section I, ARB staff also participated in extensive discussions with the other Western Climate Initiative (WCI) jurisdictions through the WCI Reporting Committee, to identify changes or limitations to U.S. EPA MRR requirements that would result in compliance grade emissions calculations for cap-and-trade while minimizing any need to report different numbers than those reported to U.S. EPA. In March 2010, ARB staff presented current thinking on proposed requirements at a public workshop, and received comments at the workshop and thereafter. Stakeholder comments on the WCI harmonization proposal (WCI HER 2010) were also reviewed by ARB and discussed with stakeholders and other state representatives on the WCI Reporting Committee. Taking into consideration this variety of input, staff prepared the final regulatory proposal.

2. Basis for Proposal

The staff proposal incorporates the U.S. EPA final reporting rule as the foundation for reporting requirements for the lime industry. The U.S. EPA rule was finalized in 2009 after an extensive public process. By aligning with the wording of the U.S. EPA regulation as we develop requirements suitable for cap-and-trade, we are able to reduce duplication of effort, questions of interpretation, costs, and complexity for reporters. In most cases, GHG reports that meet the proposed ARB requirements would also meet U.S. EPA reporting requirements.

In developing the currently proposed ARB regulation, staff reviewed *U.S. EPA's Technical Support Document for the Lime Manufacturing Sector* (U.S. EPA TSD S 2009) and the *Response to Public Comments, Subpart S- Lime Manufacturing* (U.S. EPA Comments S 2009). We evaluated the adopted federal GHG reporting requirements and methodologies (USEPA MRR 2009-2010) for lime production and compared them to the current ARB MRR requirements (ARB MRR 2007).

The existing ARB reporting requirements for lime manufacturing require the reporting of stationary combustion emissions only. The U.S. EPA requirements which we propose to adopt include methods to more clearly delineate the emissions from fossil fuel and biogenic sources of combustion emissions, and the specific sources of those emissions. In addition, U.S. EPA incorporates a method to compute and report process emissions associated with lime manufacturing. These are positive enhancements to collect more complete and accurate GHG emissions and other data from this industrial sector.

In addition, staff discussed with state and provincial colleagues in the WCI Reporting Committee whether each harmonized requirement adequately supported data needs for a cap-and-trade program. In some cases, it was necessary to modify federal requirements to ensure that our proposed regulation fully meets ARB program needs. Generally, modifications to the U.S. EPA MRR were included to increase accuracy or to provide additional specifications for when required data were not collected. These changes, which apply to most reporting sectors, are described in the sections on Stationary Fuel Combustion and Missing Data Substitution.

3. Reporting Requirements and Methods

As described, the proposed regulation for lime manufacturing would substantially mirror the U.S. EPA MRR requirements. Under the staff proposal, California's lime manufacturing plant would be required to report combined process-related and combustion CO_2 emissions from the production of lime, calcined lime byproduct/waste that was sold, and calcined lime byproduct/waste that was not sold by using the Tier 4 (CEMS) methodology, or separately report combustion emissions and process-related CO_2 emissions from lime products and byproducts using the lime-based method specified in 40 CFR §98.193(b)(2). Lime plants would also be required to report annual CO_2, biomass-derived CO_2, N_2O, and CH_4 emissions from fuel combustion, fuel consumption, the quantity of raw materials consumed, the quantity of lime product produced, the quantity of lime by product/waste that was sold and was not sold, and other specified data.

If the conditions specified in 40 CFR §98.33(b)(4)(ii) or (b)(4)(iii) are met, then the operator must determine CO_2 emissions using the Tier 4 Calculation Methodology. This requirement would replace the methods to separately calculate process-related and fuel combustion CO_2 emissions. To allow ARB to continue to separately estimate combustion emissions, the staff proposal continues to require lime plant operators to report fuel usage information by fuel type, whether or not CEMS are employed. This is consistent with the U.S. EPA MRR.

If not required to follow the Tier 4 methodology or otherwise choosing to report using CEMS, the operator must follow the U.S. EPA MRR's lime-based method to calculate process emissions. This method calculates process CO_2 emissions from the quantity of lime and calcined lime product/waste produced during the manufacturing process, the CaO and MgO content of each type of material, and the specified stoichiometric ratios.

Three total emissions factors must be determined, one for each type of lime produced, calcined lime byproduct/ waste that was sold, and calcined lime byproduct/ waste that was not sold. Each emission factor is based on the specified stoichiometric ratio and the chemical composition (percent total CaO and MgO) of each type of lime and each type of calcined byproduct/waste that was sold or not sold.

The final proposal would require lime manufacturing plants to calculate fuel combustion CO_2, biomass-derived CO_2, N_2O, and CH_4 emissions based on the quantity and type of fuel burned annually if CEMS are not utilized. Lime plants would estimate stationary fuel combustion emissions using measured high heat value or carbon content depending on fuel type, as discussed in the stationary combustion section of this report.

To fully support ARB programs, some additional modifications to the U.S. EPA MRR requirements were necessary. The primary differences are related to specific data accuracy requirements, the reporting of *de minimis* emissions, and what to do if required fuel use or other data are missing. These changes or limitations are discussed elsewhere in this report.

I. Nitric Acid Production

1. Background

Two facilities in California produce nitric acid, which is commonly used to manufacture nitrogen-based fertilizer and explosives (U.S. EPA TSD V 2009). The production pathway begins with the stepwise catalytic oxidation of ammonia, followed by a series of additional chemical reactions to ultimately make nitric acid (U.S. EPA TSD V 2009). Greenhouse gas emissions reporting was not triggered for either facility by the current ARB regulation because their combustion emissions, which were negligible, did not surpass the 25,000 metric tons of CO_2e reporting threshold (ARB GHG Summary 2010). The current regulation does not include reporting requirements for the principal source of GHG emissions at nitric acid production facilities - nitrous oxide (N_2O) process emissions (ARB MRR 2007).

Staff has proposed the inclusion of nitric acid production facilities in the ARB MRR to capture their nitrous oxide process emissions. Nitrous oxide has a global warming potential of 310 metric tons of CO_2 equivalent emissions per metric ton of N_2O, making it a very potent greenhouse gas (U.S. EPA TSD V 2009). Nitric acid production facilities are required to report under the U.S. EPA MRR (USEPA MRR 2009-2010).

As discussed in Section I, ARB staff also participated in extensive discussions with the other Western Climate Initiative (WCI) jurisdictions through the WCI Reporting Committee, to identify changes or limitations to U.S. EPA MRR requirements that would result in compliance grade emissions calculations for cap-and-trade while minimizing any need to report different numbers than those reported to U.S. EPA. In March 2010, ARB staff presented current thinking on proposed requirements at a public workshop, and received comments at the workshop and thereafter. Stakeholder comments on the WCI harmonization proposal (WCI HER 2010) were also reviewed by ARB and discussed with stakeholders and other state representatives on the WCI Reporting Committee. Taking into consideration this variety of input, staff prepared the final regulatory proposal.

2. Basis for Proposal

The staff proposal incorporates the U.S. EPA final reporting rule as the foundation for reporting requirements for nitric acid producers. The U.S. EPA rule was finalized in 2009 after an extensive public process. By aligning with the wording of the U.S. EPA regulation as we develop requirements suitable for cap-and-trade, we are able to reduce duplication of effort, questions of interpretation, costs, and complexity for reporters. In most cases, GHG reports that meet the proposed ARB requirements would also meet U.S. EPA reporting requirements.

In developing the currently proposed ARB regulation, staff reviewed U.S. EPA's *Technical Support Document for the Nitric Acid Production Sector* (U.S. EPA TSD V 2009) and the *Response to Public Comments, Subpart V- Nitric Acid Production* (U.S. EPA Comments V 2009). We evaluated the adopted federal GHG reporting requirements and methodologies (USEPA MRR 2009-2010) for nitric acid production and compared them to the current ARB MRR requirements (ARB MRR 2007).

The existing ARB reporting requirements for nitric acid production facilities require the reporting of stationary combustion emissions only, as opposed to process emissions, if they surpass the 25,000 MT of CO_2e reporting threshold. In California, they do not (ARB GHG Summary 2010. The U.S. EPA MRR requirements that we propose to adopt incorporate a method to compute and report process emissions associated with nitric acid production. These are positive enhancements to collect more complete and accurate GHG emissions and other data from this industrial sector.

In addition, staff discussed with state and provincial colleagues in the WCI Reporting Committee whether each harmonized requirement adequately supported data needs for a cap-and-trade program. In some cases, it was necessary to modify federal

requirements to ensure that our proposed regulation fully meets ARB program needs. Generally, modifications to the U.S. EPA baseline were included to increase stringency or to provide additional specifications for when required data were not collected. These changes, which apply to most reporting sectors, are described in the sections on Missing Data Substitution Procedures and Calculation Methods for Stationary Combustion.

3. Reporting Requirements and Methods

As described, the proposed regulation for nitric acid production would substantially mirror the U.S. EPA MRR requirements. Under the staff proposal, all California nitric acid production facilities would be required to report process-related N_2O emissions, as well as any combustion emissions from the production of nitric acid. Combustion emissions would be reported according to the specified methods, including CO_2, biomass-derived CO_2, N_2O, and CH_4 emissions and fuel consumption. Nitrous oxide process emissions would be reported using a site-specific emissions factor and production rate data, or the operator may request approval from ARB's Executive Officer to use an alternative method, such as the use of N_2O CEMS, for determining nitrous oxide emissions. (This parallels a similar process involving the U.S. EPA administrator.) Annual nitric acid production data and other specified data would also be reported.

If not requesting and receiving approval to use an alternative method, the operator must determine the nitrous oxide emissions using the specified method. To determine the nitrous oxide emission factor, an annual performance test must be conducted. Such a test requires the operator to measure (using the specified methods) the nitrous oxide emissions from the absorber tail gas vent for each nitric acid train, the nitrous oxide concentration, and the nitric acid production rate. If applicable, the destruction efficiency and the abatement factor for each nitrous oxide abatement technology must be determined according to the specified methods.

The final proposal would require nitric acid production facilities to calculate fuel combustion CO_2, biomass-derived CO_2, N_2O, and CH_4 emissions based on the quantity and type of fuel burned annually. These facilities would estimate stationary fuel combustion emissions using measured high heat value and carbon content depending on fuel type, as discussed in the stationary combustion section of this report.

To fully support ARB programs, some additional modifications to the U.S. EPA MRR requirements were necessary. The primary differences are related to specific data accuracy requirements, the reporting of *de minimis* emissions, and what to do if required fuel use or other data are missing. These changes or limitations are discussed elsewhere in this report.

J. Pulp and Paper Manufacturing

1. Background

In California, pulp and paper manufacturing facilities generated about 800,000 metric tons of CO_2 emissions in 2008, from combustion emissions only. Combustion emissions from each of the five California pulp and paper facilities ranged from about 65,000 to about 300,000 metric tons of CO_2e per year (ARB GHG Summary 2010). Staff proposes the continued inclusion of pulp and paper manufacturing for GHG reporting under the proposed ARB MRR because of the significance of these emissions, the inclusion of the pulp and paper facilities in a proposed California cap-and-trade program, and because the facilities are also required to report under the U.S. EPA MRR (USEPA MRR 2009-2010).

As discussed in Section I, ARB staff also participated in extensive discussions with the other Western Climate Initiative (WCI) jurisdictions through the WCI Reporting Committee, to identify changes or limitations to U.S. EPA MRR requirements that would result in compliance grade emissions calculations for cap-and-trade while minimizing any need to report different numbers than those reported to U.S. EPA. In March 2010, ARB staff presented current thinking on proposed requirements at a public workshop, and received comments at the workshop and thereafter. Stakeholder comments on the WCI harmonization proposal (WCI HER 2010) were also reviewed by ARB and discussed with stakeholders and other state representatives on the WCI Reporting Committee. Taking into consideration this variety of input, staff prepared the final regulatory proposal.

2. Basis for Proposal

The staff proposal incorporates the U.S. EPA final reporting rule as the foundation for reporting requirements for the pulp and paper industry. The U.S. EPA rule was finalized in 2009 after an extensive public process. By aligning with the wording of the U.S. EPA regulation as we develop requirements suitable for cap-and-trade, we are able to reduce duplication of effort, questions of interpretation, costs, and complexity for reporters. In most cases, GHG reports that meet the proposed ARB requirements would also meet U.S. EPA reporting requirements.

In developing the proposed revised ARB regulation, staff reviewed *U.S. EPA's Technical Support Document for the Pulp and Paper Sector* (USEPA TSD AA 2009) and the *Response to Public Comment, Subpart AA – Pulp and Paper Manufacturing* (USEPA Comments AA 2009). We evaluated the adopted federal GHG reporting requirements and methodologies (USEPA MRR 2009-2010) for pulp and paper manufacturing and compared them to the current ARB GHG reporting requirements (ARB MRR 2007). In addition, staff discussed with state and provincial colleagues in the WCI Reporting Committee whether each harmonized requirement adequately supported data needs for a cap-and-trade program.

The current ARB reporting requirements for pulp and paper manufacturing require reporting of general combustion emissions only. The U.S. EPA requirements, which we

propose to adopt, add methods to more clearly delineate the emissions from fossil fuel and biogenic sources of combustion emissions, and the specific sources of those emissions. In addition, U.S. EPA adds a method to compute and report process emissions from the use of makeup chemicals. The inclusion of these process emissions is a key difference between the current and proposed ARB reporting regulations. Because pulp and paper facilities must already collect and report all of the data needed to comply with the federal requirements, ARB's adoption of the more comprehensive U.S. EPA requirements should not impose a major new burden on California facilities.

In some cases, however, it was necessary to modify the U.S. EPA requirements to ensure that our proposed regulation fully meets ARB program needs. Generally, modifications to the U.S. EPA baseline were included to increase the accuracy of reported emissions or to provide additional specifications for what to do when failures occur in data collection. These changes, which apply to most reporting sectors, are discussed below and in the sections on Calculation Methods for Stationary Combustion and Missing Data Substitution Procedures.

3. Reporting Requirements and Methods

As mentioned, the proposed ARB reporting requirements for pulp and paper manufacturing substantially mirror the U.S. EPA greenhouse gas emissions reporting requirements. This includes reporting CO_2, biogenic CO_2, CH_4, and N_2O emissions from general combustion sources, biomass fired combustion units, chemical recovery furnaces/combustion units, and pulp mill lime kilns. Pulp and paper facilities would also be required to report CO_2 process emissions from makeup chemicals, quantities and characteristics of fuels used, spent liquor solids combusted, quantities of $NaCO_3$ and $CaCO_3$ used, annual production, and other data.

Under this proposal, California pulp and paper manufacturing facilities would calculate GHG emissions as specified in Subpart AA of the U.S. EPA MRR (USEPA MRR 2009-2010) and comply with each of the calculation methods and reporting requirements identified, with specific modifications. In particular, while Subpart AA allows pulp and paper facilities to calculate and report combustion emissions using default emission factors for any type of fuel, the staff proposal would require them to follow method selection by fuel type as required of other industrial facilities. This would provide sufficient accuracy to support inclusion of these facilities in a cap-and-trade program, and equitable treatment across industry types.

The method selection for stationary combustion sources is explained in the Stationary Fuel Combustion section of this report, and was developed in close consultation with representatives of other jurisdictions through the WCI Reporting Committee. For standardized homogenous fuels, lower tiers may be used, which allow use of default values to estimate emissions. For more variable fuels, higher tier requirements are specified, which may require fuel sampling and testing or use of a CEMS to ensure that the emissions are estimated accurately.

To fully support ARB programs, some additional modifications to the U.S.EPA MRR requirements were necessary. The primary differences are related to specific data accuracy requirements, the reporting of *de minimis* emissions, and what to do if required fuel use or other data are missing. These changes or limitations are discussed elsewhere in this report. We also propose to collect some specified product output data to support benchmarking activities.

K. Iron and Steel Production

1. Background

Five iron and steel facilities in California are currently subject to GHG reporting under the existing ARB regulation. Under the proposed regulation, each of these facilities would continue to report their stationary fuel combustion emissions, which ranged from just over 25,000 metric tons to about 165,000 metric tons CO_2 in 2008 (ARB GHG Summary 2010). However, facilities with certain operations, such as the use of an electric arc furnace, are subject to additional requirements to report process emissions under the U.S. EPA mandatory reporting final rule (USEPA MRR 2009-2010). One facility in California uses an electric arc furnace, and under the staff proposal would also report these emissions to ARB.

Most of the other "steel" facilities in the state purchase steel slabs from outside suppliers and use these slabs to manufacture rolled steel and other products. Because these other facilities are only heating the slabs, they are subject only to reporting their stationary combustion emissions, as required by section 95115 of the proposed revised regulation and explained in the Stationary Fuel Combustion section of this report.

As discussed in Section I, ARB staff also participated in extensive discussions with the other Western Climate Initiative (WCI) jurisdictions through the WCI Reporting Committee, to identify changes or limitations to U.S. EPA MRR requirements that would result in compliance grade emissions calculations for cap-and-trade while minimizing any need to report different numbers than those reported to U.S. EPA. In March 2010, ARB staff presented current thinking on proposed requirements at a public workshop, and received comments at the workshop and thereafter. Following this, informal stakeholder meetings and phone calls were held to discuss the regulation revisions pertinent to the iron and steel industry. Stakeholder comments on the WCI harmonization proposal (WCI HER 2010) were also reviewed by ARB and discussed with stakeholders and other state representatives on the WCI Reporting Committee. Taking into consideration this variety of input, staff prepared the final regulatory proposal.

2. Basis for Proposal

The staff proposal incorporates the U.S. EPA final reporting rule as the foundation for reporting requirements for the iron and steel industry. The U.S. EPA rule was finalized in 2009 after an extensive public process. By aligning with the wording of the U.S. EPA regulation as we develop requirements suitable for cap-and-trade, we are able to reduce duplication of effort, questions of interpretation, costs, and complexity for

reporters. In most cases, GHG reports that meet the proposed ARB requirements would also meet U.S. EPA reporting requirements.

In developing the currently proposed ARB regulation, staff reviewed *U.S. EPA's Technical Support Document for the Iron and Steel Sector* (USEPA TSD Q 2009) and the *Response to Public Comments, Subpart Q – Iron and Steel Production* (USEPA Comments Q 2009). We evaluated the adopted federal GHG reporting requirements and methodologies (USEPA MRR 2009-2010) and compared them to the current ARB GHG reporting requirements for the sector (ARB MRR 2007). In addition, staff discussed with state and provincial colleagues in the WCI Reporting Committee whether each harmonized requirement adequately supported data needs for a cap-and-trade program.

The current ARB reporting requirements for iron and steel production require reporting of general combustion emissions only. The U.S. EPA requirements that we propose to adopt would add methods to compute CO_2 process emissions from specified activities. These are positive enhancements to collect more complete and accurate GHG emissions and other data from iron and steel industry.

In some cases it was necessary to modify the baseline U.S. EPA requirements to ensure that our proposed regulation fully meets ARB program needs. Generally, modifications to the U.S. EPA baseline were included to increase accuracy or to provide additional specifications for when required data were not collected. These changes, which apply to most reporting sectors, are discussed below and in the sections on Stationary Fuel Combustion and Missing Data Substitution Procedures.

3. Reporting Requirements and Methods

As mentioned, the proposed ARB reporting requirements for iron and steel production substantially mirror the U.S. EPA greenhouse gas emissions reporting requirements. In addition to reporting of stationary fuel combustion emissions facilities would report specified process emissions from any taconite indurating furnace, basic oxygen furnace, non-recovery coke oven battery, sinter process, electric arc furnace (EAF), argon-oxygen decarburization vessel, or direct reduction furnace.

However, because iron and steel facilities must already collect and report all of the data needed to comply with the federal requirements, the ARB adoption of the more comprehensive U.S. EPA requirements should not impose an additional burden on California facilities.

Under this proposal, California iron and steel production facilities would calculate GHG process emissions as specified in Subpart Q of the U.S. EPA MRR (USEPA MRR 2009-2010), unless already captured through use of a CEMS under Tier 4 of the stationary combustion requirements. Operators would comply with each of the calculation methods and reporting requirements identified in references to the U.S. EPA regulation in sections 95115 and 95120 of the proposed revised regulation, including annual production quantity, fuel use, fuel characteristics, and other data.

To fully support ARB programs, some additional modifications to the U.S. EPA MRR requirements were necessary. The primary differences are related to specific data accuracy requirements, the reporting of *de minimis* emissions, and what to do if required fuel use or other data are missing. These changes or limitations are discussed elsewhere in this report. We also propose to collect some specified product output data to support benchmarking activities.

L. Suppliers of Transportation Fuels

1. Background

Transportation fuel combustion generated about 150 million metric tons of CO_2e emissions in 2008 (CA BOE 2010a, CA BOE 2010b). Staff has proposed the inclusion of transportation fuels in mandatory GHG reporting due to their very sizable contribution to the statewide GHG inventory (approximately 36 percent of the total) (ARB GHG Inventory 2010), their importance as a contributor to emissions worldwide, and their inclusion in the U.S. EPA's final rule on mandatory GHG reporting (USEPA MRR 2009-2010). The current ARB rule does not require the reporting of these emissions (ARB MRR 2007).

In an attempt to minimize the duplication of reporting effort, staff began in early 2010 to review the feasibility of aligning the needed ARB reporting requirements for the transportation fuels sector with the U.S. EPA MRR requirements for suppliers of petroleum products. Staff reached out to potential stakeholders in the fuels industry to determine whether harmonization was feasible and practicable, and if so, what changes to the U.S. EPA MRR may be needed to support the reporting needed for a cap-and-trade program. To date the WCI has not proposed Essential Requirements for transportation fuels reporting, due to expected variations in available points of regulation and the WCI program design's postponement until 2015 of including these fuels in cap-and trade. ARB is proposing to begin transportation fuels reporting beginning in 2012, so that any reporting issues can be resolved well ahead of including this significant new source category in a cap-and-trade program.

Staff presented preliminary regulatory concepts during the March 23, 2010 public workshop, and reviewed public comments submitted at the workshop and thereafter. Taking into consideration this input staff prepared a final regulatory proposal that starts with U.S. EPA requirements, but makes several significant changes to support the cap-and-trade program in California and WCI.

2. Basis for Proposal

The staff proposal begins with the U.S. EPA requirement that suppliers of petroleum products report quantities of emissions due to downstream combustion or use of the products supplied. Our interest for reporting to support cap-and-trade is more narrow, however, and includes only emissions from transportation fuels (not all petroleum products), and only those used in California (not those exported). Due to the need to limit transportation fuel emissions to the combustion of such fuels inside the California

border, it was not possible to align directly with the U.S. EPA MRR. By harmonizing instead with the California Board of Equalization motor vehicle fuel and diesel fuel tax return process, we were able to meet the "within-California" limitation while simplifying the reporting process and reducing overall costs. GHG reports that meet the proposed ARB requirements would not meet the U.S. EPA reporting requirements, however; some entities would be required to submit different State and federal reports.

In developing the currently proposed ARB regulation, staff reviewed U.S. EPA's *Technical Support Document: Subpart MM Product Definitions and Default Emission Factors* (USEPA TSD MM 2009a), *Technical Support Document: Industry Overview of Suppliers of Petroleum Products* (USEPA TSD MM 2009b) and the *Response to Comments Document: Subpart MM — Suppliers of Petroleum Products* (USEPA Comments MRR 2009). Staff determined that the U.S. EPA MRR required modifications to: (1) only account for transportation fuels combusted within the borders of California; (2) account for emissions from biodiesel and biodiesel blends; (3) account for emissions from liquefied petroleum gas (LPG) produced at refineries; and (4) account for CH_4, N_2O, and CO_2 from biomass-derived fuels. These differences and the rationale for separate requirements are discussed below.

The first factor that made complete harmonization with the U.S. EPA MRR most difficult was the fact that we wanted to separately capture only fuels combusted within California. In the U.S. EPA MRR, the reporter is the fuel refiner. After consultation with refiners and other industry stakeholders, staff determined the refinery is not a workable point of regulation for purposes of fuel supplier reporting for cap-and-trade for most of the fuel delivered, since refineries are often not aware of the final destination of fuels they produce. After consultation with position holders and California Board of Equalization (BOE) staff we determined that BOE already requires reporting for taxation purposes of most of the needed data, including volumes of fuel imported below the terminal rack and delivered across the rack (CA BOE 2010c). We consulted with position holders and enterers (the majority of which are subsidiaries of or related to companies that own or are related to refineries), and determined that emissions reporting would not be a significant additional burden for them. Therefore, we chose position holders at the terminal rack and enterers importing below the rack as appropriate reporters for the proposed revised regulation. In order to account for all fuel combustion in California, refiners are still required to report deliveries to entities that are not licensed by the California Board of Equalization as fuel suppliers. Refiners currently report this information to BOE. ARB staff will continue to evaluate the concept of position holders relative to railroads and other specific types of fueling operations and may propose modifications to the regulations as appropriate.

We also determined that our verification needs and requirements made reporting at the refinery impractical. At refineries, verifiers would be required to verify conformance for many additional fuel measurement devices to meet the accuracy requirements of the regulation, whereas if the position holder's fuel volume across the rack is used, verifiers could trust that reported volumes are accurate because they are custody transfer points used for commercial billing and taxation purposes, and because all fuel-dispensing

devices at terminal racks are sealed by the local weights and measures authority attesting to their accuracy.

Biofuels have no specific reporting requirements in the U.S. EPA MRR. However, ARB staff has determined that transportation biofuels production and import information is important so that an accurate accounting of all transportation fuel emissions can be obtained. Biofuels production and imports are already accounted for under the ARB Low Carbon Fuel Standard (LCSF) (Title 17, *California Code of Regulations*, section 95480 *et seq.*). Staff propose to require reporting by biofuel producers and importers under the ARB MRR only if they do not report the required information under LCFS reporting.

Under the U.S. EPA MRR, refiners are required to report emissions individually from all the components of natural gas liquids (NGL). For cap-and-trade, liquefied petroleum gas (LPG) would hold a compliance obligation, so refiners would be required to report LPG emissions. As a subset of NGL, LPG would require only minor additional reporting. LPG emissions would be reported as the sum of its component emissions.

3. Reporting Requirements and Methods

The federal regulation prescribes certain criteria that, when met, allow suppliers of petroleum products to determine and report CO_2 and CO_2 from biomass-derived fuels according to a modified Tier 1 methodology (simply, Volume * Default Emission Factor). Due to the highly regulated and consistent nature of transportation fuels, the use of the modified Tier 1 methodology by suppliers of transportation fuels should provide the accuracy required for cap-and-trade. CH_4 and N_2O emissions (not required by the U.S. EPA MRR) would also be reported using a Tier 1 methodology, using the default high heat values and default emission factors allowed for stationary fuel combustion sources under Subpart C of the U.S. EPA MRR. The addition of CH_4, N_2O, and CO_2 from biomass-derived fuels is required for consistency with other sectors and the desire to capture CO_2e while tracking biogenic emissions separately.

Thus, the proposed regulation for suppliers of transportation fuels would specify calculation methods from the U.S. EPA MRR, but these methods would be used by other reporters. Under the staff proposal, all California position holders, enterers and refiners would be required to report CO_2, biomass-derived CO_2, CH_4, and N_2O from the eventual combustion of transportation fuels in California; refiners would report these emissions from LPG. Emissions would be calculated using a Tier 1 or modified Tier 1 methodology from the U.S. EPA MRR. Biofuel producers and importers would be required to report only if not already reporting under the LCFS.

Position holders, enterers, refiners, and biofuel producers would be required to report the volume (in barrels) of each component of the finished fuel by type, grade and season that is listed in U.S. EPA MRR tables M-1 and M-2, for fuel delivered across the rack, imported, supplied or produced, that will be combusted or oxidized in California. Refiners are required to report the volume of LPG, as well as the volumes of each

individual component of LPG, that will be combusted or oxidized in the state of California.

M. Suppliers of Natural Gas, Natural Gas Liquids, and Liquefied Petroleum Gas

1. Background

Natural gas combustion by core customers generated approximately 40 million metric tons of CO_2e emissions in 2008 (CGEU 2009), while liquefied petroleum gas (LPG) combustion generated approximately 7 million metric tons of CO_2e emissions in the same year (ARB GHG Inventory 2000-2008). Staff has proposed the inclusion of natural gas and LPG suppliers in mandatory reporting due to their contribution to the statewide GHG inventory (approximately 10 percent of the total), their importance as a contributor to emissions worldwide, and their inclusion in the U.S. EPA's final rule on mandatory GHG reporting (USEPA MRR 2009-2010). The current ARB rule does not require the reporting of these emissions (ARB MRR 2007).

In an attempt to minimize the duplication of reporting effort, staff began in early 2010 to review the feasibility of aligning the needed ARB reporting requirements for the suppliers of natural gas and LPG with the U.S. EPA MRR requirements for natural gas and natural gas liquid (NGL) products. Staff reached out to potential stakeholders in this industry to determine whether harmonization was feasible and practicable, and if so, what changes to the U.S. EPA MRR may be needed to support the reporting needed for a cap-and-trade program. To date the WCI has not proposed Essential Requirements for natural gas and NGL reporting, due to expected variations in available points of regulation and the program design's postponement until 2015 of including these fuels in cap-and trade. ARB is proposing to begin natural gas and LPG reporting beginning in 2012, so that any reporting issues can be resolved well ahead of including this significant new source category in a cap-and-trade program.

Staff presented preliminary regulatory concepts during the March 23, 2010 public workshop, and reviewed public comments submitted at the workshop and thereafter. Taking into consideration this input, staff prepared a final regulatory proposal that uses U.S. EPA requirements with minor changes to support the cap-and-trade program.

2. Basis for Proposal

The staff proposal begins with the U.S. EPA requirement that suppliers of natural gas and NGLs report quantities of emissions due to downstream combustion or use of the products supplied. Our interest for reporting to support cap-and-trade is more narrow, however, and only includes emissions from natural gas and certain NGLs used in California. Due to this limitation, the desire to avoid double counting of natural gas usage by large industrial users exceeding the 25,000 metric ton CO_2e threshold, the desire to capture all natural gas combusted in the state, and the desire to include LPG combusted in California, it was not possible to fully harmonize with the U.S. EPA MRR. GHG reports that meet the proposed ARB requirements would not exactly meet the U.S. EPA reporting requirements; at least minor modifications of the reports would be needed for some entities.

In developing the currently proposed ARB regulation, staff reviewed U.S. EPA's *Technical Support Document: Suppliers of Natural Gas and Natural Gas Liquids* (USEPA TSD NN 2009), and the *Response to Comments Document: Subpart NN — Suppliers of Natural Gas and Natural Gas Liquids* (USEPA Comments NN 2009). Staff determined that the proposed ARB MRR would require modifications from the U.S. EPA MRR requirements in order to (1) support a different accounting mechanism for subtracting out natural gas supplied to large industrial users above the 25,000 metric ton CO_2e threshold from the local distribution companies' (LDC) reported emissions; (2) account for emissions from LPG produced by NGL fractionators and combusted within the borders of California; (3) account for emissions from LPG imported into the state; and (4) account for CH_4, N_2O, and biomass-based CO_2 emissions. These differences in reporting requirements and their rationale for including or for not including them in the proposed revised regulation are discussed below.

The first factor that made complete harmonization with the U.S. EPA MRR difficult was the accounting methodologies employed in the federal MRR to subtract large industrial natural gas users' emissions from an LDC's reported emissions. The methodology employed by U.S. EPA could lead to double counting in instances where the large industrial user's consumption of natural gas was below 460,000 million standard cubic feet, yet its reported emissions were above 25,000 metric tons of CO_2e due to additional fuel combustion or process emissions. In order to avoid this situation, for reports under the revised ARB MRR, LDCs would report emissions without subtracting out large industrial users. ARB would then subtract the natural gas emissions from large industrial users above the 25,000 metric ton CO_2e threshold prior to calculating the compliance obligation.

Additionally, LDCs that are public utility gas corporations (PUGCs) may define the city gate as the state border for the purposes of calculating emissions from natural gas. This would result in PUGCs calculating a mass balance around their system where the total reported emissions are based on what comes in (1) at the state border; (2) from interconnects with other LDCs and intra- and interstate pipelines; (3) from in-state natural gas production; and (4) from storage, minus what goes out to interconnects with other LDCs and intra- and interstate pipelines and storage. LDCs would also have to report monthly fuel volumes and weighted average HHVs for all their wholesale customers to facilitate verification of the wholesale customers' emissions.

Complete harmonization is also prevented by the fact that NGL fractionators would only be required to calculate emissions on LPG combusted in California. The U.S. EPA MRR requires NGL fractionators to report the annual volume of odorized propane delivered to others.

Additional requirements different from those in the U.S. EPA MRR are needed due to California LPG importers and inter- and intrastate pipelines not having reporting requirements under the U.S. EPA MRR. LPG importers into the U.S. are currently required to report under the U.S. EPA MRR Subpart MM (petroleum products), and

some of these U.S. imports would also be reported under the transportation fuels section of the proposed ARB MRR. But the requirement for LPG importers into California to report the volume of LPG imported, as well as its constituents if the composition is supplied to the importer, would be added. And in order to capture all natural gas emissions, intrastate pipelines would have to report as if they were a LDC, and interstate pipelines would be required to provide customer information including monthly natural gas volumes and weighted average HHV for all of their customers in California.

3. Reporting Requirements and Methods

The federal regulation prescribes certain criteria that, when met, require suppliers of natural gas liquids to determine and report emissions of CO_2 according to either a Tier 1 (Volume * Default High Heat Value* Default Emission Factor) or a modified Tier 1 (Volume * Default Emission Factor) methodology. For LPG, we also believe that the use of a Tier 1 or modified Tier 1 methodology is appropriate. For NGL fractionators that are required to report and calculate emissions based on the actual composition of the LPG and LPG consignees (importers to California) that are required to calculate emissions based on composition when available, the use of the lower tiers does not compromise accuracy due to the use of compositional data. The default LPG factors from Table C-1 used by consignees that do not have composition data is a conservative value that is within 5% of the values of commonly sold fuels in California.

The federal regulation also prescribes certain criteria that, when met, require local distribution companies to determine and report CO_2 emissions according to methodologies which ARB is requiring to be implemented as Tier 2 (Volume * Annual Average High Heat Value * Default Emission Factor) or modified Tier 2 (Volume * Annual Average Emission Factor). ARB staff believe that due to the highly regulated nature of pipeline natural gas the use of the Tier 2, with reporter specific high heat values (HHV), or a modified Tier 2 methodology, with a reporter specific emission factor for natural gas suppliers consisting of the reporter specific HHV and the default natural gas emission factor, should provide the accuracy required for cap and trade. If the gas is outside the range of 970-1,100, the local distribution company will be required to use a Tier 3 (carbon content) methodology when calculating emissions. The addition of CH_4, N_2O, and CO_2 from biomass-derived fuels is required for consistency with other sectors and the desire to capture CO_2e while tracking biogenic emissions separately.

The proposed regulation for suppliers of natural gas, natural gas liquids and liquefied petroleum gas would use the methods of the U.S. EPA MRR. Under the staff proposal, all California local distribution companies, intrastate pipelines, interstate pipelines, NGL fractionators, and LPG importers would be required to report combustion CO_2, CH_4, N_2O, and biomass-based CO_2 emissions from the complete combustion of the fuels, using a Tier 1 or modified Tier 1 methodology from the U.S. EPA MRR.

LDCs, which consist of both public utility gas corporations and publicly-owned natural gas utilities, and intrastate pipelines would be required to report the volume of natural gas delivered to all users in California using the mass balance approach described

above. Deliveries to large industrial and wholesale customers would be subtracted before calculating the compliance obligation. PUGCs would report monthly wholesale volumes and weighted average HHV for all wholesale customers. Interstate pipelines would be required to report the fuel consumption of all their California customers, so that a complete accounting of natural gas in California can be obtained.

NGL fractionators would be required to report the volume of LPG supplied to end users in California as the sum of the individual components, and LPG consignees who import LPG into California would be required to report the volume of LPG imported and supplied to end users in California as the sum of the individual components if the composition is known, or the total volume of LPG imported if the composition is not known.

N. Suppliers of Carbon Dioxide

1. Background

There is a wide variety of applications for captured CO_2 in the economy, and it is expected that processes such as carbon capture and sequestration will grow in the future. As a result of stakeholder input, ARB staff included provisions in the current reporting regulation (ARB MRR 2007) that provided petroleum refiners and hydrogen producers the option to report transferred CO_2. Year 2008 reporting data indicates that seven California petroleum refineries reported a total of 650,000 metric tons of captured and transferred CO_2. On average this represented 3.1 percent of these facilities' total CO_2 emissions (ARB GHG Summary 2010).

2. Basis for Proposal

The U.S. EPA final rule (UEPA MRR 2009) includes a general reporting requirement for all producers of CO_2, and importers and exporters of more than 25,000 MT CO_2e from CO_2, N_2O and fluorinated GHGs, to report as suppliers of carbon dioxide. U.S. EPA also requires suppliers of carbon dioxide to report the amount of CO_2 sold for thirteen applications, such as food and beverages and enhanced oil and natural gas recovery, if known.

ARB staff evaluated the U.S. EPA requirements and concluded that reporting methods were sufficiently rigorous for a cap-and-trade program, with the exception of missing data procedures. By aligning with the wording of the U.S. EPA regulation as we develop requirements suitable for cap-and-trade, we are able to reduce duplication of effort, questions of interpretation, costs, and complexity for reporters. In most cases, GHG reports that meet the proposed ARB requirements would also meet U.S. EPA reporting requirements. The U.S. EPA MRR reporting requirements for suppliers of carbon dioxide are included in the proposed revised regulation, with two general modifications.

3. Reporting Requirements and Methods

The U.S. EPA final rule requires CO_2 suppliers to report the amount (mass) of CO_2 captured from production units, captured from production wells, and imported to and exported from the United States. Producers estimate mass from flow meter readings, and importers/exporters from bulk containers, prior to purification, processing or compressing. Reporting requirements exclude CO_2 that may be imported or exported in equipment such as fire extinguishers.

The ARB staff proposal would require these same reporters to additionally specify the mass of imports to and exports from California. ARB staff expects to use this data in the assessment of a cap-and-trade compliance obligation limited to California usage, similar to fuel suppliers.

In addition, ARB staff reviewed the missing data substitution procedures in the U.S. EPA final rule and found them to be inadequate to support market trading. The proposed revised regulation specifies separate missing data substitution procedures for reporting to ARB. Progressively more stringent requirements apply as more data are missing. The data substitution procedures, based on those in U.S. EPA's successful Acid Rain Program, are designed to provide a strong incentive for reporters to generate accurate and complete GHG accounting with as little data substitution as possible.

O. Petroleum and Natural Gas Systems

1. Background

The current ARB mandatory GHG reporting regulation requires producers of crude oil and natural gas to report all stationary combustion emissions at facilities with 25,000 metric tons or more of CO_2e (ARB MRR 2007). For 2008, California's oil and gas producers reported about 6.9 million metric tons of CO_2e from combustion (ARB GHG Summary 2010). In the Initial Statement of Reasons for the 2007 regulatory proposal, staff acknowledged some significant sources at these facilities were not covered by the proposed regulation: "...additional reporting requirements will be developed in the future for process and fugitive emissions from oil and gas exploration, production, processing, transmission and distribution" (ARB MRR ISOR 2007).

ARB began to address this shortcoming in the following year, contributing staff expertise and a portion of the funding to develop an "Oil and Gas Exploration and Production and Natural Gas Gathering and Processing Greenhouse Gas Accounting Protocol," initially drafted under the auspices of the Western Regional Air Partnership (WRAP), and ultimately published by The Climate Registry (TCR O&G 2010). In 2009, WRAP handed off the development of essential reporting requirements that could support inclusion of petroleum and natural gas combustion and process sources in a cap-and-trade program to the WCI. A Technical Working Group (TWG) with industry representatives, regulatory parties, trade and environmental groups, and U.S. EPA representation provided valuable knowledge and assistance to WRAP, WCI and TCR

throughout this period in meetings, conference calls, and through extensive written comments.

In 2009, WCI formed an Oil and Gas Subcommittee among member jurisdictions, which, with TWG input, developed a series of eight Issue Papers that were circulated for public comment in March 2010 (WCI O&G IP 2010). The Issue Papers contain draft recommendations for quantifying emissions for significant source categories in the upstream oil and gas sector, and served as the basis for WCI input to U.S. EPA as the agency developed federal reporting requirements for the sector. WCI also hosted an Oil and Gas Collaborative Meeting, held November 2009 in Santa Fe, providing the WCI Partners an opportunity to meet with interested stakeholders so that the partners could increase their understanding of the oil and gas sector and receive input directly on emissions reporting issues and emissions reduction opportunities.

2. Basis of Proposal

U.S. EPA issued a proposed rule for GHG reporting for Petroleum and Natural Gas Systems in April 2010, and intends to finalize its proposal this fall. Like the adopted reporting rule for other sectors, the U.S. EPA proposal was not written to support a cap-and-trade program. Nonetheless, as part of the ARB and broader WCI effort to harmonize with the U.S. EPA reporting regulation as much as possible, the ARB staff proposal is built around the U.S. EPA proposed Petroleum and Natural Gas reporting requirements.

Because the U.S. EPA proposal was not final by the time ARB staff had to prepare this regulatory proposal, our proposed requirements for oil and gas are different in format and in length from the requirements for other sectors. ARB's proposed requirements for oil and gas systems include complete rule language, rather than references to adopted federal rule language as in other sectors. This format may change once U.S. EPA finalizes its proposal for oil-and-gas systems, as we consider other changes following public comment on the substance of the ARB staff proposal.

In developing the proposed revised ARB MRR, staff reviewed the U.S. EPA *Technical Support Document for Fugitive Emissions Reporting from the Petroleum and Natural Gas Industry* (USEPA TSD W 2009). We also reviewed the Issue Papers discussed above (WCI O&G IP 2010), and the comments submitted by stakeholders in response to the issue papers. Staff discussed with state and provincial colleagues in the WCI Reporting Committee and the WCI Oil and Gas Subcommittee whether each proposed U.S. EPA requirement would adequately support the data needs for a cap-and-trade program. The WCI Partners commented officially on the proposed U.S. EPA reporting rule for oil and gas systems in June 2010, offering recommendations that would improve the rigor and accuracy of reporting for some source categories sufficiently to include them in the region's cap-and-trade program (WCI O&G 2010). ARB staff reviewed these recommendations, and presented preliminary thinking on inclusion of this sector in the mandatory reporting public workshop on March 23, 2010, and reviewed public comments submitted at the workshop and thereafter. Taking into consideration this

variety of input, and after careful analysis, staff prepared a final regulatory proposal. It includes several modifications to proposed U.S. EPA language where it was felt that more rigorous methodologies were required to ensure the accuracy needed to support a cap-and-trade program.

3. Reporting Requirements and Methods

U.S. EPA chose source types primarily based on the significance of their contribution to the U.S. GHG inventory (USEPA TSD W 2009). WRAP and WCI identified similar sources in their work. Based on the proposed Subpart W and WCI harmonization efforts, the proposed revised regulation would include reporting for the oil and gas production sector source types shown in Table III-2.

Table III-2. Oil and Gas Production Sector Source Types

Source Type	*CO_2*	*CH_4*	*N_2O*	*Reporting only*	*High Uncertainty*
NG pneumatic high bleed devices and pumps	x	x			
NG pneumatic low bleed devices	x	x			
Dehydrator vent stacks	x	x			
Well venting and unloading	x	x			x
Gas well venting – unconventional well completions and workovers	x	x			x
Gas well venting – conventional well completions and workovers	x	x			x
Blowdown vent stacks	x	x			
Onshore production and processing storage tanks	x	x			x
Well testing and flaring	x	x			
Associated gas venting and flaring	x	x			
Flare stacks	x	x	x		x
Centrifugal compressor wet seal degassing vents	x	x			x
Reciprocating compressor rod packing venting	x	x			
Leak detection and leaker emission factors	x	x		x	
Population count and emission factors	x	x		x	
Offshore petroleum and natural gas production	x	x	x	x	
EOR injection pump blowdown	x				
Produced water dissolved CO_2	x				
Portable equipment combustion	x	x	x		

For the sources above designated as "reporting only," the WRAP/WCI process concluded that available methodologies would not produce accurate enough data to support cap-and-trade. Additional sources were identified by U.S. EPA for which current emissions inventories are highly uncertain and may be significantly underestimated (USEPA TSD W 2009).

The sections proposed for Subarticle 5 of the staff proposal, Petroleum and Natural Gas Systems, are discussed in detail below.

Section 95150: Definition of the Source Category.
The Petroleum and Natural Gas Systems source category consists of the following industry segments. Each segment is defined in detail in the proposed regulation, consistent with U.S. EPA Subpart W.

1. Offshore petroleum and natural gas production
2. Onshore petroleum and natural gas production
3. Onshore natural gas processing plants
4. Onshore natural gas transmission compression
5. Underground natural gas storage
6. Liquefied natural gas (LNG) storage
7. LNG import and export equipment
8. Natural gas distribution

Section 95151: Reporting Entity and Threshold.
Facilities within any of the eight industry segments listed above would be required to report emissions when annual emissions equal or exceed 10,000 MT CO_2e. In the case of onshore petroleum and natural gas production, the reporting footprint under the U.S. EPA proposed Subpart W has been defined as the hydrocarbon basin as determined by the American Association of Petroleum Geologists (1991). The staff proposal incorporates the U.S. EPA approach, albeit with the 10,000 MT threshold. The reporting entity for onshore production is the operating entity listed on the state well drilling permit, or the state operating permit for wells where no drilling permit is issued by the state; section 95151(a)(1) of the proposed revised regulation adds further specification from the preamble of proposed Subpart W.

For a single facility or a reporting entity covering multiple facilities, the emissions from portable equipment would be included in determining whether emissions exceed the threshold. The proposed U.S. EPA Subpart W requires operators to include combustion emissions from portable equipment that resides at a wellhead for more than 30 days in a reporting year. This 30 day minimum residence time limitation has not been included in the proposed revised ARB MRR. This is to ensure that potentially significant portable equipment emissions in this source category are accounted for (and avoid situations where portable equipment could be shifted among facilities to avoid emissions reporting).

Section 95152: GHGs to Report.
This section specifies the source types subject to reporting for each of the industry segments in section 95150. Note that operators would also report stationary combustion emissions following the requirements of section 95115 of the proposed regulation, and the quantities of CO_2 that are captured and transferred offsite as specified in section 95123 of the proposed regulation. Those requirements are discussed elsewhere in this report.

Section 95153: Calculating GHG emissions.
The three U.S. EPA Subpart W sections 98.233(a), (b) and (c) have been modified, consolidated and are included in this proposed rule as Sections 95153(a) and (b). U.S. EPA's proposed Subpart W allows operators to use manufacturer-derived natural gas bleed rates to calculate emissions from all pneumatic high and low bleed devices and pneumatic pumps. This approach was not deemed to be of sufficient rigor for a cap-and-trade program by the WCI Oil and Gas Subcommittee. Thus, this proposed regulation contains a requirement to measure natural gas consumption for high bleed pneumatic devices and pneumatic pumps. This requirement is phased in over a two year period to provide operators with time and flexibility to meter these gas releases.

Section 95153(a), Natural gas pneumatic high bleed device and pneumatic pump venting. Operators would be required to install metering of natural gas venting on 50 percent of all high bleed devices and pneumatic pumps by January 1, 2013. Manufacturer-derived data would be used to estimate emissions for all unmetered high bleed and pneumatic pumps. By January 1, 2014, all natural gas venting by high bleed devices and pneumatic pumps would be metered. For metered devices and pumps, GHG volumetric and mass emissions (CO_2 and CH_4) would be calculated using the metered volumetric natural release and gas composition data. For unmetered devices and pumps, manufacturer-derived emissions are multiplied by device operational time to calculate annual volumetric natural gas emissions, which are then converted to GHG emissions using gas composition data.

Section 95153(b), Natural gas pneumatic low bleed device venting. The U.S. EPA proposed method has been retained in the case of all low bleed pneumatic devices. The OEM bleed rate data is multiplied by device operation time to calculate natural gas volumetric emissions. GHG emissions are then calculated using natural gas composition data.

Section 95153(c), Acid gas removal (AGR) vent stacks. The proposed U.S. EPA methodology requires operators to calculate annual CO_2 emissions based on either continuous gas analyzer data or quarterly gas analysis of gas entering and exiting an AGR unit. A mass balance equation is then used to calculate emissions.

The proposed revised ARB MRR would require increased sampling frequency (monthly) and use of a volume weighted CO_2 content in cases where a continuous gas analyzer is not installed. This requirement was deemed necessary to provide compliance grade data for cap-and-trade. A provision was added to exempt emissions reporting in cases where AGR unit vent stack emissions are captured and then re-injected into the oil/gas field.

Section 95153(d), Dehydrator vent stacks. U.S. EPA's proposed Subpart W contains two dehydrator emissions calculation methods: Method (1) for absorbent based dehydrators, and Method (2) for desiccant based dehydrators. The ARB staff proposal includes both of these methods with minor modifications. For absorbent based dehydration, operators must use the simulation software GRI-GLYCalc to calculate CH_4

and CO_2 emissions. For desiccant based dehydrators, operators must calculate emissions based on the volume and pressure of the desiccant vessel, the percent of desiccant vessel void volume, the number of fillings, and gas composition. The original U.S. EPA equation in proposed Subpart W (Eq. W-5) was modified slightly to provide a more workable formula. Instead of using the variable T (time between refilling in days) which may vary, emissions for each refilling are calculated and summed. This minor change should provide a more accurate emissions estimate without increasing the reporting burden.

Section 95153(e), Well venting for liquids unloading. The proposed U.S. EPA Subpart W rule allows operators to choose one of two emissions calculation methods. The proposed regulation requires that operators use the more rigorous Calculation Methodology 2. The operator must calculate emissions from each well venting for liquids unloading. Calculation Methodology 2 contains two terms – the first calculates emissions resulting when the well is depressurized, while the second term derives emissions during the time period that the well remains depressurized and flowing during the liquids unloading procedure. This methodology will generate more accurate and consistent data.

Section 95153(f), Gas well venting during unconventional well completions and workovers. Unconventional wells are defined as wells where hydraulic fracturing procedures have been employed to enhance gas production volumes. Currently, well "fracking" is not practiced in the State of California. This reporting methodology has been included in the proposed revised ARB MRR and is unchanged from the proposed U.S. EPA Subpart W.

Section 95153(g), Gas well venting during conventional well completions and workovers. This proposed rule adopts the proposed U.S. EPA Subpart W methodology without changes. Operators are required to calculate emissions from each gas well venting episode during conventional well completions and workovers.

Section 95153(h), Blowdown vent stacks. This proposed rule adopts the proposed U.S. EPA Subpart W methodology without changes. Operators are required to calculate the total volume of gas vented, correct this volume to standard temperature and pressure, and calculate CH_4 and CO_2 emissions based on the composition of the vented gas and number of venting events.

Section 95153(i), Onshore production and processing tanks. The proposed revised regulation would modify U.S. EPA's proposed Subpart W reporting requirements for storage tanks, to require the use of a more accurate methodology for storage tanks where the oil production rate is 10 barrels per day or greater. This change was necessary to produce more accurate data suitable for cap-and-trade. For storage tanks where the oil production rate is less than 10 barrels per day, operators may use the E&P Tanks software package to calculate CH_4 and CO_2 emissions as proposed in Subpart W. For those storage tanks where oil production is 10 barrels per day or greater, operators must annually determine the gas-oil ratio (GOR) of produced liquids.

Emissions are then calculated based on GOR and the oil production rate at the storage tank battery. Additional sampling is required if one or more producing wells are connected to or disconnected from the storage tank. This calculation methodology is based on the assumption that all the gas generated during the determination of GOR is ultimately liberated both in the storage tank and during the crude oil stabilization process.

For transmission storage tanks, the calculation methodology proposed in U.S. EPA Subpart W is not included in the proposed rule. In the Technical Support Document for this sector, U.S. EPA states, "the volume of condensate is typically low in comparison to the volumes of hydrocarbon liquids stored in the upstream segments of the industry. Hence the emissions from condensate itself in the transmission segment are insignificant." (USEPA TSD W 2009). It appears that U.S. EPA has required that operators screen transmission storage tanks to determine if emissions are occurring as a result of a stuck scrubber dump value. If emissions are detected, operators must then measure tank emissions volume and gas composition to determine GHG emissions. In comments to U.S. EPA, WCI recommended that this reporting methodology not be included. This potential emission source might better be addressed by implementation of direct emissions control regulations at the State jurisdictional level.

Section 95153(j), Well testing venting and flaring. The methodology proposed in U.S. EPA Subpart W has been included in the staff proposal with minor modifications. Operators are required to sample and measure GOR. This minor change was made to promote data consistency.

Section 95153(k), Associated gas venting and flaring. The methodology proposed in U.S. EPA Subpart W has been included in the staff proposal with minor modifications. As was the case with well testing venting and flaring, operators are required to sample and measure gas-oil ratio (GOR). This minor change was made to promote data consistency.

Section 95153(l), Flare stacks. The U.S. EPA proposed Subpart W methodology has been adopted with minor modifications. Equation W-14 has been modified to correct errors. Additionally, the value of η (flare destruction efficiency) has been modified in the case of pass-through CO_2 where η has been set to equal 0, rather than 1.

Section 95153(m), Centrifugal compressor wet seal degassing vents. The staff proposal would include this methodology from the proposed U.S. EPA Subpart W without modification.

Section 95153(n), Reciprocating compressor rod packing venting. This methodology from the proposed U.S. EPA Subpart W has been included in the ARB staff proposal without modification.

Section 95153(o), Leak detection and leaker emission factors. This methodology from the proposed U.S. EPA Subpart W has been included in the ARB staff proposal without

modification. While screening of equipment leaks provides operators with valuable qualitative information concerning which components are leaking, accurate facility-wide quantification of leaks is not practical using this methodology, and the emissions estimates would not provide compliance grade data for a cap-and-trade program.

Section 95153(p), Population count and emissions factors. This methodology from the proposed U.S. EPA Subpart W has been included in the ARB staff proposal without modification. This semi-quantitative approach will help operators focus mitigation efforts. However, a methodology using population counts and use of generic emissions factors would not provide compliance grade data for a cap-and-trade program.

Section 95153(q), Offshore petroleum and natural gas production facilities. This methodology from the proposed U.S. EPA Subpart W has been included in the ARB staff proposal without modification. California offshore facilities have not been previously been required to report GHG emission under the MMS GOAD program. Thus this reporting requirement will provide ARB with preliminary data that will help to evaluate the importance of offshore oil and gas production related emissions. This approach, however, would not provide compliance grade data for a cap-and-trade program.

Section 95153(r), Volumetric emissions. This section establishes methods for converting natural gas volumetric emission measurements made at ambient conditions to standard conditions. It is included in the staff proposal without change from the proposed U.S. EPA Subpart W language.

Section 95153(s), GHG Volumetric emissions. This section establishes methods for converting natural gas volumetric emissions to GHG volumetric emissions using the mole percent composition (CH_4 or CO_2) of the natural gas. It is included in the staff proposal without change from the proposed U.S. EPA Subpart W language.

Section 95153(t), GHG mass emissions. This section establishes methods for converting GHG volumetric emissions to GHG mass emissions using the gas density (CH_4 or CO_2). For the staff proposal, Equation W-23 of proposed U.S. EPA Subpart W was modified by removing the GWP term, as this reporting rule requires that operators report GHG emissions (CH_4 or CO_2) in terms of metric tons for each gas rather than metric tons of CO_2e.

Section 95153(u), EOR injection pump blowdown. This section establishes reporting requirements for the blowdown of pumps associated with Enhanced Oil Recovery (EOR) operations where supercritical phase CO_2 is injected into oil and gas fields to stimulate productivity. Currently, only thermal EOR activities take place in the State of California. This method is included in the revised ARB MRR to ensure that should critical phase CO_2 EOR activities begin in California that there is a method in place to quantify emissions.

Section 95153(v), Produced water dissolved CO_2. This section establishes reporting requirements for dissolved CO_2 in produced water resulting from Enhanced Oil Recovery operations where supercritical phase CO_2 is injected into oil and gas fields to stimulate productivity. Currently, only thermal EOR activities take place in the State of California. This method is included in the reporting regulation to ensure that should critical phase CO_2 EOR activities begin in California that there is a method in place to quantify emissions.

Section 95153(w), Portable equipment combustion emissions. This section requires that operators report combustion emissions from portable equipment which resides at wellheads. This equipment includes (but is not limited to) drilling rigs, dehydrators, compressors, electrical generators, steam boilers and heaters. The limitation contained in the proposed U.S. EPA Subpart W that this equipment must reside at a wellhead for more than 30 days has been eliminated. This change is designed to ensure that all combustion emissions associated with the production of oil and gas are reported.

Section 95154: Monitoring and QA/QC requirements.
This section of the staff proposal is a modification of proposed U.S. EPA Subpart W language to include requirements for additional data that must be collected as a result of the changes in methodology required by section 95123, as described above.

Section 95155: Procedures for estimating missing data.
Complete and accurate data reporting is essential to the success of a market trading program. The data substitution procedures included in this section are designed to provide a strong incentive for reporters to generate accurate and precise accounting of GHGs with as little substitute data as possible.

Section 95156: Data reporting requirements.
This section of the staff proposal is a modification of proposed U.S. EPA Subpart W language, to add several requirements for data that must be reported as a result of the changes in methodology required by section 95123, as described above.

Section 95157: Records that must be retained.
This section of the staff proposal is a modification of proposed U.S. EPA Subpart W language, to add several requirements for records that must be retained in support of the changes in methodology required by section 95123, as described above.

Section 95158: Default Emission Factor Tables.
This section reproduces tables of default emission factors referenced in the regulation text, without change from the tables in proposed U.S. EPA Subpart W.

IV. GREENHOUSE GAS VERIFICATION REQUIREMENTS

A. Background

The core verification requirements outlined in the proposed revised regulation are relatively unchanged from the requirements that exist under the current mandatory reporting regulation (ARB MRR 2007). The existing GHG reporting regulation contains third-party verification requirements for all reporting entities. Independent verification of reported GHGs is expected under international standards (ISO 2006a) and is integral to many existing GHG reporting programs, including The Climate Registry's voluntary program (TCR 2010) and the European Union Emissions Trading Scheme (EU ETS 2007). The Western Climate Initiative (WCI) also requires all participating jurisdictions to adopt regulations that include third-party verification for a regional cap-and-trade program (WCI ERMR 2009). By their nature, calculating and reporting of GHG emissions can be a complex exercise in tracking emissions sources, applying appropriate emission factors and methods, and tracking financial records. Calculation and verification of GHG emissions requires a systematic approach. International guidance reports developed by the International Organization for Standardization (ISO) (ISO 2006a) lay out best practices that require third-party verification to address the need for consistency and a high level of confidence in calculating and reporting ton of GHG emissions.

As part of this proposed regulatory action, ARB staff is proposing to continue to use independent third-party verification, consistent with WCI regional program design and international standards. ARB staff is continuing to work with local air quality management districts and air pollution control districts (AQMD/APCDs or local districts) to better define the process that allows local districts to provide verification services. Staff expects to develop proposed regulatory language related to the process for local districts' participation in verification in 15-day changes to the currently proposed regulation. In developing the verification requirements for this proposed revised regulation, staff looked at the existing verification requirements to support mandatory GHG reporting and assessed the need for improved verification requirements to support a cap-and-trade program. Internal staff review and collaboration within WCI identified areas that could be clarified or made more stringent to allow for a more rigorous and transparent verification process.

Proposed changes to the existing verification requirements were presented at a workshop on March 23, 2010. Since the proposed clarifications and new language were minor and meant to improve the verification process, there was little to no stakeholder feedback at the time. As such, staff has included the proposed changes presented at the workshop in this proposed revised regulation.

B. Verification of Emissions Data

Even though core verification requirements in the proposed revised regulation are essentially unchanged from the existing requirements, staff is proposing some minor changes and additions. Staff review found that no significant new requirements are

needed to transition verification from supporting a reporting-only program to supporting a cap-and-trade program. One new minor addition includes an equation for how verifiers will assess emissions data reports for material misstatement. This equation is consistent with WCI requirements and is based on financial auditing practices. Experience with the existing reporting program also highlighted a need for a third alternative for verification statements. The proposed regulation includes an option for a qualified positive verification statement. This option allows the verifier to make a positive verification finding where the data in the emissions data report may be free of a material misstatement, but there may be a non-conformance that does not result in a material misstatement. In the existing regulation, any non-conformance, whether or not it resulted in a material misstatement, requires the verifier to provide an adverse verification statement to the reporter.

1. The Verification Cycle

The proposed revised regulation calls for the annual verification of all emissions data reports, except for abbreviated reports of facilities outside the cap-and-trade program (i.e. those emitting between 10,000 and 25,000 metric tons of CO_2e). (These abbreviated reports are still subject to ARB audit.) Reporting entities have the option of undergoing a full verification once during a three year cap-and-trade compliance period, with less intensive verification services during the remaining years. A full verification year requires a site visit, sampling plan, review of the data management system, and data checks. Under less intensive verification requirements, verification activities may be reduced to emissions data checks based on the sampling plan developed in the full year of verification.

In performing GHG emissions verification, there is a distinction between a verification body and a verification team. The verification body is a firm that has the liability for the verification services rendered and employs the lead verifier of the verification team and the lead verifier who acts as the independent reviewer of the verification findings. The verification team is comprised of at least one lead verifier and several other verifiers (who may work for the verification body or be subcontractors) who actually provide the verification services specified in a contract between the verification body and the reporting entity.

2. Verification Activities

There are several key elements of verification as proposed in the revised regulation. For the most part, these elements are already required under the current mandatory reporting regulation. The first element is a mandatory site visit during the full year of verification. Site inspection allows the verification team to ensure that all required emission sources and processes within the defined facility boundaries are included in the emissions estimates and that the reporting entity's emissions data report is complete as required by the regulation. It is also an opportunity for the verifier to assess the adequacy of the data management and data acquisitions systems used to collect and process data underlying GHG emission estimates. At the same time, the verification team may conduct a review of contracts and other documents to

substantiate reported data and ensure that data sampling and monitoring were conducted in conformance with the regulation.

The verification team is also required to develop a verification plan. The verification plan provides documentation of planned activities, site visits, and document reviews. This plan would be submitted by the verification body to ARB with a Notice of Verification Services, ten days prior to providing verification services to a reporting entity. The Notice of Verification Services allows ARB staff to plan in advance for any additional oversight of the verification, with particular dates of verification activities proposed in advance.

A critical element of verification is the sampling plan. This plan is used to conduct data checks on the reported emissions. Verification does not call for a duplication of all emissions calculations, but rather requires the checking of specific subsets of the reported data based on several criteria. Selection of data subsets for checking involves a review of the largest contributions to overall emissions, as well as the emissions associated with the greatest uncertainties in estimation. To this end, the sampling plan includes a ranking of source contributions to overall emissions and a ranking of sources with the greatest emissions uncertainty.

The verification team conducts a qualitative risk assessment based on the uncertainty of the data acquisition equipment, data sampling and frequency, data processing, emissions calculations, data reporting, and management policies or practices applied to the emissions data report. For example, in evaluating the uncertainty of the data acquisition equipment, a verifier may check the age of a meter or the maintenance record for the meter. For data processing, the verifier may check how the data management system records and tracks data that supports emissions estimates (i.e., is it a simple spreadsheet with hand entered data used to track inputs for emissions calculations or direct readings from a data logger?). The risk assessment qualitatively evaluates how much confidence rests with the underlying infrastructure that generates emissions estimates.

The regulation does not prescribe the number of data checks; the verification team exercises professional judgment in choosing how many data checks to perform. Ultimately, however, the verification team must be able to state with reasonable assurance that the reported emissions do not contain a material misstatement for the set of sources subject to reporting, and that all applicable regulatory methodologies and requirements have been met in the estimation and reporting of those emissions estimates. The material misstatement threshold of 5 percent on a CO_2e basis at the facility level is consistent with industry practice. Anything that results in an error greater than 5 percent is considered a material error. If an emissions data report does not contain a material misstatement, then it means any errors found during verification do not cause a greater than 5 percent error in total CO_2e emissions reported by the reporting entity.

During the course of the verification, the verification team is required to maintain an issues log of any findings that may cause a material misstatement or affect conformance with the regulation. The team must also log how those issues are resolved to the satisfaction of the team so that the verification body may then provide a positive verification statement. Any findings that result in a change of the initial data report submitted to ARB must be documented. This careful documentation allows ARB to audit the verification in detail as part of its oversight role.

3. Completing the Verification Process

Upon completion of review by the verification team, the verification body submits a positive verification statement to both the reporting entity and ARB to indicate that the verification team has found no material misstatement in the emissions data report, and that the team finds the report meets the requirements of the regulation. Alternatively, the verification body submits an adverse verification statement indicating that the team has found a material misstatement or is otherwise unable to state that the emissions data report meets the requirements of the regulation. As part of the proposed revisions to the existing regulation, the new, third option for verification teams is a qualified verification statement that indicates a verification team found no material misstatement and that there is a non-conformance that did not result in a material misstatement. When providing the verification statement, the verification body will have an opportunity to add any comments or qualifiers they deem necessary to provide a complete context for the verification. The verification body also submits a detailed verification report to the reporting entity that includes the verification plan, sampling plan, issues log and additional documentation. The detailed verification report is retained by the reporting entity, but is made available to ARB upon request. The detailed verification report may be used by ARB to review the work of the verification body or review the verification process or the submitted data.

If a verification body and reporting entity cannot agree on the verifiability of the reported emissions or the need to revise the emissions data report, the reporting entity may petition ARB for review of the verification statement. ARB could use any experts at its disposal to review questions, and both parties would be held to the subsequent ARB decision.

In the event an emissions data report receives an adverse verification statement, the Executive Officer will calculate an emissions level for the reporting entity that forms the basis for its obligation under the cap-and-trade program. The factors and methods used by the Executive Officer will be the same as those used to calculate an assigned emissions level for a reporting entity in the case they had not submitted an emissions data report or failed to get the emissions data report verified by the applicable deadlines.

4. Biomass-Derived Fuels Verification

Emissions from several types of biomass-derived fuels will not be required to hold an obligation in the cap-and-trade program. Reporting entities would be able to report

these emissions separately as biomass CO_2 and not be required to hold allowances for these emissions. For the purposes of verification, verifiers must be able to have reasonable assurance that any biomass CO_2 emissions included in an emissions data report are from eligible biomass-derived fuels and that they are actually from a verifiable source and not double counted in another program. Quite often, biomass-derived fuel is injected into a natural gas transmission line located hundreds or thousands of miles from the facility that purchased that fuel. Direct measurement at the facility would therefore not accurately detect if the facility was burning a "packet" of biomass-derived fuel injected into the transmission line many miles away. Currently, there is no certification program for tracking these types of fuels as there is in the Renewable Energy Credit program. As such, ARB verifiers will have to check and verify every entity in the chain of custody from where a biomass-derived fuel is created, sold, and then combusted by a reporting entity subject to cap-and-trade. Verifiers will have to review records for sales to ensure they are real and that no party has "sold" more biomass-derived fuel then they produced or purchased. Any biomass-derived biofuel can not also receive an offset credit in another voluntary or mandatory program and still be an eligible biomass-derived fuel for reporting as biomass CO_2 that would not be subject to an obligation in the cap-and-trade program.

In the absence of a biomass-derived certification program, this level of verification is needed to ensure the reporting of biomass CO_2 is accurate, real, and verifiable. These verification requirements could be scaled back if a certification program was developed to track biomass-derived fuel as it was produced, sold, and consumed by various parties in the chain of custody. A possible model for a certification program would be one that would issue a certificate for each unit of biomass-derived fuel and as that fuel was transferred or sold, the certificate authenticating the quality of the fuel as being a biomass-derived fuel would change hands accordingly. This system would have to centrally issue and track every certificate. This type of mechanism would be limited to one certification program to ensure there was no double accounting of the same fuel in multiple programs. The reporting entity would provide the certificates as proof of their purchase and consumption of biomass-derived fuel that is not subject to an obligation. The verifiers could take those certificates at face value of evidence of the type and amount of biomass-derived fuel consumed by the reporting entity. This certificate program could be modeled after the Renewable Energy Credit program.

C. Accreditation of Verifiers

To assure the quality of verification services, staff has proposed retaining the current rigorous accreditation requirements consistent with standards in other existing programs(EU ETS 2007, TCR 2010), as well as ISO guidance (ISO 2006c). Both firms and individuals would be subject to specific requirements that include pre-screening and training under an ARB approved curriculum. To assure stability in the verification process, a company qualified to provide verification services would need to have at least five staff members, including two lead verifiers, and carry liability insurance.

The concept of a verification body having two lead verifiers comes from existing requirements in the European Union (IETA 2005). It allows for internal independent

review of verification reports and a final internal check that all verification activities and the detailed verification report meet standards in the regulation before being submitted to ARB. The Climate Registry and WCI programs have a similar requirement (TCR 2010, WCI ERMR 2009). Moreover, this requirement already forms part of ARB's current reporting requirements (ARB MRR 2007).

1. Lead, General, and Sector Specific Verifiers

ARB currently has about 230 accredited verifiers and 45 accredited verification bodies. These firms and individuals met strict eligibility criteria under the existing regulation, took ARB verifier training, and successfully passed an examination at the end of the training. The total of 230 includes both lead verifiers and general verifiers. These firms and individuals would be able to continue to provide verification services under the proposed regulation once the existing accredited verifiers have attended an ARB training workshop to learn the new reporting requirements under the proposed regulation.

ARB will retain the strict eligibility criteria and training requirements in the existing regulation as the mechanism for new individuals to become verifiers and provide verification services to reporting entities in California.

In addition to general verifiers, ARB recognizes the need for sector specific verifiers for several types of reporting entities, including refineries, transactions reporters, cement, and other manufacturing. These sectors often have complex process emissions, rigorous fuel test requirements, contractual arrangements, and sales and purchase complexities that require verifiers to have special knowledge. ARB currently offers sector specific training in addition to general verification and lead verifier training and this training would be expanded to include new sectors added by the proposed revisions. All lead verifiers and general verifiers may take the additional sector specific training. Based on experience in existing programs, these various requirements aim to ensure quality and consistency in the conduct of verification activities.

2. Accreditation to Support Cap-and-Trade Offset Project Data Report Verification

ARB is also proposing to accredit verifiers to support its compliance offset program. Most of the accreditation requirements for these individuals are the same as those for emissions data report verifiers. However, due to the complexity and variability between different project types, ARB will also require additional project specific experience and training for offset project specific verifiers. All other regulatory requirements for verifiers of offset project data reports are included in the proposed cap-and-trade regulation.

D. Conflict of Interest

ARB's conflict of interest requirements address several types of biases that may occur when a third-party verifier is reviewing an emissions data report. Biases can occur if either a reporting entity or verifier offers inducements when procuring verification services, if there is a financial interest on the part of a member of the verification body in

the reporting facility, and because of close relationships between verification bodies and reporting entities that could lead a verification body or verifier to be sympathetic to the interests of the reporting entity. Biases can also occur if a verification body or verifier has provided services that are closely related to the greenhouse gas verification services or those services actually helped in the development of the emissions data report. In this later case, familiarity with a reporting entity's facility could lead the verifier to approach the GHG verification work with a predisposition of the outcome and not truly evaluate the emissions data report with an objective and independent eye.

On a more basic level, when the verification body and reporting entity enter into a contract, they agree on a monetary payment for services rendered. As with any business relationship, there must be provisions to protect against conflict of interest. That safeguard is even more important when the verification services rendered put value on the reported emissions. Not only is the verifier reviewing the amount of emissions reported, but they are also reviewing the reporting entity's conformance with the requirements of the regulation. The proposed revised regulation contains clarifications and criteria additional to those in the existing mandatory reporting regulation for the potential for conflict of interest assessment between verification bodies and reporting entities.

ARB wants to provide highly accurate GHG data to the public and to support the cap-and-trade program. This requires the verification process to be independent and free of any external bias creeping into the process of reviewing the reported emissions. The conflict of interest requirements are drawn from existing concepts in financial auditing and environmental programs (CEC 2002). The conflict of interest policy in the regulation provides guidance and criteria as to what types of relationships and practices are unacceptable between a verification body and the reporting entity.

Prior to providing verification services to a reporting entity, the verification body must evaluate the level of potential conflict between itself and the reporting entity. This evaluation will be reviewed by ARB. If the potential conflict is determined to be high, then verification may not commence between that verification body and the reporting entity. If potential conflict is found to be low, then ARB will approve the verification and the process will commence. If ARB finds a medium level of risk of conflict of interest, ARB may request more information to improve its understanding of the relationship, and recommend steps to mitigate any conflict before finding the risk is acceptable and allowing the verification process to proceed.

A basic purpose of verification is to provide an independent level of review of the reported GHG emissions data. The conflict of interest policy strictly prohibits any verification body from acting as a consultant in estimating and reporting GHG emissions to ARB and then verifying those emissions. The proposed revised regulation lists specific tasks that are in conflict with the principle of independent review. Most of these tasks are the same as in the existing regulation.

The regulatory proposal retains the requirement for reporting entities to change verifiers after six years to avoid potential conflict of interest issues from lengthy business relationships. This results in a new set of eyes to review the emissions estimates provided by the reporting entity. Staff agrees this requirement will reduce complacency that may occur given the comfort and familiarity a verification body may feel toward a reporting entity after that time period. Verifier rotation is currently part of WCI program requirements, and ARB has retained such requirements in the proposed revised regulation.

V. ENVIRONMENTAL IMPACTS OF THE REGULATION

A. Air Quality and Environmental Impacts

The California Environmental Quality Act (CEQA) and ARB policy require an analysis to determine the potential adverse environmental impacts of proposed regulations. Public Resources Code, Section 21080.5 allows public agencies with regulatory programs to prepare a plan or other written document in lieu of an environmental impact report once the Secretary for Resources has determined that the agency meets the criteria for a Certified State Regulatory Program (Title 14, California Code of Regulations (CCR), section 15250). The Secretary for Resources has certified ARB's program for the adoption of regulations (Title 14 CCR section 15251(d)). This certification allows ARB to include an environmental analysis in the Initial Statement of Reasons for the adoption of the regulations, in lieu of preparing an environmental impact report or negative declaration. In addition, ARB will respond in writing to all significant comments that pertain to potential environmental impacts raised by the public during the public review period or at the Board hearing. These responses will be contained in the Final Statement of Reasons for the regulation.

Staff evaluated the potential environmental impacts from the proposed regulation and determined that no significant adverse environmental impacts are likely to result from the proposal. Further, staff has determined that adoption of the proposed regulation will not result in any significant adverse impacts on water quality, land, or biological resources.

This determination was made because the proposed regulation requires only reporting of GHG emissions by specified facilities to ARB, and verification by third parties, and these activities produce no adverse environmental impacts. The collected data may be used by future programs to establish baseline GHG emissions, develop and track regulatory activities, and evaluate GHG emissions reductions.

B. Environmental Justice

State law defines environmental justice as the fair treatment of people of all races, cultures, and incomes with respect to the development, adoption, implementation, and enforcement of environmental laws, regulations, and policies (Senate Bill 115, Solis; Stats 1999, Ch. 690; Government Code § 65040.12(c)). The Board approved Environmental Justice Policies and Actions on December 13, 2001, to establish a framework for incorporating environmental justice into the ARB's programs consistent with the directives of State law. The policies subsequently developed apply to all communities in California, but they recognize that environmental justice issues have been raised more in the context of low income and minority communities, which sometimes experience higher exposures to some pollutants as a result of their proximity to multiple sources of air pollutants.

Actions of the ARB, local air districts, and federal air pollution control programs have made substantial progress towards improving the air quality in California. However, some communities continue to experience higher exposures than others because of the cumulative impacts of air pollution from multiple sources.

Adoption and implementation of this regulation will have no negative environmental impacts on environmental justice communities. Facilities throughout the state will be required to report their GHG emissions, with the focus on those facilities producing the highest levels of emissions. The regulation will include mandatory reporting for over 90 percent of the stationary source GHG emissions in California, including specified combustion, process, and fugitive emissions. Emissions information from these reports will be made available to the public.

VI. ECONOMIC IMPACTS OF THE REGULATION

The economic impacts analysis shown in this report was conducted to meet current legal requirements under the Administrative Procedure Act (APA). Section 11346.3 of the Government Code requires that, in proposing to adopt or amend any administrative regulation, State agencies shall assess the potential for adverse economic impact on California business enterprises and individuals. The assessment shall include a consideration of the impact of the proposed or amended regulation on the ability of California businesses to compete with businesses in other states, the impact on California jobs, and the impact on California business expansion, elimination, or creation.

In this chapter we provide the estimated costs to businesses and public agencies to comply with staff's proposed revisions to the mandatory California greenhouse gas (GHG) reporting requirements. The regulation will affect approximately 750 facilities and other reporting entities in the state (ARB GHG Summary 2010, ARB CEIDARS 2007). Given that various facilities are under common ownership, this equates to approximately 450 businesses (ARB GHG Summary 2010, ARB CEIDARS 2007). While staff has quantified economic impacts to the extent feasible, the cost estimates are necessarily based on approximations of the amount of time required to comply with the regulation, associated labor wage rates, costs of any new required equipment or analysis, and verification costs. This impacts analysis, therefore, serves to provide a general picture of the economic impacts that typical businesses subject to the proposed regulation might encounter. We recognize individual companies may experience different impacts than those projected here, depending on various factors such as complexity of operation, facility configuration, types of fuel used, and existing compliance practices. Some facilities may experience an incremental cost increase, while some may experience an incremental cost saving as the results of the proposed revised regulation.

Overall, most affected businesses are among the larger businesses in California. We do not expect these businesses to be affected adversely by the costs of the proposed GHG reporting regulation. As a result, we do not expect a noticeable change in employment, business creation, expansion, or elimination, or business competitiveness in California. For local or State agencies, the proposed rule may result in an incremental cost for some and an incremental saving for others, but statewide, local or State agencies are expected to see a net saving from the proposed rule.

A. Summary of Costs and Economic Impacts

Implementation of the mandatory proposed revised GHG reporting regulation for California has three primary costs: 1) GHG reporting costs, including monitoring, sampling, recordkeeping activities and the preparation of an annual emissions report and, for some facilities, the purchase of new equipment and monitoring devices; 2) costs for third-party verification of submitted GHG emissions data as required; and 3) costs to the State to administer the reporting program, including training, auditing, and compliance.

In developing the revisions to the GHG reporting regulation, staff has attempted to minimize costs, while complying with the specific reporting requirements of the Act, collecting cap-and-trade quality data, and coordinating with U.S. EPA and Western Climate Initiative (WCI) reporting requirements. Under the proposed regulation, affected businesses and operations include most facilities currently subject to the extant California GHG reporting regulation (ARB MRR 2007), fuel suppliers and electric power entities, several new industrial process emissions categories, new reporting by suppliers of natural gas and transportation fuels, and the reporting of emissions and transactions by electricity importers. In addition, some facilities in the affected industry sectors that emit between 10,000 to 25,000 MT of CO_2e that are not currently subject to reporting, will be required to submit an abbreviated GHG emissions data report under the revised regulation for the purpose of monitoring the integrity of the carbon cap.

The proposed revisions to the regulation will be implemented using existing ARB staffing. In addition, costs are minimized by harmonizing the proposed ARB regulations with existing U.S. EPA reporting regulations (USEPA MRR 2009-2010) and WCI proposals (WCI ERMR 2009 and WCI HER 2010). The majority of facilities subject to the proposed ARB rule are also subject to the U.S. EPA reporting rule. Because of this, the majority of costs for reporters will be incurred in meeting the baseline U.S. EPA requirements, and there will typically only be small incremental costs to meet the additional ARB requirements after the rule revision. The additional incremental cost is due to the need for greater stringency in the ARB requirements to meet the needs of a GHG emissions cap-and-trade program and to provide consistency with the WCI requirements.

A summary of state-wide incremental costs is presented in Table VI-1.

Table VI-1. Summary of State-Wide Incremental Costs (2009 $Million)

Sector	First Year	On-going Year	Total Cost over 10 Years [5]
Privately Owned Utilities [1]	-0.2	-0.2	-2
Manufacturing	2.0	1.4	12
Fuel Suppliers [2]	1.8	1.1	9
Local Government Entities [3]	-0.2	-0.3	-2
State Government Entities [4]	<0.01	-0.01	-0.06
TOTAL	3	2	18

Table Notes:
1. Privately owned utilities include electricity deliverers, electricity generating and cogeneration facilities.
2. Fuel suppliers of petroleum products, biofuels, natural gas, and natural gas liquids.
3. Local government entities affected by the rule include publicly owned utilities, electricity generating and cogeneration facilities, and some general combustion sources at hospitals, prisons, and universities.
4. State government entities affected by the rule include state hospitals, prisons, and universities that operate cogeneration unit and other general combustion sources.
5. A 5% discount rate is applied to the 10-year costs.

For all reporting entities state-wide, we estimate the total annual costs associated with meeting GHG reporting requirements incurred by all affected entities, including businesses, local, and state government, to be $3 million (range of $1 to $8 million) during the first year. The on-going costs for the subsequent years are anticipated to be $2 million (range of $1 to $5 million) annually statewide. The first year costs are higher due to the possible need for training and planning, other start-up costs, and more intensive verification costs to meet the regulatory requirements. The staff anticipates that except for the oil and gas sector, most of the existing reporting entities will already have the necessary equipment and sampling systems in place to support GHG reporting for U.S. EPA and the existing California requirements, and it is not likely that they will need to purchase new equipment to comply with the revised regulation. We anticipate costs to diminish over time as facilities incorporate GHG reporting into their normal business practices. The ranges of the estimated costs are wide because of the substantial variability in potential reporting and verification costs among facilities subject to the regulation.

GHG reporting as specified is mandatory for any facility or entity that meets the regulation's applicability requirements. Therefore, some public agencies are subject to reporting, such as certain county or city owned sewage treatment works or landfills, local municipal utility districts or electric retail providers, some State universities, and other State facilities that emit more than 10,000 metric tons of CO_2e from stationary combustion sources or have electricity generation or cogeneration activities. The Department of Water Resources is also expected to have a reporting requirement related to imported power. Most of these facilities are already reporting to ARB under the existing rule, and are expected to see an incremental saving due to significant reduction in reporting requirements in the proposed rule revision. Staff estimates that local agencies will see an overall net saving in the range of $2 million (range of $1 to $3 million) statewide, and state agencies will see an overall net saving of $50,000 (range of $30,000 to $60,000), as a result of the proposed rule revision.

Most businesses affected by the proposed regulation are the larger businesses in California, typically with millions of dollars in annual revenue. The cost of this proposed regulation is not expected to have a significant material impact on these businesses. As a result, we do not expect a noticeable change in employment, business creation, elimination or expansion, or business competitiveness in California due the reporting requirements.

No job or business losses are anticipated in California due to the reporting regulation. Most of the job creation associated with GHG reporting was gained following implementation of the original rule. As part of this revision we are expecting a small additional increase in California employment for technical consultants who will assist facilities in meeting the revised regulatory requirements. These consultants will act as either technical assistance providers to assist in preparing emissions reports, or as verifiers, who will verify submitted emissions data for completeness and quality. Additional jobs may also become available at laboratories or facilities conducting fuel testing, or in the manufacture and installation of monitoring equipment, but these are

difficult to quantify. At full implementation of the revised regulation, we estimate that approximately 10 to 20 new verifier jobs and no new businesses would be created within California.

All the cost estimates provided in this chapter are relative to the year 2009 (current value of the costs), and all costs are given in 2009 dollars. The information, assumptions and methodologies used to determine compliance costs are summarized in Section C of this chapter.

B. Legal Requirements for Fiscal Analysis

Section 11346.3 of the Government Code requires that, in proposing to adopt or amend any administrative regulation, State agencies must assess the potential for adverse economic impacts on California business enterprises and individuals, including the ability of California businesses to compete with businesses in other states. The assessment must also include the potential impact of the regulation on California jobs, business expansion, elimination or creation, and the ability of California business to compete with businesses in other states.

Also, State agencies are required to estimate the costs or savings to any State or local agency and school district in accordance with instructions adopted by the Department of Finance. The estimate shall include any non-discretionary cost or savings to local agencies, and the cost or savings in federal funding to the State.

Health and Safety Code section 57005 requires ARB to perform an economic impact analysis of submitted alternatives to the proposed regulation before adopting any major regulation. A major regulation is defined as a regulation that will have a potential cost to California business enterprises in an amount exceeding ten million dollars in any single year. We have determined that the propose regulation is not a major regulation.

The following is a description of the methodology used to estimate costs, as well as ARB staff's analysis of the economic impact on California businesses and State and local agencies.

C. Analysis of Estimated Costs for Compliance

As a part of developing the GHG reporting regulation, we estimated the costs of compliance for facilities subject to the regulation. Briefly, the methodology for estimating costs for facilities and entities included:

- Establishing the baseline for the cost estimation;
- Categorizing affected reporting entities, which include those currently subject to reporting, those newly subject to reporting under the proposed revisions, and those that are no longer subject to reporting under this proposal;
- Identifying the new tasks that each facility type will need to perform to comply with the revised regulation, as well as the existing tasks that each facility type will

no longer need to perform;
- Evaluating the incremental costs associated with the changes in tasks that are expected to be performed by the reporting entities in monitoring and sampling fuel, preparing emissions reports, updating compliance and monitoring plans, developing GHG emission estimates, and providing staff to prepare and submit the emissions reports. The labor costs are calculated by multiplying the estimated time requirements for performing each task by a range of wage rates from the U.S. Bureau of Labor Statistics (BLS 2009);
- Estimating costs for new measurement or monitoring equipment and systems, if any, directly needed to comply with the proposed reporting requirements;
- Estimating the incremental costs for reporting facilities to contract with third-party verifiers to confirm that the facilities performed their emission estimates in compliance with the GHG reporting regulation;
- Applying the appropriate costs to each facility type to develop overall cost ranges for program implementation;
- Identifying the affected entities operated by local or state government entities and applying the appropriate costs per facility to estimate costs to local and state government; and
- Analyzing costs to small businesses.

The methodology for estimating incremental costs is described in the following subsections.

1. Determining Baseline and Incremental Costs

This analysis focuses on the net difference (or increment) between two cost estimates:

- baseline compliance costs for GHG reporting under extant regulations, and
- compliance costs under the proposed regulatory revisions.

The incremental costs estimated in this analysis do not represent the total costs to comply with GHG reporting regulations, but only the difference between the cost of mandatory GHG reporting with and without the proposed regulatory revisions. The net incremental cost combines both cost increases and cost savings.

Most affected entities —which include industrial facilities, electricity delivery entities, oil and gas entities by geological basins, and suppliers of fuels— will need to meet the U.S. EPA's GHG reporting requirements starting in 2011 (for the 2010 data year) (USEPA MRR 2009-2010). Compliance costs for California's existing GHG reporting rule will continue to be incurred even if the proposed revision is not adopted (ARB MRR 2007, ARB ISOR 2007). Some portions of these costs will be spent to comply with both the U.S. EPA and California requirements simultaneously, while some may be spent to meet only California requirements and some may be spent to meet only U.S. EPA requirements. The compliance costs due to both rules form the baseline costs of this analysis. If ARB adopts the proposed revisions and harmonizes its reporting requirements with those of U.S. EPA, some costs incurred to comply with California's

current rule will be eliminated, while some new costs will be added in support of California's proposed cap-and-trade program.

To address these complications with baseline costs, staff has chosen to frame the incremental costs analysis by the compliance tasks that reporting entities are expected to conduct before and after the revised rule becomes effective. The compliance tasks required right before the revised rule becomes effective— regardless of whether the tasks are performed for U.S. EPA only, for California only, or for both programs— are considered the baseline for the incremental cost analysis. Different facility types within the same sector may have different "baseline tasks" depending on the fuels used and the emissions units they have on site. In other words, the baseline and incremental changes are defined from the perspective of the reporting entities, not from the perspective of the ARB rule modifications.

Figure VI-1 illustrates the effects of the two rules in forming the complex baseline of this analysis using a facility that is subject to both the current California rule and the U.S. EPA rule as an example. The generic compliance task list is a representation of a compliance checklist that a facility operator may utilize to manage all the GHG reporting-related requirements. Prior to 2010 and before the U.S. EPA rule became effective, the compliance tasks performed by the reporting entities are entirely attributed to the current California rule. During 2010, the facility continues to report under the current California rule, but many of the existing compliance tasks also meet the data collection requirements of the U.S. EPA rule (though reporting to U.S. EPA does not start until 2011), while new tasks may be added as required by the U.S. EPA. The costs to comply with these rules become intertwined and inseparable for the purpose of establishing a baseline in assessing the costs to revise the California regulation. In 2011, the facility files GHG report with the U.S. EPA for the first time. The operator continues to submit GHG report to ARB under the current California rule, resulting in duplicate efforts in submitting much of the same information to two different agencies. If ARB adopts the revised rule that harmonizes with the U.S. EPA requirements, in 2012 the facility will be relieved from duplicating reporting efforts and will be submitting data only through the U.S. EPA reporting tool, but may report additional data beyond the U.S. EPA requirements to support California's cap-and-trade or other AB 32 mandates.

Using the generic compliance task list in Figure VI-1 as an example, the following compliance tasks become the baseline for the cost analysis: task (No. 1) in the current California rule that is retained in the revised rule, tasks (No. 3 to 6) that meet both the California and U.S. EPA requirements, and tasks (No. 7 to 9) required by U.S. EPA but not required by the current California rule. In the meantime, the task in the current California rule (No. 2) that is not retained in the revised rule becomes an incremental saving, while the new task (No. 10) that is not required by the current California rule nor the U.S. EPA rule becomes an incremental cost. The net change in costs that the facility may see is the sum of the incremental cost and incremental saving from the changes in compliance tasks.

However, not all the affected entities are subject to the current California rule, the U.S. EPA rule, and/or the revised California rule, as in the example above. The effects of the 3 rules and their respective applicability criteria form 5 different baseline scenarios. Tables VI-1a to VI-1e describe these baseline scenarios and provide examples of each. In reality, reporting entities within the same industry sector can fall into different baseline scenarios. Therefore, there is often a one-to-many relationship between industry sector and the baseline scenario. Categorization of industry sectors into more detailed facility types is further discussed in the next subsection.

Figure VI-1. Illustration of Generic Compliance Tasks Due to California and U.S. EPA Regulations in Determining the Baseline for the Cost Analysis

2009	2010	2011
Compliance Task 1	Compliance Task 1 (CA only)	Compliance Task 1 (CA only)
Compliance Task 2	Compliance Task 2 (CA only)	Compliance Task 2 (CA only)
Compliance Task 3	Compliance Task 3 (both CA & U.S. EPA)	Compliance Task 3 (both CA & U.S. EPA)
Compliance Task 4	Compliance Task 4 (both CA & U.S. EPA)	Compliance Task 4 (both CA & U.S. EPA)
Compliance Task 5	Compliance Task 5 (both CA & U.S. EPA)	Compliance Task 5 (both CA & U.S. EPA)
Compliance Task 6	Compliance Task 6 (both CA & U.S. EPA)	Compliance Task 6 (both CA & U.S. EPA)
	Compliance Task 7 (U.S. EPA only)	Compliance Task 7 (U.S. EPA only)
	Compliance Task 8 (U.S. EPA only)	Compliance Task 8 (U.S. EPA only)
		Compliance Task 9: Reporting to U.S. EPA (U.S. EPA only)

Incremental Cost	2012
Baseline	Compliance Task 1 (CA only)... ***retain the same requirement***
Incremental saving	~~Compliance Task 2 (CA only)~~ ...***no longer required***
Baseline	Compliance Task 3 (required by U.S. EPA, data used by CA)
Baseline	Compliance Task 4 (required by U.S. EPA, data used by CA)
Baseline	Compliance Task 5 (required by U.S. EPA, data used by CA)
Baseline	Compliance Task 6 (required by U.S. EPA, data used by CA)
Baseline	Compliance Task 7 (required by U.S. EPA, data used by CA)
Baseline	Compliance Task 8 (required by U.S. EPA, data used by CA)
Baseline	Compliance Task 9 (required by U.S. EPA, data used by CA)
Incremental cost	Compliance Task 10 (CA only) ...***new requirement for supporting cap & trade***

Table VI-2a. Regulated entity subject to both the current California rule and U.S. EPA rule (Examples: refineries, cement plants, some industrial facilities with combustion sources, and some power plants and cogeneration plants)

	2009	2010	2011	2012 and beyond
Subjected Rules	Report under the current CA rule.	Report under the current CA rule. Start collecting data for reporting to U.S. EPA for the first time in 2011.	Report under the current CA rule, and report to U.S. EPA for the first time.	Proposed revised rule harmonizes with U.S. EPA rule, with additional requirements to support cap-and-trade.
Cost Attribution	Costs are entirely attributed to the current CA rule.	Some resources spent on sampling and collecting data will be used to comply with both the CA and U.S EPA rules, some may be spent for CA only while some for U.S. EPA only. The resources spent on reporting are attributed to CA only.	Some resources spent on sampling and collecting data will be used to comply with both the CA and U.S EPA rules, some may be spent for CA only while some for U.S. EPA only. Reporting to CA and U.S. EPA separately.	Regulated entities comply with the U.S. EPA rule, but may incur marginal incremental costs to comply with the additional requirements in the revised CA rule or see some cost savings from reduced CA-only requirements. Report to U.S. EPA directly (along with the additional data required by CA only) and no longer need to report to CA separately.

Table VI-2b. Regulated entity subject to the U.S. EPA rule but not the current California rule (Examples: certain facilities in the glass production, lime production, nitric acid production, and fuel supplier sectors)

	2009	2010	2011	2012 and beyond
Subjected Rules	None	Start collecting data for reporting to U.S. EPA for the first time in 2011.	Report to U.S. EPA for the first time.	In addition to complying with the U.S. EPA rule, they are subject to the CA rule for the first time.
Cost Attribution	None	Resources spent on sampling and collecting data are attributed entirely to U.S. EPA.	Resources spent on sampling, collecting data, and reporting are attributed entirely to U.S. EPA.	Regulated entities comply with the U.S. EPA rule, but may incur marginal costs to comply with the additional requirements in the revised CA rule. Report to U.S. EPA directly (along with the additional data required by CA only).

Table VI-2c. Regulated entity subject to both the current and revised California rules, but not the U.S. EPA rule (Examples: electricity deliverers, geothermal power plants, and electricity generating and cogeneration facilities with <25,000 $MTCO_2e$ emissions)

	2009	2010	2011	2012 and beyond
Subjected Rules	Report under the current CA rule.	Report under the current CA rule.	Report under the current CA rule.	The proposed revised rule becomes effective
Cost Attribution	Costs are entirely attributed to the current CA rule.	Costs are entirely attributed to the current CA rule.	Costs are entirely attributed to the current CA rule.	Regulated entities may incur some incremental costs to comply with the additional requirements in the revised CA rule or see a net savings from the reduced requirements from the current rule.

Table VI-2d. Regulated entity not subject to any reporting rule currently, but will be subject to the revised California rule (Examples: certain fuel suppliers; any industrial facilities with combustion emissions greater than 10,000 $MTCO_2e$ but less than 25,000 $MTCO_2e$ that are not currently reporting)

	2009	2010	2011	2012 and beyond
Subjected Rules	None	None	None	The proposed revised rule becomes effective
Cost Attribution	None	None	None	All new GHG reporting costs are attributed to the revised CA rule.

Table VI-2e. Regulated entity subject to the current California rule, but will no longer be subject to reporting under the revised rule (Examples: electricity generating and cogeneration facilities with >1MW capacity and between 2,500 and 10,000 $MTCO_2e$ of emissions)

	2009	2010	2011	2012 and beyond
Subjected Rules	Report under the current CA rule.	Report under the current CA rule.	Report under the current CA rule.	The proposed revised rule becomes effective. No longer need to report.
Cost Attribution	Costs are entirely attributed to the current CA rule.	Costs are entirely attributed to the current CA rule.	Costs are entirely attributed to the current CA rule.	Cost saving.

2. Costs Categorization of Affected Facilities

To estimate incremental costs incurred by reporting entities to comply with the proposed rule revisions, staff categorized the affected entities by applicable changes in reporting requirements resulting from the revisions. To the extent possible, staff categorized the reporting entities into facility types that will be affected by the revised rule in different ways, as some existing tasks are no longer required after the rule harmonization and new compliance tasks become effective under the revised rule. The U.S. EPA rule requirements implemented are by emission units (i.e., distinct emissions sources or equipment at facilities). However, the existing California rule takes a primary industry "sector" approach. Therefore a facility may be subject to reporting under multiple subparts of the U.S. EPA rule, which in come cases prevents the precise alignment of ARB and U.S. EPA facility categories before and after the rule revision.

Due to the intertwining requirements of the existing California rule and the U.S. EPA rule that form the baseline of this analysis, different types of facilities within the same industry sector will see different incremental impacts from the proposed rule revision. In most cases, one industry sector can often be categorized into several facility types, with each expecting to see different incremental impacts. For example, the electricity generating sector is further categorized into 7 facility types: Part 75 facilities, non-Part-75 facilities that emit >25,000 MT of CO_2e, facilities that emit 10,000 to 25,000 MT of CO_2e that use natural gas as primary fuel, facilities that emit 10,000 to 25,000 MT of CO_2e combusting fuels that may require fuel sampling, facilities that emit less than 10,000 MT of CO_2e that are currently reporting to ARB, geothermal facilities, and facilities with hydrogen fuel cell generating units. In contrast, the cement production sector does not need to be categorized into more detailed facility types because staff anticipates the incremental impacts are relatively uniform within this sector.

Staff categorized the affected facilities into 48 facility types in 16 industry sectors. The facility categorizations are listed in Table VI-3 along with the GHG reporting rules that they are subject to. For each facility category, staff summarized the changes in compliance tasks before and after the effective date of the proposed revised rule and estimated the costs of compliance for these tasks. The cost to perform a new task represents an incremental cost increase, while the cost to perform a current task that is no longer required under the revised rule represent an incremental cost saving (or a negative cost number). The following subsections describe the methodology that staff employed for the cost estimation.

Table VI-3. Reporting Entity Categorization

Industry Sector	Reporting Entity Category	Subject to		
		Current CA Rule	U.S. EPA Rule	Proposed CA Rule
Cement Production		✓	✓	✓
Electricity Deliverers	In-state retail provider with no electricity import from out-of-state	✓		✓
	In-state retail provider with electricity import	✓		✓
	Multi-jurisdictional retail providers	✓		✓
	Electricity marketer	✓		✓
Electricity Generation	Part-75 facilities	✓	✓	✓
	non-Part-75, >25,000 MT of CO_2e	✓	✓	✓
	10,000 to 25,000 MT of CO_2e, primarily natural gas fired	✓		✓
	10,000 to 25,000 MT of CO_2e, combusting non-natural gas fuels	✓		✓
	>1MW but <10,000 MT of CO_2e	✓		
	Geothermal facilities	✓		✓
	Facilities with hydrogen fuel cell EGU			✓
Cogeneration (stand-alone facility)[3]	≥25,000 MT of CO_2e	✓	✓	✓
	10,000 to 25,000 MT of CO_2e	✓		✓
	<10,000 MT of CO_2e and >1MW	✓		
Petroleum Refineries	Large refineries currently reporting to ARB as refineries	✓	✓	✓
	Small refineries currently reporting to ARB as general stationary combustion facilities	Note 1	✓	✓
Hydrogen Production	Stand-alone merchant plants	✓	✓	✓
	Stand-alone hydrogen plant with cogen	✓	✓	✓
Stationary Combustion	≥ 25,000 MT of CO_2e, can obtain fuel characteristic data from fuel suppliers	✓	✓	✓
	≥ 25,000 MT of CO_2e, need to conduct fuel testing	✓	✓	✓
	<25,000 MT of CO_2e			✓
Glass Production	>25,000 MT of CO_2e		✓	✓
	10,000 to 25,000 MT of CO_2e			✓
Lime Manufacturing			✓	✓
Nitric Acid Production			✓	✓
Pulp & Paper Mfg	>25,000 MT of CO_2e	Note 1	✓	✓
	10,000 to 25,000 MT of CO_2e			✓
Iron & Steel Production			✓	✓
Oil & Natural Gas System	Oil and gas exploration	Note 1	✓	✓
	Pipeline transportation of natural gas		✓	✓
	Natural gas distribution		✓	✓
Suppliers of Petroleum Products and Biofuels	Position holders- currently reporting as refineries	Note 2		✓
	Position holders- new to reporting			✓
	Enterers			✓
	Refineries producing LPG	Note 2	✓	✓
	Biofuel producers			✓

Suppliers of Natural Gas and NGL	Public utility gas corporation		✓	✓
	Publicly-owned natural gas utilities		✓	✓
	Interstate pipelines covered by Subpart NN		✓	✓
	Intrastate pipelines not covered by Subpart NN			✓
	NGL fractionators		✓	✓
	LPG consignees			✓
Suppliers of CO_2			✓	✓

Table Notes:
1. Some of the facilities in this category may be currently reporting to ARB as general stationary combustion facilities
2. Some of the facilities in this category may be currently reporting to ARB as refineries.
3. These are stand-alone cogeneration facilities that are not attached to other industrial operation.

3. Costs of Performing Compliance Tasks

A survey seeking reporting entities' inputs on costs of compliance was not conducted. Although such a survey can provide valuable data on the total costs incurred by reporting entities to comply with GHG reporting rules, it does not directly inform the incremental cost impacts of the revised regulation. A survey that provides relevant data for informing incremental costs would require a series of very extensive survey questions specific to each sector, and would be overly burdensome to potential respondents. Instead, staff utilized a method similar to an expert elicitation process to estimate the cost components, including labor costs (associated with monitoring, sampling, recording, training, and planning), fuel analysis cost, equipment cost, and verification cost, based on staff's experience in providing support to reporting entities and verification bodies. The method for estimating each cost component is described below.

Labor Costs

Since the inception of the California GHG reporting program in 2008, staff in ARB's Climate Change Reporting Section has been working closely with reporting entities in providing technical supports for emission calculations, providing training on the rule requirements and the use of the reporting tool, assisting reporters in preparing and submitting electronic GHG reports, and noting informal feedback from reporters on the time requirements of GHG reporting. Staff in ARB's Climate Change Verification and Protocols Section has been working closely with the accredited verifiers in ensuring the quality of GHG reports, observing the actual on-site practices of reporting entities (observations took place during verification site visits), and analyzing informal feedback provided by verifiers and reporters regarding the expenses of GHG reporting and verification. The staff in both sections has knowledge of the costs and efforts expended by reporting entities in complying with the GHG reporting regulation (ARB MRR 2007). Based on the knowledge acquired from this extensive experience in providing support and assistance to reporting entities, staff estimated ranges of costs and numbers of hours spent on certain compliance tasks.

Each staff in the two sections is a "sector lead" for one or several industry sectors covered by the GHG reporting rule and has developed knowledge of their sectors' compliance practices. To methodically estimate the labor costs of certain compliance tasks, the staff members are asked a series of questions that are customized according to the specific facility categories identified previously. Some example questions may include:

> *"Describe what a typical facility in your sector is doing now for GHG reporting, describe what they will be doing after the revised rule is implemented, and describe the difference in compliance tasks;"*
>
> *"Based on your experience in observing reporters' compliance practices during verification site visits, approximately how much time (in range of number of hours) is the staff at a typical refinery spending on coordinating and preparing records for verification?" or*
>
> *"Based on your experience in assisting reporters in emission calculation, approximately how much time is a typical technical staff at a cogeneration plant spending on collecting data and performing the distributed emission calculations required by the rule?"*

Following this approach, staff estimated ranges of time requirements for performing the following compliance tasks:

- Becoming familiar with rule requirements and the use of the reporting tool, preparing and implementing compliance monitoring plan for GHG reporting, and training facility staff in performing compliance tasks;
- Collecting data and calculating emissions using default emission factors;
- Collecting data and calculating emissions using fuel characteristic data (e.g. high heat value and carbon content) provided by the fuel suppliers;
- Collecting and analyzing fuel samples, keeping records of fuel analytical data, and calculating emissions at various periodic sampling frequencies;
- Monitoring proper operation of fuel measurement equipment and recording fuel use data;
- Measuring cogeneration system efficiencies for performing engineering calculations for distributing emissions between power production and thermal production;
- For electricity deliverers and suppliers of fuels, gathering data required for GHG reporting from their existing database system;
- For oil and gas facilities, complying with the additional monitoring and fuel testing requirements in storage tanks and acid gas removal units, as well as monitoring emissions during well unloading/cleanup;
- For each applicable sector, performing additional process emissions calculations called for by the respective sections of the proposed revised regulation;

- Entering data, performing quality assurance (QA) checks, and certifying GHG reporting submission in the reporting tool;
- Time avoided by not having to enter the same GHG reporting data into 2 different reporting tool systems for California and U.S. EPA;
- Identifying and selecting verification service providers, preparing conflict of interest application, and reviewing contracts with the verifier;
- Coordinating, preparing records for, and hosting verification site visits; and
- Following-up on verification and revising GHG report as needed.

Staff estimated the incremental time requirement of different compliance tasks that are expected for the 48 facility types in 16 sectors. Most facility types are expected to see only 1 to 4 incremental tasks listed above as the result of the rule change, although they may be already performing most of these tasks under the current California and U.S. EPA regulations.

For general compliance tasks that may be applicable to many sectors of various levels of complexity, such as fuel monitoring and verification, staff estimated different levels of time required to better represent the efforts needed for a facility. For example, a complex facility such as a refinery is likely to spend significantly more time preparing for and hosting a verification site visit than a simple facility such as an electricity generation plant with only one natural gas-fired engine. In this case, staff developed time requirement estimates for a simple, moderate, and complex facility for preparing and hosting the verification site visit, and applied them to each facility type appropriately. With these time requirement modules developed, the total labor costs for performing each compliance task are estimated by multiplying the estimated time requirement of the task by a range of wage rates (in $/hour) for the type of facility staff that typically performs the task.

Staff assigned each individual task to a class of facility staff that typically performs that task. Facility staff classes include administrative staff, technical staff, managerial staff, and lawyers. The technical staff class is further divided into two classes based on typical salary ranges: technical staff 1 may include junior engineers, scientists, senior operators, and senior technicians; and technical staff 2 may include mid to senior level engineers or compliance specialists.

The U.S. Bureau of Labor Statistics (BLS) 2009 Occupational Employment and Wage Estimates data (BLS 2009) for the state of California are used to construct ranges of wage rates. The wage data for several similar occupations that are likely to perform the compliance tasks are combined together to form the 5 facility staff classes in the analysis. For example, the technical staff 2 wage rate range is a composite of wage rates of chemical, civil, environmental, industrial, mechanical, and health and safety engineering occupations. The minimum 25th percentile, the maximum 75th percentile, and the average of the median wage rate values in the BLS data set are used as low, high, and mid estimates, respectively.

To account for the total labor costs incurred by the reporting entities, which may include employee benefits and overhead costs, staff applied the same adjustment factors that U.S. EPA used in estimating the economic impacts of the federal GHG reporting program (USEPA 2009a). These adjustment factors are a "benefit loading factor" of 0.5 and an "overhead loading factor" of 0.17. In other words, the ranges of wage rates extracted from BLS data are scaled up by a factor of 1.67 to obtain the final "loaded wage rate" numbers for the labor cost analysis. The resulting loaded wage rates for the 5 facility staff classes in 2009 dollars are summarized in Table VI-4.

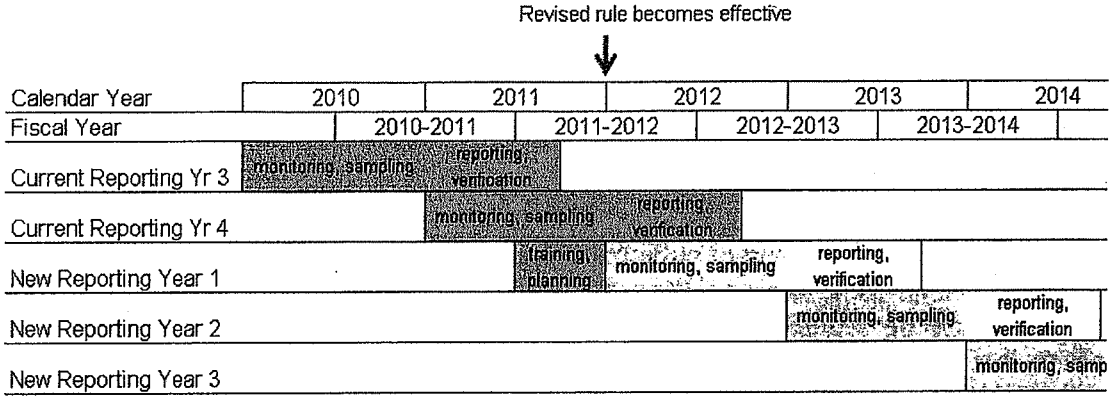
Table VI-4. Wage Rates Used to Estimate Labor Costs

Facility Staff Class	Loaded Wage Rate (2009$/ hour)		
	low	Mid	high
Administrative	21.41	23.54	27.25
Technical 1	34.52	47.85	62.91
Technical 2	51.15	68.81	79.63
Managerial	72.59	87.32	108.92
Lawyer	79.07	111.72	144.37

To estimate the labor costs of each facility type that will be affected by the revised rule in different ways, the labor costs of the applicable compliance task are summed to obtain the total incremental labor costs of the revised GHG reporting rule. For the current tasks that will no long be required under the revised rule, the costs for performing those tasks are subtracted (or represented by a negative value as cost saving).

To keep cost accounting on a yearly basis, staff summed the costs by yearly reporting cycle, which does not necessary coincide with a calendar year. For example, the labor costs for recording fuel use and collecting/analyzing fuel samples are expended during calendar year 1, but the labor costs for performing emission calculations and reporting those emissions released in calendar year 1 typically occur at the beginning of calendar year 2, and the costs for preparing and hosting verification typically occur in the middle of calendar year 2. (At the same time, while reporting and verification activities are underway during calendar year 2, the reporting entities are recording fuel use and collecting/analyzing fuel samples for the second reporting year.) The costs of these tasks together are considered the costs for "reporting year 1," although the costs are spread into 2 calendar years. Figure VI-2 graphically illustrates the overlap of "reporting year," "calendar year," and "fiscal year."

Figure VI-2. Reporting Year, Calendar Year, and Fiscal Year



Equipment Costs

Staff anticipates that most affected facilities, except for those in the oil and gas sector, will already have the necessary equipment in place for GHG reporting, either due to the existing California reporting rule or the U.S. EPA rule, by the time that the proposed rule revision becomes effective. Most of the incremental costs will be labor costs associated with the new compliance tasks, and most facilities should be able to meet the new requirements in the proposed rule without purchasing additional equipment. Some facilities may choose to install backup monitoring equipment to ensure data quality beyond the rule requirements, but staff does not expect that this will be common and did not include these costs in the analysis.

The proposed rule requires oil and gas system facilities to meter natural gas flow to pneumatic actuated pumps and high bleed devices, and to use a portable choke valve metering device to monitor well emissions during well unloading. Some facilities will need to purchase this equipment to comply with the revised rule. Staff estimated that a gas flow meter costs approximately $1,000-$2,000 to purchase and install, and a portable choke valve metering device costs approximately $500-$600. Because these new purchases are not significant capital investments, and oil and gas system facilities are likely able to purchase the equipment without financing or loan, staff chose not to annualize these capital costs over multiple years and assumed that these costs are incurred during the first year of the revised regulation implementation.

Fuel Analysis Costs

In California, most facilities use natural gas as their primary fuel. They will be able to use either the default emission factor or the high heat value provided by the fuel suppliers to calculate emissions. Suppliers of coal and petroleum coke typically provide carbon content data to their customers in billing records, giving facilities that combust these fuels the option to calculate emissions without fuel sampling and analysis. The

proposed revised rule also allows facilities that combust standard liquid fuels (e.g. gasoline, diesel, fuel oils, LPG) and biofuels except digester gas (e.g. wood, agricultural byproducts, biodiesel) to calculate emissions using default emission factors. For other fuels, depending on the equipment size and amount of fuel used, some facilities would be required to collect and analyze periodic fuel samples to determine fuel characteristics for emissions calculation purposes.

In addition to estimating the time requirements for a typical facility to collect fuel samples and analyze them in-house, staff also contacted a few commercial laboratories in the state to obtain cost quotes of fuel analysis. In general, a simple fuel analysis of moisture content, carbon content or higher heating value may cost $70 to $120 if analyzed by commercial laboratories, or $35 to $190 if analyzed in-house (actual costs may depend on the capacity and efficiency of the in-house staff; it is assumed that facilities that are already sampling fuels on a frequent, regular basis for either the existing GHG reporting requirements or other operational purposes will likely take less time per fuel sample). Staff also obtained a cost quote of $600 to $800 from a commercial laboratory for gas content analysis required for oil and gas system facilities. Staff applied these costs to the incremental fuel sampling tasks expected under the revised regulation.

Verification Costs

In working closely with the accredited verifiers and collecting feedback informally provided by verifiers and reporters, staff has compiled estimated ranges of verification service fees that reporting entities spent to comply with the existing verification requirements. The year 2010 is the first year that verification is required under the current GHG reporting rule, and verifiers and reporters alike are learning the process for the first time and spending more time on working out details and developing expertise. After the issues encountered have been worked out and reporters have updated their monitoring plans or emissions calculations during the first mandatory verification cycle, staff expects that the verification service fee in the on-going years will be lower than in this first year.

Using the ranges of verification service fees in the first year and the estimated time requirements for verifiers to perform specific verification-related tasks, staff estimated the likely ranges of verification service fees in the future years, which could either be an intensive verification or less-intensive verification (see Section IV of this report for a discussion of verification requirements). Most facilities will need to go through an intensive verification at least once in every 3 years, and it is assumed that for the other 2 years, approximately half of the facilities will have no major issues to warrant an intensive verification and a less-intensive verification will suffice.[7] Staff estimated the ranges of verification service fees and the time requirements for facility staff to perform various verification-related tasks during both intensive and less-intensive verifications,

[7] A site visit and new contract establishment is not required for less-intensive verification, which reduces labor costs associated with verification by approximately 40%-50% when compared to a year that intensive verification is needed.

and applied these costs to each facility types for the first year and for on-going years. The annual verification cost in the on-going years is a composite of the cost expected for a typical intensive verification year and a typical less-intensive verification year, where each is weighted equally at 50%.

Oil and Gas Sector

The oil and gas system sector is handled differently from the other sectors affected by the proposed rule because the U.S. EPA has not adopted 40 CFR Subpart W—*Mandatory Reporting of Greenhouse Gases: Petroleum and Natural Gas Systems* (USEPA 2010w) at the time of this fiscal analysis, though a draft rule has been published and the final rule will likely be adopted before this proposed regulation revision is implemented. See Section III.N of this report for a more detailed discussion of California's proposed harmonization with Subpart W and the additional requirements for this sector.

The U.S. EPA estimated the first-year costs to comply with Subpart W are approximately $24,000 per crude petroleum and natural gas extraction entity, $18,000 per pipeline transportation of natural gas entity, and $11,000 per natural gas distribution entity (USEPA 2009b). The second year costs are approximately half of the first-year costs. To support cap-and-trade, the proposed California regulation will require additional sampling, monitoring, and calculation tasks beyond those required in Subpart W. Staff estimated the incremental costs to comply with the additional requirements in the proposed rule using the methods described in this section.

Under the baseline scenario in which U.S. EPA adopts Subpart W, only the California-only incremental costs are attributed to the proposed California rule. On the other hand, under another baseline scenario in which Subpart W is not adopted by U.S. EPA and California carries forward the requirements in the proposed Subpart W as well as the additional reporting requirements specific to California reporters, the incremental costs would be approximately the costs to comply with Subpart W estimated by U.S. EPA plus the incremental costs that staff prepared in this analysis.

Moreover, under the current California GHG reporting rule, oil and gas exploration facilities are reporting using the existing "facility" definition.[8] In the proposed revised

[8] The current GHG reporting rule (ARB MRR 2007) defines "facility" as: *"Facility" means any property, plant, building, structure, stationary source, stationary equipment or grouping of stationary equipment or stationary sources located on one or more contiguous or adjacent properties, in actual physical contact or separated solely by a public roadway or other public right-of way, and under common operational control, that emits or may emit any greenhouse gas. Operators of military installations may classify such installations as more than a single facility based on distinct and independent functional groupings within contiguous military properties.* On the other hand, the U.S. EPA GHG reporting rule (USEPA MRR 2009) defines oil and gas production reporting entities by the production "basin", regardless of how "contiguous or adjacent property" boundaries are drawn using the "facility" definition. In other words, if an operator operates 4 oil & gas exploration "facilities" in a basin, the operator will be reporting them as one entity in the GHG reporting program, regardless of how each of these "facilities" may be defined by "contiguous and adjacent property."

rule, California is harmonizing with U.S. EPA's "geological basin" approach. Therefore, reporting entities in California will also report by geological basins after the implementation of the proposed rule. Staff expects that some oil and gas exploration "facilities" that are currently reporting to ARB will be combined under the "basin" approach, and some existing oil and gas "facilities" that are below the current 25,000 MT of CO_2e reporting threshold and are not currently reporting to ARB will be incorporated into the reporting entity's inventory in the future. New oil and gas entities with 10,000 to 25,000 MT of CO_2e of emissions will also come into the GHG reporting program as abbreviated reporters.

Due to these changes, it is difficult to project the number of reporting entities and their incremental costs per facility. However, staff estimates that there may be a total of 12 to 38 oil and gas exploration entities reporting under the "basin" approach, and their costs of compliance will vary significantly among the entities. Although staff does not have an accurate projection of the number of affected oil and gas exploration entities at this time, the state-wide costs for the additional monitoring, sampling, and reporting requirements for crude oil storage tanks, acid gas removal unit, and well cleanup activities can be estimated from the state-wide equipment inventory maintained by ARB's Stationary Source Division (ARB O&G Survey 2007). Unlike what was done for the other sectors, for which we first calculated the costs per entity by incremental compliance tasks, then multiplied the cost per entity by the number of projected reporting entities to obtain the state-wide costs, for this sector, staff first estimated the state-wide incremental costs to comply with the additional requirements in the proposed rule, then divided the state-wide costs by the likely range of number of reporting entities to obtain the per-entity costs (ARB O&G Survey 2007).

State and Local Government

GHG reporting as specified is mandatory for any facility or entity that meets the regulation's applicability requirements. Therefore, some public agencies are subject to reporting, such as certain county or city owned sewage treatment works or landfills, local municipal utility districts or electric retail providers, some State universities, and other State facilities that emit more than 10,000 metric tons of CO_2 from stationary combustion sources. The Department of Water Resources is also expected to have a reporting requirement related to imported power. To estimate the economic impacts on state and local government entities, the following steps were taken.

First, staff reviewed the list of currently reporting entities and identified the local government agencies that are subject to reporting, including cities, counties, public utility districts, or other public entities that maintain facilities that are subject to reporting. Staff identified 10 state government agencies and 126 local government entities that are currently in the GHG reporting program (ARB GHG Summary 2010). Staff also reviewed a separate list (ARB CEIDARS 2007) of potentially affected entities that are not currently reporting GHG emissions to ARB but may be newly subject to the proposed regulation's revised threshold. The potentially affected entities list is based on an older inventory of emission sources compiled by ARB staff using information requested and obtained from

the local air quality management districts and air quality control districts. Although it can provide a general sense of the number of potentially affected entities, it is not a precise projection of which entities may be affected. Each potentially affected entity must conduct a GHG emission inventory to determine their applicability to the revised regulation. Staff estimated that there may potentially be 11 additional state and local government entities subject to GHG reporting.

Second, staff sorted these state and local government entities into the appropriate facility categories in the electricity deliverer, electricity generation, cogeneration, and general stationary combustion sectors (see Section C.2, Costs Categorization of Affected Facilities for a description of the facility categorization). Among these public entities, 26 electricity generating or cogeneration facilities owned by local government entities are currently subject to reporting (due to the existing 1 MW and 2,500 $MTCO_2e$ threshold) but have emissions less than 10,000 MT of CO_2e and will therefore no longer need to report under the revised regulation.

Third, to estimate the costs to state and local government entities, staff multiplied the number of entities in each facility category by the expected incremental costs per facility for the respective facility category, which were calculated using the approach described in the previous subsections. Like their counterparts in the private sectors, publicly owned electricity generating and cogeneration facilities that emit less than 25,000 MT of CO_2e, as well as public electric utilities, are expected to see a cost saving from the significantly reduced reporting requirements, while the other facilities can expect to see a slight incremental cost increase for reporting.

Lastly, the estimated costs for each facility category are summed to obtain the net state-wide costs to local and state government. The results are presented in Section D.

Small Businesses

ARB does not collect small business status information from reporting entities under the current GHG reporting regulation. Staff does not know exactly which affected entities qualify as a small business, which is defined by the California Department of General Services as a business that meets all of the following qualifying criteria (DGS 2010):

1) It is independently owned and operated; and
2) The principal office is located in California; and
3) The officers of the business in the case of a corporation; officers and/or managers, or in the absence of officers and/or managers, all members in the case of a limited liability company; or the owner(s) in all other cases, are domiciled in California; and
4) It is not dominant in its field of operation(s); and
5) It is either:
(A) A business that, together with all affiliates, has 100 or fewer employees, and annual gross receipts of fourteen million dollars ($14,000,000) or less as averaged for the previous three tax years, as

adjusted by the Department pursuant to Government Code Section 14837(d)(3); or

(B) A manufacturer as defined herein that, together with all affiliates, has 100 or fewer employees.

For affected industry sectors that cover only 1 NAICS code with a homogenous product, and for which we have a complete list of no more than 10 affected facilities in the entire sector (cement production, hydrogen production, lime manufacturing, nitric acid production, and iron & steel production), staff invested the time to query each facility's parent company one-by-one in the Dun & Bradstreet Selectory database (D&B 2010) to determine if they meet both the revenue criteria above (Criteria 5(A)) and the number of employees criteria (Criteria 5(B)). It was determined that there are no affected small businesses in these sectors.

Given that the Dun & Bradstreet Selectory database does not include all the affected entities covered by the GHG reporting program, Dun & Bradstreet data were not used to determine the number of small businesses for the remaining sectors. Instead, staff estimated the likely proportions of small businesses in each affected sector using employment statistics published by other government agencies. Only Criteria 5(B), 100 or fewer employees, was used for the estimation due to the limited scope of those employment data. This criterion provides a conservative high estimation because qualified small businesses that meet all 6 criteria will be a smaller subset of the businesses that have 100 or fewer employees. Staff used a combination of estimation techniques that are described in the following subsections.

Upper Bound Estimation. The California Employment Development Department Labor Market Information Division publishes data on the number of establishments by size category classified by the North American Industry Classification System (NAICS) (CEDD 2009).[9] This dataset contains estimated numbers of establishments that fall into nine "employment size categories" (e.g. number of establishments with "0-4 employees," "50-99 employees," "1000+ employees," etc.) for NAICS sectors at the 2-digit or 3-digit level. The NAICS codes reported by the entities that are currently in the GHG reporting program are mapped to the 2-digit or 3-digit NAICS codes in the CEDD dataset. The size categories in CEDD data are then aggregated into two employment size categories: "less than 100 employees" and "greater than 100 employees." The proportion of establishments that have less than 100 employees is calculated for each sector.

The general stationary combustion sector, the oil and gas system sector, and the suppliers of natural gas and natural gas liquid sector include facilities belonging to

[9] According to the U.S. Bureau of Labor Statistics, "an establishment is a single physical location at which business is conducted and/or services are provided. It is not necessarily identical with a company or enterprise, which may consist of one establishment or more." (US Census 2007). Examples include product and service sales offices (retail and wholesale), industrial production plants, processing or assembly operations, mines or well sites, and support operations (such as an administrative office, warehouse, customer service center, or regional headquarters). Each establishment should receive, complete, and return a separate census form. (US Census 2002)

multiple 3-digit NAICS codes. For these sectors, the proportions of "less than 100 employees" entities for the different NAICS codes are averaged to obtain a single proportion value for these sectors.

The estimated numbers of small business entities are calculated by multiplying the proportion of "less than 100 employees" establishments by the projected number of affected entities in each sector. These numbers are upper bound estimates that grossly overestimated the numbers of affected small businesses. The overestimation is due to the following reasons: 1) using only 1 of the 6 small business criteria to conduct this analysis captures a larger group of entities than the actual qualified small businesses; 2) given that a business can own multiple establishments, the actual number of affected businesses should be smaller than the number of affected establishments; and 3) given that entities with high emissions tend to have higher outputs, leading to higher revenues and driving higher fuel consumption, the entities that exceed the reporting thresholds (of 25,000 MT of CO_2e or 10,000 MT of CO_2e) are less likely to meet the revenue criteria of qualified small business. We anticipate that in reality, the proportions of "less than 100 employees" establishments should distribute unevenly at the different emissions levels (i.e. "2,500 to 10,000 MT of CO_2e" group, "10,000 to 25,000 MT of CO_2e" group, and ">25,000 MT of CO_2e" group), which determine the applicability of the regulation. The actual number of affected small businesses should be considerably smaller than the conservatively high estimates obtained using this approach. Further refinements that adjust for the uneven distribution of "less than 100 employees" entities are discussed next.

Refined Estimation. To account for the uneven distribution of small businesses at the different emissions levels, staff further refined the estimation using additional data sources and the assumption that high emitting facilities with >25,000 MT of CO_2e emissions tend to fall into the "greater than 100 employees" group.

The California Regional Economies Employment (CREE) Dataset published by the California Employment Development Department (CREE 2008) contains total numbers of establishments in each sector by NAICS codes up to the 6-digit level. The NAICS codes reported by the entities that are currently in the ARB GHG reporting program are mapped to the CREE data to obtain the maximum potential numbers of establishments in each affected sector. The total number of establishments is multiplied by the proportion of "greater than 100 employees" to obtain an estimated total number of entities that have greater than 100 employees. The estimated number of affected small business entities is the difference between the projected number of affected entities and the estimated number of "greater than 100 employees" entities. If the estimated number of "greater than 100 employees" establishments is substantially greater than the projected number of affected entities for an industry, it is an indication that all the top ranking employers in this industry are probably subject to GHG reporting, and we conservatively assumed that there is at least 1 small business entity in this sector.

The sector of suppliers of petroleum products is not specific to any one NAICS code, and the numerous NAICS codes that it potentially covered resulted in tens of thousands

of establishments counted in the CREE dataset. Also, the CREE dataset does not have establishment counts for the potential NAICS codes covered under the supplier of natural gas and natural gas liquids sector. For these fuel supplier industries, the number of affected small business entities are calculated by multiplying the estimated proportion of "less than 100 employees" entities by the lower bound and higher bound of the projected number of total entities. Similarly, general stationary combustion facilities include numerous NAICS codes that resulted in tens of thousands of establishments counted in the CREE dataset. The likely number of small business entities is estimated by multiplying the projected number of affected entities by 37%, the proportion of small businesses based on sampling 25 existing general stationary combustion entities that staff individually queried using the Dun & Bradstreet Selectory database (D&B 2010).

The electricity deliverer, electricity generation, and cogeneration entities are aggregated under NAICS code 221. Since there is no one-to-one correspondence between the regulation sectors and NAICS codes, CREE does not inform the total number of establishments that are utilities versus electricity generation or cogeneration facilities. For electricity deliverers, staff estimated the number of potential small business entities by first eliminating the utilities owned by local governments or other large well-known energy corporations from the current reporter list, then multiplying the remainder by the estimated proportion of "less than 100 employees" establishments obtained from CEDD. For facilities subject to electricity generation and cogeneration regulation requirements, staff estimated the number of potential small business entities by multiplying the total number of establishments in NAICS code 22111 (electricity power generation) by the proportion of "less than 100 employees" entities.

Using the estimation techniques described above, staff conservatively estimated that there may be approximately 186 small business entities affected by the proposed regulation, with an upper bound no greater than 268. The estimated numbers of affected small business entities by sector are summarized in Table VI-5. Again, these numbers likely represent an overestimation due to the use of only 1 (out of the 6) small business criteria and also due to multiple establishments owned by one business. The actual number of affected businesses should be smaller than the number of affected establishments.

Table VI-5. Estimated Numbers of Affected Small Business Entities

Industry sector	Number of reporting entities	Proportion of establish-ments with <100 employees	Maximum number of establishments in covered NAICS	Estimated number of small business entities	Upper bound estimate
Cement Production	10	NR[1]	21	0	NR[1]
Electricity Deliverers	88	23%	62	5	21
Electricity Generation	192	23%	284	39	45
Cogeneration	55	23%		11	13
Petroleum Refineries	24	19%	25	4	5
Hydrogen Production	6	NR[1]	63	0	NR[1]
Stationary Combustion	184	42%	>10,000 [2]	68	78
Glass Production	15	64%	15	10	10
Lime Manufacturing	1	NR[1]	5	0	NR[1]
Nitric Acid Production	2	NR[1]	26	0	NR[1]
Pulp & Paper Manufacturing	9~11	47%	51	1	6
Iron & Steel Production	1	NR[1]	55	0	NR[1]
Oil & Natural Gas Sys	47	44%	169	1	21
Suppliers of Petroleum Products and Biofuels	45~60	67%	>10,000 [2]	30	41
Suppliers of Natural Gas and NGL	40~58	42%		17	25
Suppliers of CO_2	7	34%	63	1	3
TOTAL	**~750**			**~186**	**~268**

Table notes:
1. Staff conducted one-by-one query of the affected facilities in the Dun & Bradstreet Selectory database and found no small business entities affected by the regulation in this sector. Therefore, the proportion of "less than 100 employees" and upper bound estimate are not relevant.
2. These industries are not specific to any one NAICS code, and the numerous NAICS codes that it potentially covered resulted in a maximum potential of more than ten thousand establishments counted in the CREE dataset.

D. Economic Impacts of Proposed Regulation

This section presents the results of staff's analysis on the economic impacts of the proposed regulation. We first present a state-wide overview of the cost impacts by affected sectors, which includes all of the affected entities in the private and public sectors. The following subsections discuss the impacts on private businesses, small businesses, state and local agencies, consumers, employment, business creation and elimination, and California business competitiveness.

1. Overview of State-Wide Costs by Sector

Only the direct incremental costs of complying with the proposed reporting regulation, beyond the costs that most facilities would already incur in meeting either the extant California requirements or the U.S. EPA requirements, are included in this analysis.

Using the methods described above in Section C, staff's estimates of the cost impacts for each affected sectors are summarized in Table VI-6, which include all the affected entities in the private and public sectors.

Table VI-6. Statewide Incremental Cost Impacts by Sector

Sector	Number of Reporting Entities	Incremental Costs ($1,000)[1]			
		First-Year	[Range]	On-going Years	[Range]
Cement Production	10	10	[3 : 20]	10	[3 : 20]
Electricity Deliverers	88	-150	[-34 : -250]	-230	[-110 : -350]
Electricity Generation	192	-240	[-180 : -390]	-260	[-150 : -330]
Cogeneration [2]	55	-29	[-31 : -34]	-52	[-35 : -50]
Petroleum Refineries	24	180	[66 : 530]	110	[36 : 250]
Hydrogen Production	6	58	[30 : 162]	51	[26 : 155]
Stationary Combustion	184	920	[420 : 1,800]	580	[220 : 1,200]
Glass Production	15	67	[32 : 110]	48	[24 : 96]
Lime Manufacturing	1	5	[3 : 9]	4	[2 : 7]
Nitric Acid Production	2	31	[16 : 50]	22	[12 : 45]
Pulp & Paper Manufacturing	9~11	49	[23 : 90]	23	[10 : 49]
Iron & Steel Production	1	5	[3 : 9]	4	[2 : 7]
Oil & Natural Gas System [3]	47	650	[200 : 1,800]	510	[140 : 1,600]
Suppliers of Petroleum Products and Biofuels	45~60	1,170	[390 : 2,200]	720	[320 : 1,300]
Suppliers of Natural Gas and NGL	40~58	650	[180 : 1,500]	400	[150 : 860]
Suppliers of CO_2	7	42	[26 : 73]	36	[18 : 53]
STATE-WIDE TOTAL	**approx. 750**	**3,400**	**[1,200 : 7,700]**	**2,000**	**[700 : 4,900]**

Table notes:
1. All costs are in 2009 dollars. A negative cost number indicates a cost saving.
2. The cogeneration sector consists of facilities whose primary business is cogeneration. This does not include cogeneration units that are a part of a larger industrial operation.
3. For the oil and gas system sector, the costs shown here do not include the baseline costs to comply with U.S. EPA Subpart W.

As shown in Table VI-6, the proposed rule revision is expected to have a net state-wide incremental cost impact of $3 million ($1–$8 million) in the first year and $2 million ($1–$5 million) in the on-going years. Using a discount rate of 5% and a time horizon of 10 years, the total state-wide costs are approximately $18 million ($6 to $43 million) over 10 years. A 10-year time horizon is assumed for the analysis because ARB staff expects that the GHG reporting regulation may potentially be revised again between 2012 and 2022, due to potential new federal regulations or cap-and-trade program requirements.

The electricity deliverer, electricity generation, and cogeneration sectors can expect to see a net incremental cost saving from the revised regulation due to reductions in California reporting requirements. The other sectors are expected to see a net

incremental cost increase due to additional monitoring, sampling, and reporting requirements in the proposed regulation. State-wide, most of the incremental costs are borne by those entities that are new to GHG reporting, including suppliers of fuels (approximately 46% of state-wide costs) and general stationary combustion sources that emit 10,000 to 25,000 MT of CO_2e that will be new to GHG reporting under the proposed regulation (approximately 23% of the state-wide costs). In addition, the oil and gas sector is expected to incur approximately 19% of the state-wide costs due to the additional monitoring and sampling requirements proposed in this revised regulation. The incremental costs to the other sectors make up the remaining 12% of the state-wide costs. The distribution of net costs and net savings by sectors over the 10-year time horizon are graphically presented in Figure VI-3 and Figure VI-4, respectively.

The main sources of uncertainties in the economic impact analysis are from the ranges of wage rates in the U.S. Bureau of Labor Statistics data and the ranges of the estimated time requirement to perform compliance tasks. The high estimates shown in the cost table represent the worst case scenario, in which all the affected entities in each sector use staff whose salary is high in their respective staff class, and the amount of time that the high-salaried staff takes in doing the compliance tasks is also on the high end of the range of estimates. On the other hand, the low estimates represent the best case scenario, in which all the affected entities in each sector use staff whose salary is on the low side of the wage rate range, and each staff takes little time to accomplish the compliance tasks. The high and low estimates are shown here for bounding purposes, and they are extremely unlikely in reality because there is a diversity of facility staff salaries and efficiencies across the sector. When factoring in all uncertainties in either direction, the net costs are likely to be close to the middle estimates.

Figure VI-3. Distribution of Net Incremental Costs by Industry Sector

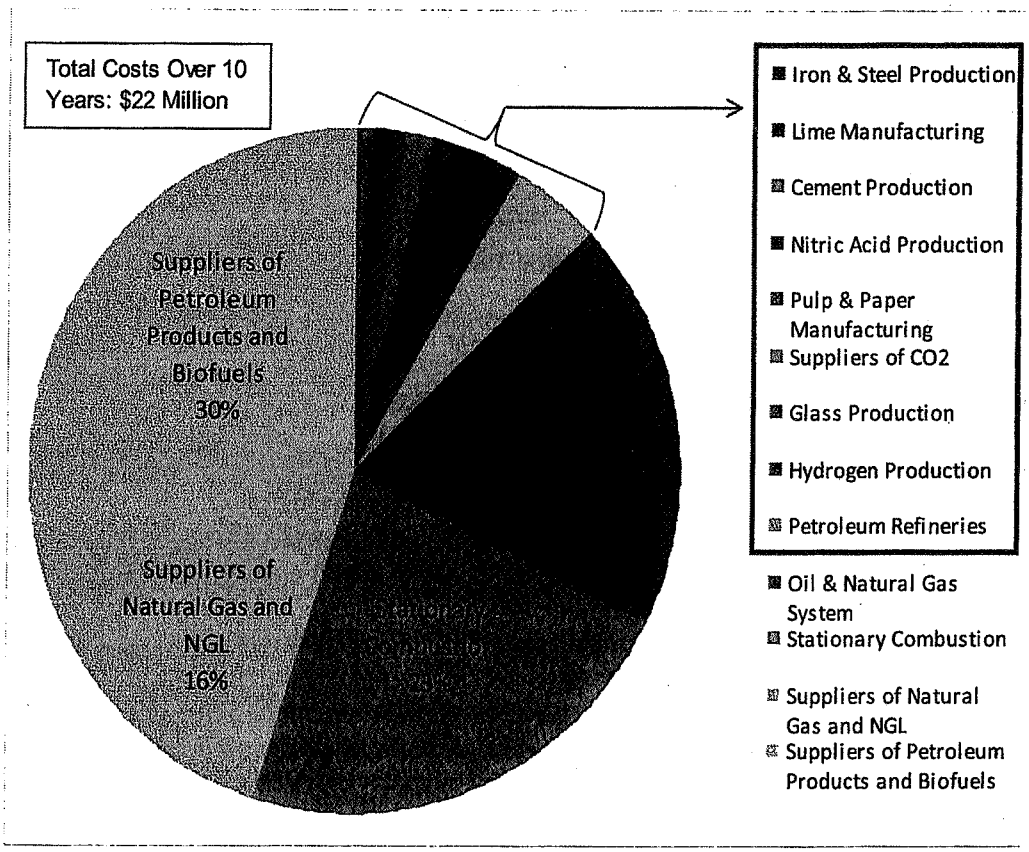


Figure VI-3. Distribution of Net Incremental Costs by Industry Sector

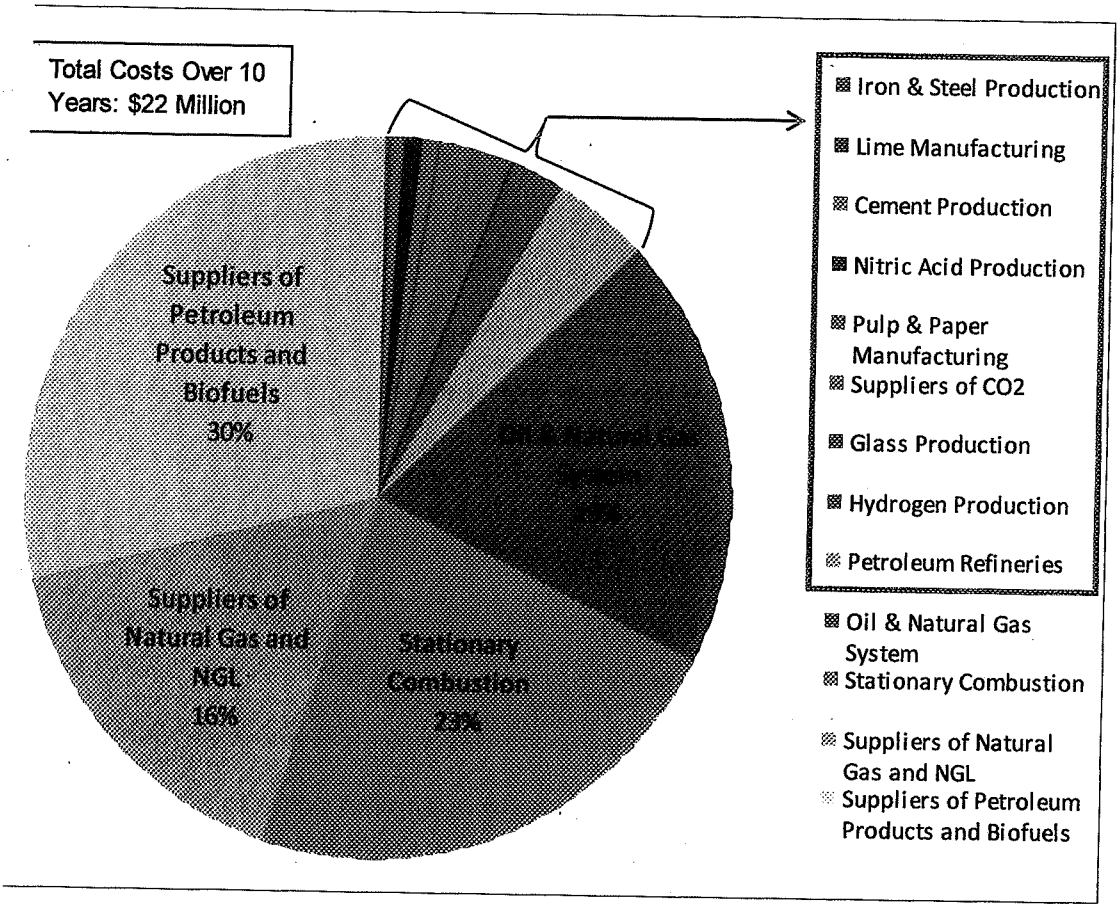


Figure VI-4. Distribution of Net Incremental Saving by Industry Sector

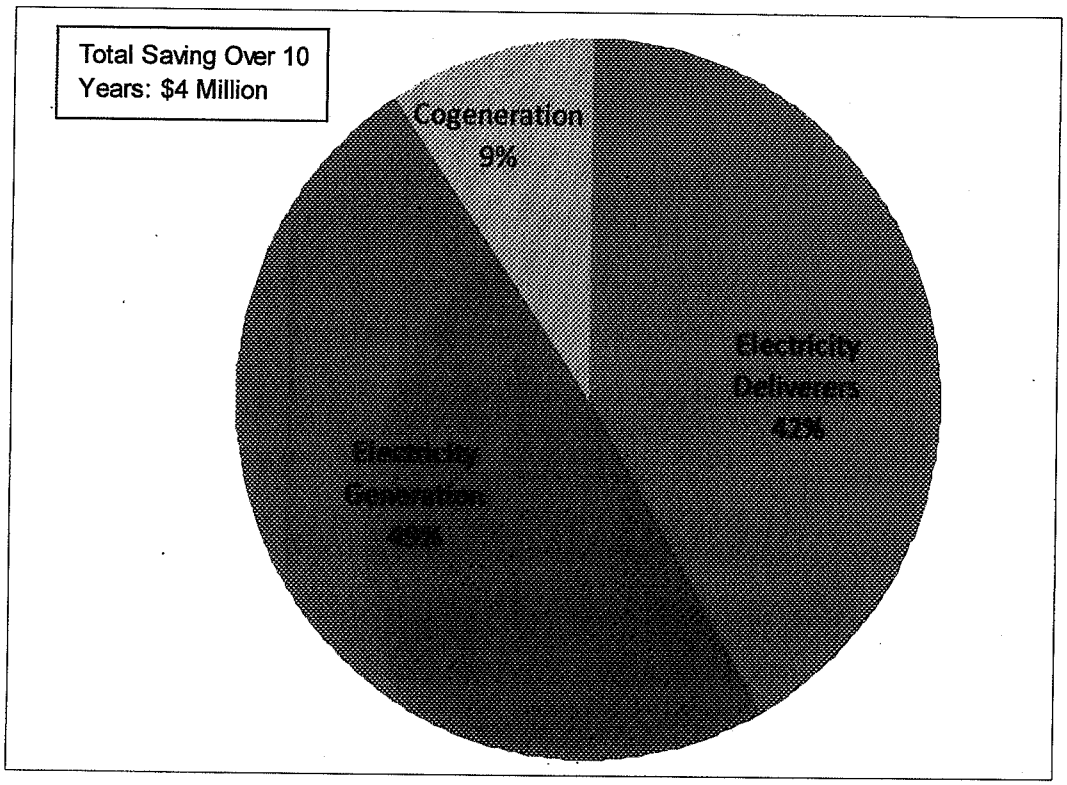


Table VI-6, Figure VI-3, and Figure VI-4 show the estimated costs to all affected entities in the private and public sectors. The total state-wide costs broken down by private and public entities are shown in Figure VI-5. The private sector incurs a majority of the incremental costs, while the net saving is distributed equally in the private and the public sectors. The cost impacts on private businesses and state and local government are discussed in further details in the following sections.

Figure VI-4. Distribution of Net Incremental Saving by Industry Sector

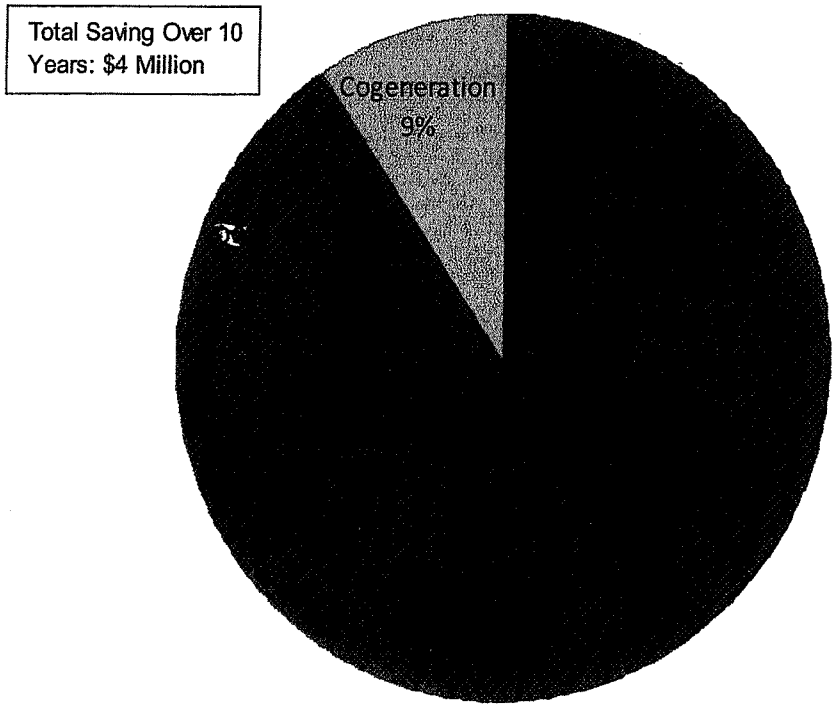
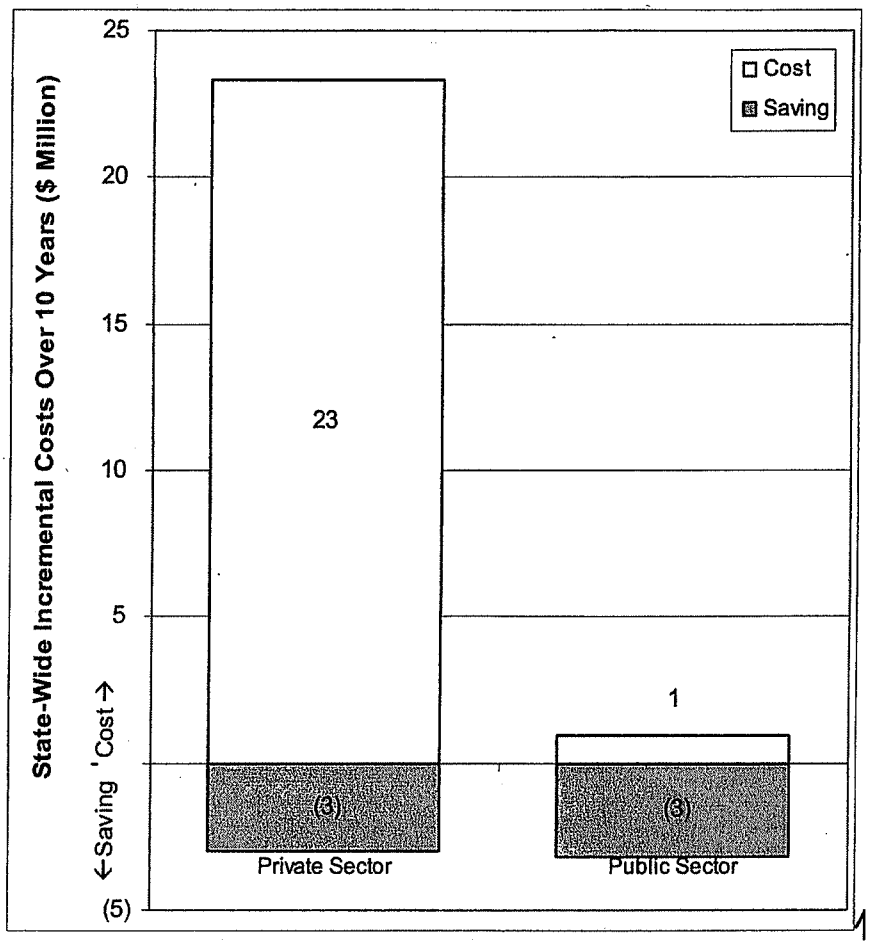


Table VI-6, Figure VI-3, and Figure VI-4 show the estimated costs to all affected entities in the private and public sectors. The total state-wide costs broken down by private and public entities are shown in Figure VI-5. The private sector incurs a majority of the incremental costs, while the net saving is distributed equally in the private and the public sectors. The cost impacts on private businesses and state and local government are discussed in further details in the following sections.

Figure VI-5. State-wide Costs Incurred by Private and Public Entities



2. Impacts to California Businesses

The proposed GHG reporting regulation focuses on the largest stationary sources of GHG emissions and other sources that must be included for an effective cap-and-trade program. The majority of the GHG reporting costs will be incurred by private businesses.

The incremental costs for typical businesses subject to the proposed rule revisic.. will generally be small for facilities that are already subject to current GHG reporting programs, because the bulk of the baseline costs will be incurred complying with the U.S. EPA regulation (USEPA MRR 2009-2010) and the existing ARB reporting regulation (ARB MRR 2007). For an individual reporting entity, the incremental cost per entity could range from a worst case estimate of an additional cost of $80,000 for a petroleum refinery to a best case estimate of a cost saving of $10,000 for an electricity deliverer entity.

The specific incremental cost for a facility subject to GHG reporting can vary significantly depending on each facility's unique situation in terms of its sector designation, type and size of its fuel combustion equipment, facility complexity, emissions level, and its current monitoring and sampling practices as compared to its future requirements under this proposal. Staff anticipates that those general stationary combustion facilities that are new to the GHG reporting program but emit less than 25,000 MT of CO_2e and can use the abbreviated reporting option will incur a new cost of approximately $1,000 to $3,000 per facility. Facilities that are not currently reporting to California but will be subject to U.S. EPA reporting rule are expected to incur all new verification costs. Complex facilities with a large number of processes or that require ongoing monitoring of fuels, such as refineries, will have higher verification costs (including verification service costs and company staff labor costs) which could range from $8,000 to over $60,000 per year. Relatively simple facilities, such as a glass production plant, can expect to see relatively lower reporting and verification costs, between $1,000 and $5,000 per year. Staff anticipates that the incremental costs of oil and gas entities will vary significantly among entities, ranging from $5,000 to $45,000 per year. Costs per reporting entity by industry sectors are presented in Table VI-7.

Some reporting entities are expected to see a net cost saving as the result of the proposed regulation. Within the electricity deliverer, electricity generation, and cogeneration sectors, three sectors that are expected to see a net incremental saving sector-wide, most facilities may see reduced costs due to reductions in reporting requirements, although some may experience a slight cost increase. Electricity generating or cogeneration facilities that emit less than 10,000 MT of CO_2e, but are currently reporting to ARB under a more stringent threshold of 1 MW and 2,500 MT of CO_2e, will likely see reduced costs because the proposed rule has significantly reduced their reporting efforts through the abbreviated reporting provision. Electricity generating or cogeneration facilities emitting less than 10,000 MT of CO_2e will experience a cost saving because they will no longer be required to report their emissions under the revised rule. Electricity retail providers (2/3 of which are public utilities) can also expect a cost saving due to significantly reduced reporting requirements. State-wide, approximately 58% of the net saving is in the electricity generation and cogeneration sector, and the remaining net saving is in the electricity deliverer sector.

Table VI-7. Range of Incremental Cost Impacts per Reporting Entity by Sectors in the On-going Years

Sector	Incremental Costs Per Entity in the On-going Years ($1,000)[1]	
	Low	High
Cement Production	<0.5	2
Electricity Deliverers	-10	<0.5
Electricity Generation	-9	3
Cogeneration[2]	-9	1
Petroleum Refineries	-1	81
Hydrogen Production	4	26
Stationary Combustion	<0.5	13
Glass Production	<0.5	7
Lime Manufacturing	2	7
Nitric Acid Production	6	22
Pulp & Paper Manufacturing	<0.5	7
Iron & Steel Production	2	7
Oil & Natural Gas System[3]	10	45
Suppliers of Petroleum Products and Biofuels	6	20
Suppliers of Natural Gas and NGL	<0.5	21
Suppliers of CO_2	3	8

Table notes:
1. All costs are in 2009 dollars. A negative cost number indicates a cost saving. Due to the complex baselines and the diversity of the facility types within an industry sector, some facilities in the same sector may experience a cost saving, while some may experience an incremental cost increase. (See Sections C.1 and C.2.)
2. The cogeneration sector consists of facilities whose primary business is cogeneration. This does not include cogeneration units that are a part of a larger industrial operation.
3. For the oil and gas system sector, the costs shown here do not include the baseline costs to comply with U.S. EPA Subpart W.

The sources of uncertainties for the cost per entity estimates come from ranges of wage rates and time requirements to perform compliance tasks. Similar to the state-wide costs by sectors, the high estimates represent the worst case scenario in which high-salaried facility staff take many hours to perform compliance tasks. In addition, because facilities within the same sector can be further categorized into more detailed facility types depending on how they are affected by the revised regulation (see Section C.2—Costs Categorization of Affected Facilities for a discussion of the facility categorization), a wide range of values for cost per entity can be expected even within the same sector.

With the proposed revisions, we anticipate that initial year costs will be highest, as reporters modify internal GHG reporting systems, become familiar with the new requirements, install any new equipment, and develop expertise with the new reporting systems and methods. We anticipate industry costs to decline over time as the revised GHG reporting requirements become incorporated into standard facility practices.

The Oil and Gas Sector and the Subpart W Baseline

For the oil and gas sector, under the likely scenario that U.S. EPA adopts Subpart W by the time that this proposal is promulgated, the incremental costs for implementing the proposed rule state-wide are approximately $0.7 million ($0.2—$2 million) in the first year and $0.5 million ($0.3—$1.5 million) in the on-going years. Each entity may possibly see an incremental cost increase of $5,000 to $52,000 in the first year and $2,000 to $45,000 in the subsequent years.

Under the unlikely scenario that U.S. EPA does not adopt Subpart W by the time that this proposed rule is promulgated, in which case the incremental costs are the sum of the costs to comply with Subpart W as well as the additional tasks required by the proposed California regulation, the total incremental costs to the oil and gas sector state-wide are projected to be in the range of $0.6 to $3 million in the first year, and $0.4 to $2 million in the on-going years. In this scenario, each entity may possibly see an incremental cost increase of between $16,000 and $76,000 in the first year and between $9,000 and $60,000 in the on-going years.

3. Impacts to Small Businesses

Using a combination of estimation techniques described in Section C of this chapter, staff conservatively estimated a total of approximately 186 small business entities that may be affected by the proposed regulation revision (with an upper bound estimate of no more than 270 small business entities). Other than their high-level industry sector designation, we do not know exactly how these small business entities distribute among the 48 facility categories, which determine whether an individual entity may incur a net incremental cost or see a net incremental savings. Nevertheless, we expect that more small businesses may be in the 10,000 to 25,000 MT of CO_2e category that are eligible for abbreviated reporting, and they should incur relatively less total costs than their counterparts with emissions >25,000 MT of CO_2e.

The estimation results presented in Table VI-5 show that approximately 40% of the small businesses may be in the general stationary combustion sector, 30% may be in the electricity generation and cogeneration sector, and 10% may be in the fuel supplier sector. The incremental costs among the facilities in these three sectors can vary significantly. Based on the estimation described in Section C, a small general stationary combustion facility in the <25,000 MT of CO_2e category may see an incremental cost ranging from a few hundreds dollars to an upper bound of $7,000. Because some small electricity generating and cogeneration facilities are relieved from certain reporting requirements, and some may no longer need to report, a facility in this sector may see an incremental savings of $3,000 to $7,000. On the other hand, small fuel suppliers may be newly subject to GHG reporting under the revised regulation, with a likely incremental cost ranging from $2,000 to $13,000.

4. Impacts to California State and Local Agencies

Using the methods described previously, we have estimated that State and local agencies will likely see an overall cost savings as the result of this proposal. The local

governments and agencies that could be subject to reporting include some cities, counties, public utility districts, or agencies that maintain facilities such as landfills, sewage treatment plants, electricity generating or cogeneration units, or publicly owned electricity providers that meet the applicability criteria. In general, publicly owned electricity deliverers and electricity generating or cogeneration facilities with <25,000 MT of CO_2e emissions will see a net savings, while the other types of facilities will see an incremental cost increase. Statewide, the overall savings to local government entities are approximately $2 million ($1-3 million), and the savings to state government entities are approximately $50,000 ($30,000-$60,000) over the 10-year time horizon using a 5% discount rate. The incremental costs and savings are summarized in Tables VI-5 and VI-6.

Table VI-8. Costs to Local Government Entities Subject to Reporting

Facility Type	Number of affected entities	Total Costs over 10 Years ($million)[1]	
		Best Estimate	Range
Electricity Deliverer (municipal utilities/joint power)	41	-1.3	[-0.6: -2.0]
Facilities with EGU/cogen, >25,000 MT of CO_2e	46	0.6	[0.2 : 1]
Facilities with EGU/cogen, <25,000 MT of CO_2e	35	-1.6	[-0.8 : -2.5]
Other facilities	approx. 12	0.3	[0.1 : 0.5]
SUM	**134**	**-2**	**[-1 : -3]**

Table notes:
1. All costs are discounted by 5% over 10 years and stated in 2009 dollars. A negative cost number indicates a cost savings.

Table VI-9. Costs to State Government Entities Subject to Reporting

Facility Type	Number of affected entities	Total Costs over 10 Years ($1000)[1]	
		Best Estimate	Range
Electricity Deliverer	1	-15	[-7: -30]
Facilities with cogen, >25,000 MT of CO_2e	7	13	[-6 : 50]
Facilities with cogen, <25,000 MT of CO_2e	2	-77	[-40 : -100]
Other facilities	approx. 3	27	[10 : 50]
SUM	**13**	**-50**	**[-30: -60]**

Table notes:
1. All costs are discounted by 5% over 10 years and stated in 2009 dollars. A negative cost number indicates a cost savings.

Adoption of the proposed revisions is expected to require new funding for ARB to administer the program. Approximately 2.0 staff members will be redirected from existing staffing to administer the new program beginning in FY2011/2012. In addition, approximately $250,000 per year will be required over a three-year period for reporting system improvements as staff works to integrate California reporting with U.S. EPA reporting systems, and then an additional $150,000 per year is needed on an ongoing basis for operations and maintenance of the reporting systems. These costs are not included in existing budgeting and additional funds are needed to implement the proposed revisions to the regulation.

5. Potential Impact on Consumers

No noticeable change in consumer prices is expected from the reporting regulation because the compliance costs will have only a minor impact on the affected businesses.

6. Impact on Employment

Since the incremental compliance costs associated with the revised GHG reporting regulation impose only a very small impact on California businesses, staff expects no significant change in employment due to the regulation revision. However, the regulation could theoretically impose hardship on some businesses operating with little or no margin of profitability, affecting the creation or elimination of jobs in California.

Staff estimated that the proposed revisions to the regulation will likely result in a small number of additional jobs in the technical consulting business. The adoption of the existing GHG reporting regulation has already led to accreditation of 230 new verifiers to date (see Section IV of this report). Most of these verifiers are existing technical consultants that have expanded their areas of business into providing annual verification services, but some may be new positions created to support the verification workload. To estimate the number of new verifier positions that may be needed under the revised regulation, staff scaled up the number of verifiers accredited by ARB to date (230) by the ratio of the expected number of GHG reports under the revised regulation and the number of the current GHG reports (750/609). To account for the part-time nature of verification work, we conservatively assume that for every four such new verifier positions demanded, only one new job will be created. It is estimated that 10 to 20 new verification jobs could be created to provide these additional services required by the proposed regulation.

For technical consulting jobs to assist reporting entities with GHG reporting activities, staff conservatively assumes that there will be no noticeable increase in consulting jobs, but we anticipate that work may be shifted to support the new reporting needs due to new or more complicated reporting requirements. Many facilities will hire consultants to setup GHG reporting systems in the first 2 years of rule implementation. However in the on-going years, some may choose to carry on GHG reporting with in-house staff without retaining a consultant's assistance. There may be an initial growth in consulting business, but the growth will likely level off after 2 to 3 years. Staff expects that most consulting work will be done by existing firms and employees, and some of the work will

be performed by firms outside of California. Current capacity in the technical consulting firms likely can support the additional requirements imposed by the proposed regulation. Precise estimates of the number of new jobs created are not possible.

7. Impact on Business Creation, Elimination, or Expansion

No change is expected to occur in the status of California businesses as a result of the reporting regulation. This is because the proposed regulation is expected to impose a minor cost on businesses in California. However, should the regulation impose significant hardship on California businesses operating with little or no margin of profitability, some small businesses may be forced out of the market or decide not to expand in California. Also, in theory, some businesses could possibly decide against coming to California to avoid having to report their GHG emissions.

Staff anticipates that although there may be new consulting and verification jobs created, there will be no noticeable changes in the number of businesses created, eliminated, or expanded as the result of the propose regulation. Existing firms will likely attempt to absorb as much of the new workload as possible, and the amount of spill-over available to new companies cannot be clearly determined.

8. Impacts to California Business Competitiveness

The regulation would have little or no impact on the ability of California businesses to compete with businesses in other states. This is because the regulation does not impose a significant cost impact on California businesses. In addition, many of the businesses affected by the regulation are local businesses serving California clients, and may not be strongly subject to interstate competition. However, the proposed regulation could have an adverse impact on the ability of some California businesses operating with little or no margin of profitability to compete with businesses in other states.

VII. ALTERNATIVES TO THE PROPOSED REGULATION

California Government Code section 11346.2 requires ARB to consider and evaluate reasonable alternatives to the proposed regulatory action and provide reasons for rejecting those alternatives. This section discusses alternatives evaluated and provides reasons why they were not included in the proposed revised regulation. ARB staff did not find any of the alternatives considered to be more effective in carrying out the purpose for which the proposed revised regulation is intended, or to be as effective or less burdensome to affected businesses, than the proposed revised regulation.

A. Take No Action Alternative

A "no action" alternative means that no revisions would be made to the existing California GHG reporting regulation. Essentially, ARB and reporting entities would continue to operate pursuant to the requirements of the existing regulation. If ARB were to take no action, reporting entities subject to the existing GHG reporting regulation would prepare a California-specific emissions data report which was not harmonized with federal U.S. EPA reporting requirements, resulting in potential confusion, duplicative reporting efforts, and additional, unnecessary costs to California businesses subject to GHG emissions reporting. In addition, the ARB would incur additional burdens in resolving inconsistencies between reporting programs, maintaining redundant data systems, and providing additional user support.

By developing the current proposal, the California GHG emissions reporting requirements are substantially harmonized with U.S. EPA's mandatory GHG reporting requirements for most industrial sectors. The intention of the proposed revisions and harmonization is to allow emissions data reports prepared for California GHG emissions reporting to also meet the requirements of U.S. EPA's GHG emissions reporting. This reduces costs and duplicative reporting for California businesses. ARB is working with U.S. EPA to develop a mechanism so that ARB GHG emissions data reports can be submitted directly to U.S. EPA, rather than submitting separate California and U.S. EPA reports based on disparate requirements, methods, and emission reporting systems.

In addition, the current ARB regulation for mandatory GHG reporting is not sufficiently rigorous to support a cap-and-trade program for GHG emissions. For example, under the current regulation certain large combustion sources may simply use default emission factors for estimating their emissions, which is not sufficient for a cap-and-trade program. Or, under the current regulation, if certain critical data are missing, fully defined methods are not provided for providing the missing data. Also, under the current regulation many industry sectors are not required to report their process emissions. These changes and many other improvements have been added to the proposed regulation as part of the U.S. EPA harmonization and as needed for cap-and-trade. The development and implementation of a credible cap-and-trade program would not be possible under the existing regulation without the addition of a separate and additional regulatory process to require reporting of additional data needed to support cap-and-trade.

As such, the "no action" alternative would increase costs for reporting entities because they would be faced with submitting two completely separate emissions data reports, and would not sufficiently support California's cap-and-trade program, whereas the proposed regulatory action would reduce reporting costs and avoid duplication by harmonizing substantial portions of the California GHG reporting regulation with U.S. EPA reporting requirements, while also including revisions to support a rigorous and stringent cap-and-trade program. For all of these reasons, the "no action" alternative was rejected.

B. Retain Existing Rule and Create New Mechanism for Collecting Cap-and-Trade Data

Another option that was considered was to retain the existing ARB rule, and create a separate regulatory reporting process to collect the additional data needed to support a viable cap-and-trade program. This option fails on several levels. First, it would add a third reporting program to the existing ARB reporting and U.S. EPA greenhouse gas reporting. Second, the benefits of harmonizing with the U.S. EPA reporting program, providing more consistent reporting and lower costs would not be realized. Third, the ARB would need to implement another new regulatory program, which would unnecessarily increase burdens on those subject to the cap-and-trade program, and create new, and sometimes redundant administrative and technical workload for the ARB. For these reasons, this option was rejected.

C. Create Regulation that is 100% Consistent with U.S. EPA Regulation or Revoke Existing ARB Regulation

ARB staff considered revising the California GHG reporting regulation to be completely consistent with the U.S. EPA reporting requirements for GHG emissions, essentially adopting the U.S. EPA regulations "as is." Or, in the same vein, we considered revoking the existing ARB GHG reporting regulation so that ARB would obtain GHG data solely from the U.S. EPA reporting program.

The regulation is being revised to not only harmonize with U.S. EPA GHG reporting requirements, but to also support a California cap-and-trade program. The current U.S. EPA reporting regulation is not sufficiently rigorous to support a cap-and-trade program. For example, U.S. EPA's regulation allows the use of default emission factors which would not provide emissions that are sufficiently accurate to support market-based emissions trading. The proposed revised ARB regulation limits the use of default emission factors in order to ensure the accuracy needed for a cap-and-trade program. The ARB proposed revised regulation also provides more prescriptive methods for handling missing data than the U.S. EPA requirements, which are not always sufficient to support the accuracy needed for a cap-and-trade program. In addition, electric power entities and operators of petroleum and natural gas systems are not required to report under the U.S. EPA regulation, but these sectors are critical for California's GHG emissions accounting.

For these reasons, adopting the U.S. EPA reporting regulation "as-is," or simply revoking the existing ARB regulation, would not effectively support critical ARB program needs, and ARB has therefore rejected this alternative

D. Modify the Existing California Regulation to Support Cap-and-Trade Program Needs without Harmonizing with U.S. EPA Reporting Requirements

Another option considered by ARB staff was to modify the existing ARB regulation so that it would meet cap-and-trade and other program needs, without consideration of the U.S. EPA reporting requirements. If the current ARB regulation was modified without consideration of the U.S. EPA reporting requirements, and similar to the "take no action" alternative, reporting entities would essentially be subject to two completely independent GHG reporting programs – one at the State level and one at the Federal level. Requiring facilities to develop and submit separate emissions data reports based on completely different requirements and specifications would be confusing and create additional costs. In addition, the ARB would incur additional burdens in resolving inconsistencies between reporting programs, maintaining redundant data systems, and providing additional user support.

In assessing this alternative, it quickly became apparent that including revisions to harmonize with U.S. EPA reporting requirements, along with the proposed revisions to support a cap-and-trade program, would provide efficiency and cost savings to both reporting entities and ARB. By using the U.S. EPA regulation as a baseline for the proposed revisions, and including additional California-specific modifications to ensure the stringency and accuracy necessary for California's cap-and-trade program, ARB is allowing reporting entities to use essentially the same methods and assumptions as other reporting entities throughout the nation, providing state-to-state consistency. This is important for existing or future regional and national GHG trading programs.

ARB staff chose not to pursue the alternative of modifying the existing California reporting regulation to support cap-and-trade without harmonizing with U.S. EPA reporting requirements because it does not produce the same cost savings and reduced duplication as the proposed regulatory action, and would in fact increase costs and duplication. For all these reasons, ARB staff rejected this alternative.

E. Alternatives to Proposed Verification Requirements

Under the current GHG reporting regulation, ARB has about 230 accredited verifiers and 45 accredited verification bodies, all of whom have all met strict eligibility criteria under the existing regulation, taken ARB verifier training, and successfully passed an examination at the end of the training. These firms and individuals would be able to continue to provide verification services under the proposed revised regulation once the existing accredited verifiers have attended an ARB training workshop to learn the new reporting requirements under the proposed regulation.

ARB staff considered the following alternatives to assess the stringency and functionality of independent third-party verification in the proposed regulatory action.

Make No Changes to Current Verification Requirements.
The current verification requirements are based on best practices for GHG verification and are sufficient to provide a good foundation for a GHG reporting program. However, experience implementing the current requirements has shown the need to clarify a few areas in the existing regulation for program consistency. That includes requirements for how to assess for material misstatement and activities at site visits. The transition to a cap-and-trade program also highlights the need for a third verification statement option that acknowledges the quality of the data when there is a non-conformance that does not lead to a material misstatement and a need to develop a facility emissions number that is the basis for a compliance obligation when the emissions data report does not pass verification. These small additions to the existing verification requirements are needed to support the needs of a cap-and-trade. As such, ARB staff chose not to simply maintain the current verification requirements without making necessary revisions.

Require a Less Comprehensive Verification Process.
The verification requirements in the regulation constitute a program that will ensure data accuracy and oversight of emissions reporting to support the cap- and-trade program. To allow any less stringency in the verification process would diminish data accuracy, risk compromise of data through economic conflict of interest, limit ARB's ability to oversee the reporting process, and result in a GHG reporting program that has less stringency than comparable existing programs in the European Union Emission Trading Scheme and California's proposed requirements for the Western Climate Initiative. Given the need for extremely accurate, high quality emissions data, ARB staff has rejected this alternative.

Allow Self-Verification of Emissions Data Reports.
Staff considered the recommendation of several stakeholders to allow the higher level personnel at affected facilities to self-verify the emissions reports. The stakeholders argued that company chief executive or operating officers would sign the reports and face penalties of perjury for any misstatement. Staff rejected this alternative because most emission reports submitted voluntarily have been found by independent verifiers to contain errors and factual misstatements, often unintended, that the signatories did not and cannot be expected to have discovered. Trained, experienced, independent verifiers provide the dispassionate expertise to help assure the accuracy expected by international standards and required to support a program where intangible goods such as greenhouse gas emissions are now a monetized commodity.

Use ARB Staff for Verification.
Before proposing independent third-party verifiers, staff explored the use of ARB staff as verifiers. The State would need to add numerous staff and resources to be able to effectively verify the hundreds of submitted emissions reports. Staff estimated that over

150 dedicated positions would be needed to spend the time required for site visits to examine sources, draw up sampling plans and risk assessments, check emissions calculations, and develop and issue verification reports and opinions. By requiring the use of third-party verifiers, including the experts already working as verifiers under the current GHG reporting regulation, California is able to remain consistent with existing GHG reporting programs and assure data quality, while creating opportunities for highly skilled positions in the private sector. Under the staff proposal, ARB will continue to provide training and oversight of verifiers, and carry out audits to assure a consistent, fair and robust verification process needed to support the cap-and-trade program. Therefore, given the existing and functioning third-party verification program under the current GHG reporting regulation, ARB staff has rejected this alternative.

Use the U.S. EPA Verification Process.
Staff reviewed the current verification process in the U.S. EPA regulation before proposing that California stay with its existing process of independent, third-party verification. The U.S. EPA regulation contains a verification process that relies on automated routines to screen submitted emissions data reports for inconsistencies and flag data that do not meet certain criteria. Although this process is termed "verification" by U.S. EPA, it is inconsistent with the international standard for verification of GHG emissions data reports. Experience with California's existing regulation has shown that errors are very common in emissions data reports and that third-party verification is important in the submittal of an accurate emissions data report, especially to ensure that all required sources are included in the emissions data report. Having a third-party verifier review each reporting entity's emissions data report ensures a careful and thorough review of all data submitted to ARB. Under the staff proposal, ARB would continue to rely on the international standard of third-party verification to ensure credible and accurate reporting to support the cap-and-trade program. As such, ARB staff has rejected this alternative.

VIII. SUMMARY AND RATIONALE FOR PROPOSED REGULATIONS

The proposed revision of the Regulation for the Mandatory Reporting of Greenhouse Gas (GHG) Emissions for California is necessary to support a California GHG cap-and-trade program and to harmonize with the U.S. Environmental Protection Agency (U.S. EPA) federal mandatory GHG reporting requirements. This section summarizes the requirements and rationale for each provision of the proposed regulations.

Subarticle 1
General Requirements for Greenhouse Gas Reporting

Summary of Section 95100, Table of Contents

This section provides a Table of Contents of the Subarticles and Sections of this article.

Rationale for Section 95100.

This section is necessary to provide an outline of the regulation and assist those subject to the regulation to understand and comply with the all sections applicable to them.

Summary of Section 95100.5, Purpose and Scope.

Summary of Section 95100.5(a).
This section describes the overall purpose of the proposed revised California greenhouse gas reporting regulation, including a brief summary of those subject to reporting, how the regulation is organized, incorporation of the U.S. EPA reporting rule for greenhouse gases, and key terms use in the regulation.

Rationale for Section 95100.5(a).
This section is necessary to provide a general orientation and framework to the regulation so that those subject to reporting understand and comply with the regulation.

Summary of Section 95100.5(b), Organization of Article.
This provision briefly describes each of the five subarticles of the regulation.

Rationale for Section 95100.5(b).
This provision is necessary to ensure that those subject to the regulation understand the structure of, and comply with, the regulation.

Summary of Section 95100.5(c), U.S. EPA GHG Reporting Rule.
This provision describes the specific incorporated U.S. EPA final rules, and dates of promulgation, to be used for the purposes of ARB GHG reporting. Within the proposed regulation, GHG emission estimation and reporting requirements adopted by the U.S. EPA are used as a basis for the proposed ARB reporting requirements.

Rationale for Section 95100.5(c).
The U.S. EPA reporting rule for greenhouse gases is undergoing regular revisions. In order to ensure consistent reporting requirements that will consistently meet ARB program needs, it was necessary to associate our proposed regulation to a specific, fixed version of the U.S. EPA reporting rule. If we did not fix our regulation to a specific date of the U.S. EPA rule, future modifications to the U.S. EPA rule could potentially weaken existing federal requirements. This would create uncertainties for a market program and require time consuming revisions to the ARB regulation in order to restore the stringency needed for our requirements. Tying the ARB regulation to the U.S. EPA regulation adopted as of a certain date minimizes this potential risk.

Summary of Section 95100.5(d), Substitution of Terms and Responsibility.
This provision substitutes the terms "Administrator" and "EPA" with "Executive Officer" and "ARB" respectively. It also clarifies the specific party responsible for reporting.

Rationale for Section 95100.5(d).
Much of the proposed regulation is based on, and refers to, the U.S. EPA greenhouse reporting regulation. Given that the controlling agency for this proposed regulation is the California Air Resources Board, it was necessary to modify the terms within the U.S. EPA regulation text to reflect that fact. The other component of this provision is necessary to clarify which party is responsible for reporting in the situation where the owner and operator of a facility are not identical. The party having operational control of the facility, and not the owner, bears ultimate responsibility for reporting. This provision is necessary to avoid ambiguity regarding who must prepare and submit the GHG report.

Summary of Section 95101, Applicability.

This section of the regulation specifies which facilities and entities are subject to greenhouse gas emissions reporting under the proposed regulation. It also specifies methods for determining applicability, which entities are excluded from reporting, the requirements for demonstrating lack of applicability, and the requirements for ceasing reporting if applicability is no longer met.

Rationale for Section 95101.
The rationales for individual components of this section are provided below. Overall, this section is necessary to specifically inform and identify those industry sectors that are subject to the regulation what conditions trigger reporting, what conditions must be met to no longer be subject to reporting, and what does not need to be reported.

Summary of Section 95101(a), General Applicability.
This provision specifies the types of reporting entities who are subject to reporting, specifies that a report must be submitted by those subject to the regulation for 2011 and subsequent calendar years, and indicates these reports must cover the sources and gases in the regulation that are applicable to the reporting entity. This provision also

clarifies that the regulation applies to entities acting as verification bodies and verifiers of emissions data reports and offset project data reports.

Rationale for Section 95101(a).
This provision is necessary to provide a framework for those who are subject to the requirements of the regulation. The new framework begins with the U.S. EPA regulation, which did not exist when the current ARB regulation was adopted. In general, facilities subject to reporting are the same as those specified in 40 CFR §98.2(a)(1)-(3) of the U.S. EPA regulation, but there are some differences in applicability. This provision is needed to indicate that entities both within and beyond the U.S. EPA reporting requirements would be required to report to ARB under the proposed regulation. The provision indicates that there are some modifications to the federal rule applied to those within its scope, and that there are some reporting entities for that are beyond the scope of the U.S. EPA rule that would be required to report in California. These specific modifications are provided within section 95101. This provision is also necessary to inform verifiers and verification bodies that the regulation applies not only to those subject to GHG reporting, but also to those entities (verification bodies and third party verifiers) that will verify submitted reports and offset project data reports.

Summary of Section 95101(b), Calculating GHG Emissions Relative to Reporting Thresholds. Some industrial sectors are required to report based on their annual emissions of CO_2e. This provision specifies the methods that must be used in computing CO_2e emissions for the purpose of determining if a facility exceeds 10,000 metric tons of CO_2e per year. The provision references the methods provided in 40 CFR §98.2(b)-(g). Modifications to the requirements of 40 CFR §98.2(b)-(g) are provided to: a) change the threshold to 10,000 metric tons of CO_2e and an aggregate maximum heat capacity of 12 mmBtu/hr or greater, b) include biomass emissions in the threshold determination, and, c) include emissions from geothermal generating units and hydrogen fuel cells in the threshold determination.

Rationale for Section 95101(b).
This provision is needed to establish the threshold for GHG reporting for sectors subject to a threshold under the terms of the federal regulation. The threshold of 10,000 metric tons of CO_2e is established because of the need to monitor compliance with the cap-and-trade rule and to monitor emissions leakage below the cap-and-trade applicability threshold of 25,000 metric tons of CO_2e, consistent with the decision of Western Climate Initiative partners. The provision is also needed to indicate how a reporting entity subject to a reporting threshold will determine whether its emissions exceed the threshold, including which types of emissions to count in assessing whether the threshold is exceeded.

Summary of Section 95101(b)(1).
This provision indicates that facilities with stationary combustion emissions should count those emissions in assessing whether the reporting threshold is exceeded. Thresholds of 10,000 metric tons of CO_2e and 12 mmBtu are established.

Rationale for Section 95101(b)(1).
A threshold of 10,000 metric tons of CO_2e is established because of the need to monitor emissions leakage below the cap-and-trade applicability threshold of 25,000 metric tons of CO_2e, consistent with the design decision of California and other WCI Partner jurisdictions. The additional heat input capacity threshold of 12mmBtu/hr or greater is established to provide reporters an easy means of assessing whether the emissions threshold may be exceeded, as U.S. EPA does in its regulation. Twelve mmBtu/hr is 40 percent of the U.S. EPA threshold of 30 mmBtu/hr, just as 10,000 metric tons of CO_2e is 40 percent of 25,000 metric tons of CO_2e. A facility with stationary combustions must meet both thresholds to be subject to the regulation.

Summary of Section 95101(b)(2).
This provision indicates that biomass-derived CO_2 must be counted in assessing whether the reporting threshold has been met.

Rational for Section 95101(b)(2).
This provision is needed to ensure that facilities with significant biomass emissions are included in the reporting program. Biomass fuels are a large and growing portion of fuels used in California, and it is important that growth in their use be monitored, both to assess the effects of the cap-and-trade program on the use of biomass resources and to comply with AB 32 requirements to account for emissions from all electricity consumed in California.

Summary of Section 95101(b)(3).
This provision indicates that geothermal and hydrogen fuel cell emissions are counted in assessing whether the reporting threshold has been met. Both CO_2 and CH_4 count for geothermal sources, and CO_2 counts for hydrogen fuel cells.

Rational for Section 95101(b)(3).
This provision is needed to comply with AB 32 requirements to account for emissions from all electricity consumed in California.

Summary of Section 95101(c), Fuel and CO_2 Suppliers.
This provision specifically identifies which fuel and CO_2 suppliers are subject to reporting under the regulation.

Rationale for Section 95101(c).
This provision is needed to establish the threshold for GHG reporting for fuel and CO_2 suppliers subject to a threshold under the terms of the federal regulation. In some cases, a threshold of 10,000 metric tons of CO_2e is established because of the need to monitor compliance with the cap-and-trade rule and to monitor emissions leakage below the cap-and-trade applicability threshold of 25,000 metric tons of CO_2e. The provision is also needed to indicate how a reporting entity subject to a reporting threshold will determine whether its emissions exceed the threshold, including which types of emissions to count in assessing whether the threshold is exceeded.

Summary for Section 95101(c)(1).
This provision requires position holders and refineries that supply a volume of fossil and/or biomass-derived fuel that when combusted would result in greater than or equal to 10,000 metric tons of CO_2e to report.

Rationale for Section 95101(c)(1).
This provision is necessary for position holders and refineries to provide information on fuel supplied to support the determination of their compliance obligations under the ARB cap-and-trade program. Position holders were chosen as the point of regulation for the majority of fuel supplied in California because they are the only entities that can accurately account for the final destination of the fuel. Refineries as specified in section 95121 of the MRR only report fuel supplied to entities not licensed by the California Board of Equalization (BOE), to give a complete account for all fuel combusted in California. Position holders and refineries already report this information to the BOE.

Summary for Section 95101(c)(2).
This provision requires enterers that supply a volume of fossil and/or biomass-derived fuel that when combusted would result in greater than or equal to 10,000 metric tons of CO_2e to report.

Rationale for Section 95101(c)(2).
This provision is necessary to include enterers above the reporting threshold in the reporting requirements, so that they can provide information on fuel supplied to support the determination of their compliance obligations under the ARB cap-and-trade program. Enterers were chosen as a point of regulation because they import fuel into California, and the U.S. EPA MRR does not include domestic imports. Enterers already report this information to the BOE.

Summary for Section 95101(c)(3).
This provision requires producers of biomass-derived fuels that supply a volume of fossil and/or biomass-derived fuel that when combusted would result in greater than or equal to 10,000 metric tons of CO_2e to report.

Rationale for Section 95101(c)(3).
This provision is necessary to track the growth in usage of biomass-derived fuels, to allow ARB to monitor the success of reduction strategies, and to ensure rigorous and constant emissions accounting.

Summary for Section 95101(c)(4).
This provision requires refiners that produce liquefied petroleum gas, without regard to the volume produced, to report.

Rationale for Section 95101(c)(4).
This provision is necessary to include refiners in the reporting requirements for liquefied petroleum gas. Information on liquefied petroleum gas supplied will support the

determination of their compliance obligations under the ARB cap-and-trade program. Refiners already report the majority of the information required to the U.S. EPA MRR, and have no reporting threshold under the U.S. EPA MRR.

Summary for Section 95101(c)(5).
This provision requires operators of interstate pipelines that deliver a volume of fossil and/or biomass-derived fuel that when combusted would result in greater than or equal to 10,000 metric tons of CO_2e to report.

Rationale for Section 95101(c)(5).
This provision is necessary to track fuel deliveries from interstate pipelines, to get an accurate accounting of all natural gas consumed in the state.

Summary for Section 95101(c)(6).
This provision requires California consignees of liquefied petroleum gas that deliver a volume of liquefied petroleum gas that when combusted would result in greater than or equal to 10,000 metric tons of CO_2e to report.

Rationale for Section 95101(c)(6).
This provision is necessary to include consignees of liquefied petroleum gas in the reporting requirements, so that they will provide information on liquefied petroleum gas supplied to support the determination of their compliance obligations under the ARB cap-and-trade program. Consignees were chosen as a point of regulation because they import fuel into California, and the U.S. EPA MRR does not include domestic imports.

Summary for Section 95101(c)(7).
This provision requires local distribution companies that deliver a volume of fossil and/or biomass-derived fuel that when combusted would result in greater than or equal to 10,000 metric tons of CO_2e to report.

Rationale for Section 95101(c)(7).
This provision is necessary to include local distribution companies (LDC) in the reporting requirements, so that they will provide information on natural gas supplied to support the determination of their compliance obligation under the ARB cap-and-trade program. LDCs above the U.S. EPA threshold report almost the same data under the U.S. EPA MRR.

Summary for Section 95101(c)(8).
This provision requires operators of intrastate pipelines that deliver a volume of fossil and/or biomass-derived fuel that when combusted would result in greater than or equal to 10,000 metric tons of CO_2e to report.

Rationale for Section 95101(c)(8).
This provision is necessary to include intrastate pipelines in the reporting requirements, to provide information on natural gas supplied to support the determination of their

compliance obligation under the ARB cap-and-trade program. It is also necessary to give a complete accounting of all natural gas delivered in California.

Summary for Section 95101(c)(9).
This provision requires natural gas liquid fractionators that produce liquefied petroleum gas, without regard to the volume produced, to report.

Rationale for Section 95191(c)(9).
This provision is necessary to include natural gas liquid fractionators in the reporting requirements, so that they will provide information on liquefied petroleum gas supplied to support the determination of their compliance obligations under the ARB cap-and-trade program. Natural gas liquid fractionators already report the majority of the information required to the U.S. EPA MRR.

Summary for Section 95101(c)(10).
This provision requires producers of carbon dioxide to report under the regulation without regard to the volume produced. It also requires importers of carbon dioxide to report if annual imports into California are 10,000 metric tons or more.

Rationale for Section 95101(c)(10).
This provision is necessary to include CO_2 producers and importers in the reporting requirements, so that they will provide information on liquefied petroleum gas supplied to support the determination of their compliance obligations under the ARB cap-and-trade program. CO_2 producers and importers, above the U.S. EPA threshold, already report the majority of the information required to the U.S. EPA MRR.

Summary of Section 95101(d), Electric Power Entities.
This provision identifies the electric power entities that are subject to reporting under the regulation, including electricity importers and exporters, retail providers, the California Department of Water Resources (DWR), the Western Area Power Administration (WAPA), and Bonneville Power Administration (BPA).

Rationale for Section 95101(d).
This provision is necessary to include certain electric power entities in the reporting requirements, so that they will provide information needed to support the determination of their compliance obligations under the ARB cap-and-trade program.

BPA, as an asset-controlling supplier, would report basic information necessary to support ARB's calculation of a supplier-specific emission factor. Electricity importers, including BPA, need this factor to calculate and report GHG emissions associated with BPA system power imported into California.

Two multi-jurisdictional retail providers would report wholesale purchases, sales, and facility information necessary to support ARB's calculation of their supplier-specific emission factors. Electricity importers need these factors to calculate and report GHG emissions associated with their system power imported into California. Reporting by

electricity exporters, which include retail providers and marketers, is necessary to support the ARB GHG Inventory.

All retail providers, in addition to those who import or export electricity, would report retail sales to support the calculation of free allowances under the ARB cap-and-trade program. Reporting by WAPA and DWR of electricity consumed to operate federal and state water projects (pump loads) is necessary to support Scoping Plan Implementation measures for water efficiency and conservation.

Summary of Section 95101(e), Petroleum and Natural Gas Systems.
This provision specifies a reporting requirement for operators of petroleum and natural gas systems and identifies facility types within this sector where reporting is required.

Rationale for Section 95101(e).
Previously, petroleum and natural gas system operators were only required to report stationary combustion emissions. This revised draft regulation adds requirements for the reporting of vented, process, and fugitive emissions – these additional emissions represent a large fraction of facility total emissions for the source categories covered here. U.S. EPA (USEPA TSD W 2009) estimates indicate that process emissions for the petroleum and natural gas system source categories covered by this rule represent approximately 70% to 100% of total source emissions.

Summary of Section 95101(e)(1), Offshore Facilities.
This provision sets forth reporting requirements for offshore petroleum and natural gas production facilities.

Rationale for Section 95101(e)(1).
This provision is necessary because process, vented and fugitive emissions represent a large and major fraction of GHG emissions for this sector (90%, USEPA TSD W 2009) and the current MRR does not provide methodologies to quantify these emissions. Only stationary combustion emissions are covered by the current reporting regulation.

Summary of Section 95101(e)(2), Onshore Facilities.
This provision sets forth reporting requirements for onshore petroleum and natural gas production facilities.

Rationale for Section 95101(e)(2).
This provision is necessary because process, vented and fugitive emissions represent a large and major fraction of GHG emissions for this sector (69%, USEPA TSD W 2009) and the current MRR does not provide methodologies to quantify these emissions. Only stationary combustion emissions are covered by the current reporting regulation.

Summary of Section 95101(e)(3), Natural Gas Processing Plants.
This provision sets forth reporting requirements for onshore natural gas processing plants.

Rationale for Section 95101(e)(3).
This provision is necessary because process, vented and fugitive emissions represent a large and major fraction of GHG emissions for this sector (95%, USEPA TSD W 2009) and the current MRR does not provide methodologies to quantify these emissions. Only stationary combustion emissions are covered by the current reporting regulation.

Summary of Section 95101(e)(4), Onshore Natural Gas Compression Facilities.
This provision sets forth reporting requirements for onshore natural gas transmission compression facilities.

Rationale for Section 95101(e)(4).
This provision is necessary because process, vented and fugitive emissions represent a large and major fraction of GHG emissions for this sector (89%, USEPA TSD W 2009) and the current MRR does not provide methodologies to quantify these emissions. Only stationary combustion emissions are covered by the current reporting regulation.

Summary of Section 95101(e)(5), Underground Natural Gas Storage Facilities.
This provision sets forth reporting requirements for underground natural gas storage facilities.

Rationale for Section 95101(e)(5).
This provision is necessary because process, vented and fugitive emissions represent a large and major fraction of GHG emissions for this sector (84%, USEPA TSD W 2009) and the current MRR does not provide methodologies to quantify these emissions. Only stationary combustion emissions are covered by the current reporting regulation.

Summary of Section 95101(e)(6), Liquefied Natural Gas Storage Facilities.
This provision sets forth reporting requirements for liquefied natural gas storage facilities.

Rationale for Section 95101(e)(6).
This provision is necessary because process, vented and fugitive emissions represent a large and major fraction of GHG emissions for this sector (90%, USEPA TSD W 2009) and the current MRR does not provide methodologies to quantify these emissions. Only stationary combustion emissions are covered by the current reporting regulation.

Summary of Section 95101(e)(7), Liquefied Natural Gas Import and Export Facilities.
This provision sets forth reporting requirements for liquefied natural gas import and export facilities.

Rationale for Section 95101(e)(7).
This provision is necessary because process, vented and fugitive emissions comprise essentially all the emissions for this sector (100%, USEPA TSD W 2009) and the current MRR does not provide methodologies to quantify these emissions. These facilities have not been required to report in the past because any associated combustion emissions were well below the reporting threshold.

Summary of Section 95101(e)(8), Liquefied Natural Gas Distribution Facilities.
This provision sets forth reporting requirements for liquefied natural gas distribution facilities.

Rationale for Section 95101(e)(8).
This provision is necessary because process, vented and fugitive emissions comprise essentially all the emissions for this sector (100%, USEPA TSD W 2009) and the current MRR does not provide methodologies to quantify these emissions. These facilities have not been required to report in the past because any associated combustion emissions were well below the reporting threshold.

Summary of Section 95101(f), Exclusions.
This provision describes the components, facilities, and activities that are not subject to reporting under the regulation.

Rationale for Section 95101(f).
This provision is necessary to inform the specified entities that they are not covered by the regulation. Electricity generating facilities such as wind or solar facilities are not subject to reporting (except as specified) because they generally do not emit GHG emissions. Permitted backup or emergency generators and fire suppression equipment does not need to be reported because emissions from these sources are typically very small, and accurate accounting of the fuel used by these activities can be difficult. Generally, portable equipment is excluded because the emissions are typically small, transient, and captured in other parts of the emission inventory data (such as from fuel suppliers). Certain types of schools are excluded because they are generally very small GHG emitters and to avoid a financial burden on local primary and secondary school districts. The current regulation also exempted hospitals from reporting; these are no longer excluded because they often operate cogeneration units.

Summary of Section 95101(g), Demonstration of Nonapplicability.
For those entities that believe they are not subject to reporting, this provision of the regulation provides ARB with the authority to request and receive information needed to support an entity's claim that it is not subject to reporting.

Rationale for Section 95101(g).
This provision is necessary so that ARB may request information needed to ensure compliance with the regulation and confirm whether an entity is or is not subject to the regulation. Without this section, ARB might be limited in its ability to gather information needed to determine reporting applicability for those not obviously subject to reporting.

Summary of Section 95101(h), Cessation of Reporting.
This provision establishes the criteria that must be met for reporters to cease reporting and verification. In general, the proposed regulation follows the U.S. EPA approach for the cessation of reporting. However, because of the lower ARB reporting threshold of 10,000 tons of CO_2e, this provision includes modifications to the U.S. EPA language to

reflect the difference. It also specifies that a report must be filed for the year the shutdown occurred and for the first full year of non-operation. The provision further clarifies that while facilities that have been shutdown for the entire year do not need to be verified, verification is required for prior emissions data reports.

Rationale for Section 95101(h).
This provision is necessary to provide appropriate flexibility to facilities that lower their emissions below applicable thresholds, or shut down entirely. Facilities with emissions lower than applicable thresholds should be able to cease reporting after a period that demonstrates the lower emissions are not temporary. Facilities that shut down should not be responsible for continued reporting after a report that demonstrates emissions are no longer occurring. In the latter case the expense of verification should also be spared. ARB staff are able to confirm that the shutdown occurred by checking with the local air district.

These provisions vary slightly from the current regulation. Part of the variation is due to the change in reporting threshold. In addition, the current regulation did not directly address the results of a shutdown on emissions reporting. The revised regulation addresses this situation more directly.

Summary of Section 95102, Definitions.

This section defines all key terms used within the regulation that may not be in common usage or which may potentially be ambiguous without a regulatory definition.

Rationale for Section 95102.
This section is necessary to ensure that those subject to the regulation are able to understand and interpret the regulation correctly, and to avoid ambiguity and improve compliance with the regulation. We have attempted to include all key terms used in the regulation, including terms in the previously referenced U.S. EPA regulation, which are usually included without modification to support consistent interpretation of the state and federal regulation.

Summary of Section 95103, Greenhouse Gas Reporting Requirements.

This section specifies the overall greenhouse gas emissions reporting requirements for reporting entities, including clarification on what and how to report, and sets forth deadlines for report and verification statement submittal. It also sets forth the frequency of fuel monitoring, the methods for calculating de minimis emissions, calibrating equipment, and clarifies procedures for changes in methodology.

Rationale for Section 95103.
This section is needed to inform reporting entities of common reporting requirements, and to differentiate between reporting requirements for lower-emitting facilities that are outside the cap-and-trade system and those facilities subject to compliance obligations under the cap-and-trade regulation.

Summary of Section 95103(a), Abbreviated Reporting for Facilities with Emissions Below 25,000 Metric Tons of CO_2e.
This provision allows the use of simplified emission estimation methods and reporting requirements for facilities that emit less than 25,000 metric tons of CO_2e per year. The provision also specifically identifies the information that must be reported by facilities that are able to use this section. It also specifies that suppliers and electric power entities cannot use abbreviated reporting.

Rationale for Section 95103(a).
In the regulatory proposal, the threshold for emissions reporting is 10,000 metric tons of CO_2e per year, which is necessary to provide consistency with the threshold accepted by the other Western Climate Initiative jurisdictions. This threshold includes more reporting entities than the baseline threshold applied by the U.S. EPA regulation, which is 25,000 metric tons. To reduce reporting burdens for facilities that are not subject to the U.S. EPA regulation, but which are subject to the ARB regulation due to the lower 10,000 metric ton threshold, we developed simplified reporting requirements. This approach provides data needed to fully monitor the effects of a cap-and-trade program (including emissions leakage to smaller facilities), while greatly simplifying the reporting requirements for smaller facilities not subject to that program. This provision is designed for operators of facilities. Suppliers are not included here because their reporting requirements under the proposed revised regulation are already relatively simple and/or consistent with existing reporting requirements for tax purposes. Electric power entities are not included here because full and complete reports are needed to account for emissions from imports per AB 32 requirements.

Summary of Section 95103(a)(1).
This provision requires reporting of facility name, and identifying and location information.

Rationale for Section 95103(a)(1).
This information is needed to enable ARB staff to properly identify facilities and their locations, and to enable sorting of emissions data by region or air district.

Summary of Section 95103(a)(2).
This provision requires reporting of total emissions for all stationary combustion units on site, which may be determined through any method specified in the U.S. EPA regulation, including simple application of default emission factors. Emissions are reported by GHG.

Rationale for Section 95103(a)(2).
This provision is needed to provide stationary source emissions totals for the facility, and to inform the facility operator that any method available under the U.S. EPA regulation may be used to estimate these emissions.

Summary of Section 95103(a)(3).
This provision requires reporting of process emissions for the facility, if the facility has one of the process emissions types in the U.S. EPA regulation. (This will occur rarely.) The provision indicates that such emissions are to be estimated using any method available for the type of emissions in the U.S. EPA regulation. The provision also clarifies that if a facility has a Continuous Emissions Monitoring System (CEMS) unit (again expected to be rare for these facilities) the process emissions may be combined with combustion emissions, but that fuel use must still be reported.

Rationale for Section 95103(a)(3).
The provision is needed for the unusual circumstance of process emissions occurring at facilities having relatively low stationary combustion emissions, to ensure the full emissions picture is provided for the facility as a point of comparison to the cap-and-trade threshold, and that ARB is able to fully understand any leakage of process emissions from larger to smaller facilities. Fuel use by fuel type is an important surrogate for emissions and a means of easily checking the reported combustion emissions.

Summary of Section 95103(a)(4).
This provision simply requires the reporting of the methods used to calculate emissions.

Rationale for Section 95103(a)(4).
This provision will enable ARB to understand the basis for the emissions estimate.

Summary of Section 95103(a)(5).
This provision requires the process information (e.g., fuel consumption) used to estimate GHG emissions to be reported, and specifies the units for reporting fuel use. Carbon content and high heat values would also be reported if used to calculate emissions.

Rationale for Section 95103(a)(5).
Process information is needed to ensure the emissions estimates provided can be checked for by ARB reasonableness. Carbon content and high heat values will often not apply, as most facilities reporting under this provision are likely to apply default emission factors.

Summary of Section 95103(a)(6).
This provision requires facilities with on-site electricity generation or cogeneration to provide the information specified in section 95112(a)-(b).

Rationale for Section 95103(a)(6).
This provision is needed so that basic information on electricity generation in California can be maintained. The information requested here is readily available to the reporter.

Summary of Section 95103(a)(7).
This provision requires a signed and date certification statement consistent with U.S. EPA requirements.

Rationale for Section 95103(a)(7).
This provision is needed to ensure a designated party is responsible for the reported information.

Summary of Section 95103(b), Abbreviated Reporting Schedule.
This provision clarifies that abbreviated reports must be submitted by June 1 of each calendar year. It also clarifies that revisions to correct errors must be submitted only if errors exceed 5 percent of total CO_2e emissions or if corrected emissions exceed 25,000 metric tons of CO_2e, in which case, full reporting would be required.

Rationale for Section 95103(b).
Abbreviated reports are due June 1 of each calendar year. Typical reports are due on April 1 of each year. This provision is necessary to provide additional time to entities subject to abbreviated reporting to collect necessary records, perform required estimates, and submit their data. Because these facilities are not directly part of the cap-and-trade program, reporting under the April 1 deadline as required by the other facilities is not necessary. The provision also informs reporting entities when revisions to correct errors need to be submitted.

Summary of Section 95103(c), Abbreviated Reporting Record Keeping.
This provision clarifies that records must still be kept by reporters submitting abbreviated reports, and informs them of which records they must keep. It also provides that facilities submitting abbreviated reports do not have to submit a written GHG Monitoring Plan.

Rationale for Section 95103(c).
This provision is necessary to ensure records are kept in place by the reporter for potential follow-up by ARB, particularly if questions arise about the emission for facilities close to the cap-and-trade threshold. The exclusion of a requirement to develop and maintain a GHG monitoring plan is included here to reduce record-keeping costs for these lower-emitting facilities.

Summary of Section 95103(d), Abbreviated Reporting Verification.
This provision specifies that abbreviated reports do not need to be verified by a third party.

Rationale for Section 95103(d).
Because abbreviated reports are not used for cap-and-trade or to establish compliance obligations, the cost of third party verification of the data to ensure accuracy is not justified. This provision is necessary to inform facilities that they do not have verification requirements.

Summary of Section 95103(e), Reporting Deadlines.
This provision specifies deadlines of April 1 and June 1 for annual emissions reporting.

Rationale for Section 95103(e).
This provision is needed to ensure reports are completed when needed by ARB. The April 1 deadline applies to most reporters; it is one day later than the U.S. EPA deadline, which falls on a State holiday. The June 1 deadline applies to electric power entities and abbreviated emission reports, both of which are not tied to the federal reporting obligation. The later date responds to many comments at and following the March 23, 2010 workshop, which asked for a later deadline to enable electricity transactions data to be properly compiled after it becomes available to electric power entities from outside parties. The later deadline for importers responds to many comments at and following the ARB March 23, 2010, workshop discussing the regulatory proposal.

Summary of Section 95103(f), Verification Requirement and Deadlines.
This provision specifies deadlines of September 1 and October 1 for third party verification. It also clarifies that reporting entities are as responsible as verification bodies to ensure verification statements are submitted on time.

Rationale for Section 95103(f).
This provision is necessary to ensure emissions data are verified and available for use in the cap-and-trade program by the dates indicated. A five-month period is provided for verification of facility and supplier reports, and a four-month period is provided for verification of electric power entity reports. Meeting these deadlines will enable information needed for implementation of the cap-and-trade program to be available when needed, but should provide enough time to enable verification procedures to be implemented successfully within an overall six-month period (April through September). The provision is also needed to inform reporting entities that late contracting with verification bodies does not alleviate them of the responsibility of ensuring their verification statement is submitted on time. This is necessary to promote compliance with the regulation and ensure that emissions data is verified in time to support the cap-and-trade program.

Summary of Section 95103(g), Non-Submitted/ Non-Verified Emissions Data Report.
This provision specifies that the Executive Officer will develop an assigned emissions level for a reporting entity if it fails to submit an emissions data report, or fails to receive a positive verification statement or qualified positive verification statement by the applicable deadline.

Rationale for Section 95103(g).
A reporting entity that is a covered entity under the cap-and-trade program must have annual verified emission data reports that form the basis of its obligation in the cap-and-trade program. This provision is necessary to inform reporting entities of the process and the criteria to be used by the Executive Officer to calculate an assigned emissions level on the behalf of a reporting entity when it fails to provide its own verified emissions

estimate in time for cap-and-trade needs. The criteria in section 95131(c)(5) provide a best-available but conservative estimate of the reporting entity's emissions while serving as a deterrent to noncompliance with the regulation.

Summary of Section 95103(h), Reporting in 2012.
This provision gives an option to operators and suppliers who may not have had monitoring equipment and procedures in place in 2011 to meet their specific emissions calculation requirements in 2012. The option would specify that operators and suppliers report 2011 emissions using monitoring and calculation methods that are applicable to them from 40 CFR Part 98 (the U.S. EPA regulation). It also specifies that electric power entities must report 2011 electricity transactions (MWh) and emissions (MT of CO_2e) under the full specifications of this article as applicable in 2012.

Rationale for Section 95103(h).
This provision is necessary to recognize that this regulation's monitoring requirements will not be in effect in 2011. It allows facilities and suppliers, most of whom will be reporting to U.S. EPA beginning in 2011, to use the information that they would be assembling for their federal reports to report to ARB. This will assist them in cases where the proposed revised regulation may have required a higher tier of calculation and different monitoring to support it. The option is not applicable to electric power entities, which would not be relying on such monitoring data for their emissions reports.

Summary of Section 95103(i), Calculation and Reporting of *De Minimis* Emissions.
This provision specifies criteria and requirements for estimation and reporting of emissions that may be claimed as *de minimis*. This provision is similar to requirements in the currently approved ARB GHG reporting regulation, but a new sentence specifies that *de minimis* methods must be consistent with methods used to report the same emissions to U.S. EPA. The provision further states that *de minimis* calculations are subject to review by the verification body, and must be included in the emissions data report as separately identified *de minimis* emissions. It also clarifies that biomass-derived CO_2 may be included in the facility total against which *de minimis* is measured.

Rationale for Section 95103(i).
This provision is needed to provide an appropriate measure of flexibility to monitoring and reporting of very small sources, thereby reducing costs. The *de minimis* thresholds are identical to those in the current ARB regulation, up to 3 percent of facility emissions, not to exceed 20,000 metric tons of CO_2e. The provision to limit *de minimis* methods to those methods otherwise available to the reporter under the U.S. EPA regulation, for sources reported to U.S. EPA, is needed to ensure consistency with reporting to U.S. EPA, and as a check on reasonableness for emissions estimation for the sources that are reported to U.S. EPA. (*De minimis* sources not reported to U.S. EPA may be estimated using a method of the operator's choosing.) The provision requiring review by the verification body is meant to ensure that *de minimis* emissions are estimated appropriately. The provision to count biomass-derived fuels within the emissions total against which the *de minimis* thresholds are compared ensures sufficient opportunity for

de minimis emissions estimation at facilities that consume significant quantities of biomass fuels.

Summary of Section 95103(j), Calculating, Reporting, and Verifying Emissions from Biomass Derived Fuels.
This provision specifies that facilities and fuel suppliers must separately report, by fuel type, all biomass-derived fuel CO_2 emissions. If the fuel type is not specifically identified in section 95852.2 of the cap-and-trade regulation the fuel will automatically have a compliance obligation. If the biomass-derived fuel is identified in 95852.2 then it will need to be verified subject to the requirements in 95131(i). Biomass-derived fuel that is unable to be verified under 95131(i) will need to be re-identified as Other-Biomass Derived Fuel and will be subject to a compliance obligation.

Rationale for Section 95103(j).
This provision is required because the biomass-derived fuels identified in section 95852.2 of the cap-and-trade regulation may not have a compliance obligation. To avoid double counting certain biofuels will automatically have a compliance obligation and we need an easy tracking method to add them into the Cap-and-Trade compliance obligation. Other biomass-derived fuels may avoid a compliance obligation and will require verification to substantiate that all requirements in 95852.2 and 95131(i) are met. If the verifier is unable to verify the biogenic origin and the other requirements listed in 95852.2 and 95131(i) then the fuel will not be exempt from a compliance obligation.

Summary of Section 95103(k), Measurement Accuracy Requirement.
This provision specifies that reporting entities with fossil fuel emissions equal to or greater than 25,000 metric tons of CO_2e and others subject to the cap-and-trade regulation must comply with U.S. EPA calibration requirements of ± 5 percent measurement accuracy for their measurement devices. It also specifies that for entities with frequent outages, they must notify the Executive Officer of any calibration postponement, which would be subject to the approval of the Executive Officer. This notice would include an explanation of the postponement and the date when the calibration would be completed.

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

ensure that ARB is aware of such delays, and if a pattern of delay develops, that the Executive Officer is able to direct that calibrations be carried out.

Summary of Section 95103(l), Weekly Fuel Monitoring.
This provision requires that facility operators monitor fuel measurement equipment and maintain records of its proper operation by recording fuel consumption quantities at least weekly when used for GHG emissions calculations. It also specifies that this monitoring must be part of the GHG Monitoring Plan and that the records of fuel consumption must be sufficient to apply missing data substitution procedures in section 95129 if necessary.

Rationale for Section 95103(l).
This provision is necessary to ensure the proper functioning of monitoring equipment for collection of high quality data and to provide historical data for supporting missing data substitution procedures. Unlike fuel characteristic data, which generally has a range of values by definition, fuel consumption can range anywhere from zero to the maximum potential capacity of the equipment. Therefore, staff believes that missing fuel consumption data must be filled with values that can either be correlated with other measured operational parameters or be based on the actual fuel use values under usual operating conditions.

This provision requires weekly recording of fuel use data (daily data is warranted in some situations, but this would not be required). By recording regularly the amount of fuel consumed, the operator builds a base of data that can be drawn upon if it becomes necessary to substitute for missing data when equipment breaks down. The operator benefits from this active monitoring because the weekly or daily data collected will reduce or eliminate the need for more punitive data substitution in a missing data situation.

Summary of Section 95103(m), Changes in Methodology.
This provision requires, when choices are available, that operators select and retain the same methods year-to-year for reporting emissions data. Different methods can be used following approval by the Executive Officer.

Rationale for Section 95103(m).
This provision is necessary to prevent reporters from choosing different emission calculation methods from year to year, which could intentionally or unintentionally produce distorted or inconsistent consistent GHG data. This would produce uncertainty for cap-and-trade and GHG emission inventory programs, which could reduce the overall confidence in data collected and used by the programs. If a credible and scientifically justifiable argument is made to the Executive Officer for the need to use a different method than that historically used, and the Executive Officer approves the change, then another specified method may be used.

Summary of Section 95103(m)(1), Using Improved Methods.
This provision allows operators to make a permanent change to a higher-tier method to compute emissions.

Rationale for Section 95103(m)(1).
This provision provides an exception so that a permanent change can be made to improve the emissions calculation method without Executive Officer approval. Installation of a CEMS after 2013 is the most likely scenario, and the regulation should not lock in an inferior calculation method.

Summary of Section 95103(m)(2), Temporary Change In Method.
This provision allows operators to temporarily modify their baseline methods, when the modification is needed to acquire data required by the missing data provisions. These missing data provisions (section 95129) come into effect when an operator is unable to collect the information specified in regulation.

Rationale for Section 95103(m)(2).
This provision is necessary because 95103(m) prohibits changes to methods. This provision provides an exception so that a method can temporarily be changed so that other data may be collected, rather than potentially collecting no data at all using the non-functioning method or approach.

Summary of Section 95103(m)(3), Reason for Change.
This provision requires operators to describe why a change in methods is being proposed. The operator must also show the difference in emissions estimates using the existing and proposed method.

Rationale for Section 95103(m)(3).
This provision is required to adequately evaluate the potential benefits and disadvantages of changing methods. The data provided helps the ARB to establish that the proposed change in method is scientifically justified and that it would not artificially alter the emission estimates.

Summary of Section 95103(m)(4), Change at Year End.
This provision encourages operators to change methods only at the start of a new reporting year, and not sometime during the reporting year.

Rationale for Section 95103(m)(4).
This provision is necessary to help prevent the reporting of data using one method for part of the year, and then converting to another method for another part of the year. Using multiple methods through the year would produce inconsistent data and would produce less coherent, more difficult to validate, emission estimates.

Summary of Section 95103(n), Addresses.
This provision provides the mailing address for U.S. mail and package deliveries required by the regulation and substitutes the correct California address for those provided in 40 CFR §98.9.

Rationale for Section 95103(n).
This provision is necessary to inform those entities subject to the regulation of the correct mailing address for items that need to be provided via mail to the ARB. In addition, this address substitutes for the address provided in 40 CFR §98.9, so that items intended for the ARB do not get mailed to the U.S. EPA.

Summary of Section 95104, Emissions Data Report Contents and Mechanism.

Section 95104 of the regulation specifies the primary elements required to be provided in an emissions data report. In general, the requirements mirror those in 40 CFR §98.3(c), with additional qualifications below.

Rationale for Section 95104.
In order to provide for complete and consistent reporting, it is necessary to explicitly specify the contents of data reports and the specific reporting mechanism.

Summary of Section 95104(a), General Contents.
This provision identifies the general contents of an emissions data report, including the items in 40 CFR §98.3(c), ARB identification number, air basin, air district, county and geographic location.

Rationale for Section 95104(a).
This provision is necessary to inform the reporting entity what information needs to be included in the GHG emissions data report. The specified information, both that required by 40 CFR §98.3(c) and in this section, are required to provide unique facility identifying information, emissions information, and other data needed to support both an GHG emission inventory and a cap-and-trade program. If the data was not collected it would not be possible to clearly identify facilities or determine their emissions and other underlying GHG data.

Summary of Section 95104(b), Designated Representative.
This provision specifies that a single point of contact must be identified and provided for GHG reporting.

Rationale for Section 95104(b).
With the previous implementation of the existing ARB regulation for GHG reporting, we allowed an informal self-designation of facility or entity "Managers" who we used as primary contacts for reporting. One of the designated managers would also be responsible for certifying the reported data as accurate and complete. This provision is necessary to improve on this approach and to provide complete transparency and structured accountability by providing a single point of contact for each reporting entity.

These requirements are also based on those of 40 CFR §98.4 and are necessary to harmonize with the U.S. EPA GHG reporting requirements..

Summary of Section 95104(c), Corporate Parent and NAICS Codes.
This provision requires facilities to report their corporate parent and their North American Industry Classification System (NAICS) codes, as required by U.S. EPA in rule amendments promulgated September 22, 2010. Reporters would provide the same information to ARB.

Rationale for Section 95104(c).
This provision is necessary because NAICS codes include critical information needed for classifying industrial sectors and for a variety of cap-and-trade activities such as identifying allowances and benchmarking, and because corporate parent information helps to group and classify reporters as needed for regulatory programs and analysis.

Summary of Section 95104(d), Energy Purchases.
This provision specifies that energy purchase information must be reported, which is beyond the standard U.S. EPA reporting requirements.

Rationale for Section 95104(d).
The requirement to report electricity purchases, steam purchases, and cooling purchases is necessary to formulate a more complete facility GHG emissions footprint for those reporting, to ensure the quality of the reported data, and to potentially reconcile data provided by the user and generator of the energy. It is also needed by ARB to support implementation of the proposed Energy Audits and Co-benefits Regulation.

Summary of Section 95104(e), Reporting Mechanism.
This provision has been maintained from the current ARB GHG reporting regulation and specifies that reporting entities must submit emissions data reports to ARB via the ARB GHG Reporting Tool or another tool approved by the Executive Officer.

Rationale for Section 95104(e).
To ensure orderly and consistent reporting, a common reporting mechanism must be specified for all reporters. This provision is necessary to inform reporting entities how they will submit required reports to ARB.

Summary of Section 95105, Recordkeeping Requirements.

This section describes which records must be maintained by those subject to reporting. The bulk of the recordkeeping requirements are identical to those specified in 40 CFR §98.3(g)-(h) except for the qualifications described below.

Rationale for Section 95105.
This section is necessary to ensure that all reporting entities maintain complete and consistent data records which document measurements, calculations, results, and other

information. The requirements are needed to properly verify reported data, provide a detailed historical record of data and results, and to assist in any auditing or compliance checks of reported data. Rigorous reporting and recordkeeping is a keystone requirement to providing a credible GHG cap-and-trade program.

Summary of Section 95105(a), Duration.
This provision establishes that those with a compliance obligation under the cap-and-trade regulation must maintain records for 10 years. It also requires that those entities who are subject to the proposed ARB reporting regulation, but who do not have a compliance obligation under the cap-and-trade regulation, maintain records for five years.

Rationale for Section 95105(a).
This provision is necessary to clarify how long reporting entities must keep and maintain records. It also ensures that records are maintained for a sufficient period of time so that ARB may verify and audit the records if necessary.

Summary of Section 95105(b), ARB Requests for Records.
This provision clarifies that ARB reporting entities must provide records or other materials that are required for complying with this regulation to ARB within 20 days of a request by ARB.

Rationale for Section 95105(b).
This provision is necessary to ensure compliance with the regulation. In order to provide a proper auditing function, ARB must have timely access to the underlying information that was used to generate emissions estimates or other required data.

Summary of Section 95105(c), GHG Monitoring Plan.
This provision requires that operators complete and maintain a GHG Monitoring Plan which includes key information needed to document and validate reported data. Monitoring plans are only required by those subject to the cap-and-trade regulation, in addition to those who are required to report to U.S. EPA. The monitoring plan must meet the requirements for such plans in the U.S. EPA regulation, and some additional specific requirements listed in this provision.

Rationale for Section 95105(c).
This provision is needed to provide specific direction to operators regarding what information must be collected and maintained in a GHG Monitoring plan, as described below. To reduce costs and complexity, operators not subject to the cap-and-trade regulation or not reporting to U.S. EPA are not required to develop a GHG Monitoring Plan. These operators are excluded from the requirement because it is less critical to have the additional detailed documentation for operators not in a market-based GHG trading system.

Summary of Section 95105(c)(1), Fuel Use Measurement Devices.
This provision requires operators to identify fuel use measurement devices, indicate how they are used in the emissions data report, and include the information in the written GHG Monitoring Plan.

Rationale for Section 95105(c)(1).
This provision is required because fuel use measurement data is one of the primary cornerstones of computing GHG emissions data. If the fuel devices are not clearly identified and their use specified, then the accuracy and completeness of any emissions data could be uncertain.

Summary of Section 95105(c)(2), OEM Documentation.
This provision requires operators to obtain original equipment manufacturer (OEM) or other documentation that specified accuracy, calibration, and calibration data for measurement devices, and include the information in the written GHG Monitoring Plan.

Rationale for Section 95105(c)(2).
This provision is provided so that when GHG data reports are being audited or verified, the specifications for measurement devices are available and included in the GHG Monitoring Plan. Comparison of these specifications against what was actually used or done by the operator helps to confirm the accuracy of the reported data, and compliance with the regulation.

Summary of Section 95105(c)(3), Training.
This provision requires operators to maintain records of training practices, procedures, and materials, and to include this information in the GHG Monitoring Plan.

Rationale for Section 95105(c)(3).
This provision is provided so the ARB and verifiers can use information to help confirm that those subject to reporting have obtained the necessary training and expertise to competently meet the requirements of the regulation.

Summary of Section 95105(c)(4), Fuel Analysis Methodologies.
This provision requires operators to retain the detailed methodologies for fuel analysis used in complying with the regulation, and include these methods in the GHG Monitoring Plan.

Rationale for Section 95105(c)(4).
This provision is required because the methodologies used for fuel analysis are critical to the accuracy of GHG emission estimates. Use of incorrect methodologies can significantly alter emissions, so requiring that the methods be included in the GHG Monitoring Plan provides a mechanism to help confirm that the correct methods were used.

Summary of Section 95106, Confidentiality.

Summary of section 95106(a).
This provision establishes that emissions data submitted to ARB pursuant to the proposed regulation is public information. It also establishes that data reported to the U.S. EPA pursuant to the reporting requirements of the U.S. EPA reporting rule (USEPA MRR 2009) which is considered by U.S. EPA to be non-confidential shall also be treated as public information by ARB.

Rationale for section 95106(a).
This provision is necessary to inform the public of what information is public information and what is confidential. In addition, given that any information released publicly by U.S. EPA would necessarily become public information, this provision is also necessary to provide consistency with the U.S. EPA reporting rule (USEPA MRR 2009).

Summary of section 95106(b).
This provision establishes that information submitted to ARB pursuant to the proposed regulation that does not qualify as emissions data under section 95106(a) may be designated as confidential if it is either a trade secret or otherwise exempt from public disclosure under the California Public Records Act (Government Code section 6250 et seq.), and such requests for confidentiality will be evaluated by ARB in accordance with the procedures of title 17, CCR, sections 91000 to 91022. The proposed regulation does not change the existing language of this provision.

Rationale for section 95106(b).
This provision is necessary to inform the public how information may be designated as confidential and how ARB will assess such designations pursuant to California law.

Summary of Section 95107. Enforcement.

This section proposes the penalties and consequences of not complying with these regulations. These provisions include penalties pursuant to Health & Safety Code (H&SC) section 38580.

Summary of section 95107(a).
This provision establishes that the failure to submit a required report, including a verification statement, emissions data report, or other record, or the submittal of a late, incomplete, or inaccurate report is considered a separate violation for each day or portion thereof that the report remains unsubmitted, incomplete, or inaccurate.

Rationale for section 95107(a).
This provision provides clarification as to the basis, processes and procedures that would apply in an enforcement proceeding. It is necessary to ensure compliance with the regulation and to deter the submission of incomplete or inaccurate reports, as well as to ensure the correction of mistakes as soon as possible. The section also clarifies that "inaccurate" relates to the level of reproducibility of a test or measurement method.

This provision also greatly revises the currently adopted version of section 95107(a) (ARB MRR 2007), which included the "knowing submission of false information, with intent to deceive" as a separate violation. This revision replaces the "knowing, with intent to deceive" standard of liability with a strict liability standard and is necessary to align with WCI requirements and with other ARB environmental regulations. As noted by the WCI in its *Response to Stakeholder Comments and Final Draft Essential Requirements for Mandatory Reporting* (WCI Response to Comments 2009, page 15), strict liability is the normal standard for the imposition of civil liability in environmental regulatory programs. In fact, AB 32's enforcement provisions expressly incorporate existing strict liability enforcement statutes such as H&SC sections 42400 and 42402 without any statutory language indicating an intent to require a higher, narrower standard of 'knowing' or 'intent to deceive' in every instance. Other ARB environmental regulations, including the Low Carbon Fuel Standard (Title 17, CCR, section 95484(e)) and the Airborne Toxic Control Measure for Auxiliary Diesel Engines Operated on Ocean-Going Vessels At-Berth in a California Port (Title 17, CCR, section 93118.3(h)), use the normal strict liability standard. Stakeholders have raised the same concerns addressed in the WCI Response to Comments 2009 with ARB. In order to ensure consistent enforcement with other ARB environmental regulations, and in accordance with the WCI, this provision has replaced the "knowing submission of false information, with intent to deceive" standard of liability with a strict liability standard.

Summary of section 95107(b).
This provision establishes that each day, or portion thereof, a regulated party does not comply with a requirement of the proposed regulation is considered a separate violation.

Rationale for section 95107(b).
This provision provides clarification as to the basis, processes and procedures that would apply in an enforcement proceeding. It is authorized by H&SC section 38580(b)(3) and is necessary in this instance to ensure compliance with the regulation, as well as to encourage the correction of mistakes as soon as possible. This provision is also necessary to provide consistency with 40 C.F.R. §98.8 (U.S. EPA MRR 2009). This provision revises the currently adopted version of section 95107(b) (ARB MRR 2007). The requirements of the currently adopted version of section 95107(b) are now included in the revised section 95107(a) as described above.

Summary of section 95107(c).
This provision specifies that where a regulated party fails to report the metric tons of carbon dioxide equivalent (CO_2e) in its emissions data report as required by the regulation, each metric ton of CO_2e emitted but not reported is a separate violation.

Rationale for section 95107(c).
This provision provides clarification as to the basis, processes and procedures that would apply in an enforcement proceeding. The proposed revisions are necessary to ensure accurate and stringent emissions data in order to support a cap-and-trade program, and this violation is designed to ensure that reporting entities accurately report

their GHG emissions to ARB and that the number of violations directly reflects the amount of CO_2e emissions. A metric ton was selected as the essential unit of violation for unreported emissions because metric tons are the basic unit both for reporting emissions and for allocations under the proposed cap-and-trade regulation. By using metric tons, the number of violations will remain proportional to emissions, which is in keeping with the statute's overall intent to reduce emissions. In addition, existing enforcement statutes direct ARB to consider, when determining administrative penalties, the "extent of harm caused by the violation," and the "nature and persistence of the violation." (H&SC sections 42410(f) and 42403.5((b)(1)(2)). This provision makes specific that the "extent of harm" and the "nature" of a failure to report will be analyzed, for penalty purposes, in terms of metric tons. This provision is also consistent with similar violations in the proposed cap-and-trade regulation, as well as the proposed Renewable Electricity Standard regulation (*see* proposed Title 17, CCR, section 97009).

Summary of section 95107(d).
This provision specifies that each failure to comply with the methods in the proposed regulation for measuring, collecting, recording, and preserving information needed for the calculation of emissions constitutes a separate violation of the proposed regulation.

Rationale for section 95107(d).
This provision provides clarification as to the basis, processes and procedures that would apply in an enforcement proceeding. This provision is necessary to inform the public what constitutes a violation of the proposed regulation, and to ensure that reporting entities will utilize the methods required by the regulation. This provision is also necessary to provide consistency with 40 C.F.R. §98.8 (U.S. EPA MRR 2009).

Summary of section 95107(e).
This provision proposes the revocation or modification of an Executive Order issued pursuant to the proposed regulation as one consequence of violating the proposed regulation.

Rationale for section 95107(e).
This provision provides clarification as to the basis, processes and procedures that would apply in an enforcement proceeding. This provision is necessary to inform the public of what constitutes a sanction for noncompliance with the regulation.

Summary of section 95107(f).
This provision clarifies that the violation of any condition of an Executive Order issued pursuant to the proposed regulation constitutes a separate violation of the proposed regulation.

Rationale for section 95107(f).
This provision provides clarification as to the basis, processes and procedures that would apply in an enforcement proceeding. This provision is necessary to inform the public of what constitutes a violation of the proposed regulation.

Summary of section 95107(g).
This provision merely restates existing law regarding penalties.

Rationale for section 95107(g).
This provision provides clarification as to the basis, processes and procedures that would apply in an enforcement proceeding. This provision is necessary to inform the public of what the penalties will be for noncompliance with the regulation and to direct the public to the appropriate statute to determine the penalties.

Summary of section 95107(h).
This provision merely restates existing law regarding injunctions.

Rationale for section 95107(h).
This provision provides clarification as to the basis, processes and procedures that would apply in an enforcement proceeding. This provision is necessary to inform the public of what the penalties will be for noncompliance with the regulation and to direct the public to the appropriate statute regarding injunctions.

Summary of Section 95108, Severability.

Summary of Section 95108.
This section ensures that if one provision of the regulations is declared invalid by a court or other authority, the remaining provisions will remain in full force and effect.

Rationale for Section 95108.
This section is necessary to ensure that if ARB has enacted a provision in the proposed regulatory article that is illegal or unconstitutional, the remaining regulatory provisions remain intact.

Summary of Section 95109, Standardized Methods.

Summary of Section 95109(a).
This provision requires entities to use either those standardized methods and materials listed in the U.S. EPA regulation, or another similar method published by an organization listed in 40 CFR §98.7 that is appropriate to the analysis being conducted. The section also provides the option for the characteristics of gaseous fuels to be determined using chromatographic analysis as specified in the U.S. EPA rule. The section also requires all methods used to be documented in the GHG Monitoring Plan that is as required by section 95105(c).

Rationale for Section 95109(a).
This provision is necessary to provide requirements to reporters on the appropriate laboratory methods to be used in determining emissions. It provides limited flexibility to reporters to use methods beyond those specified by U.S. EPA, which will enable regularly updated laboratory methods to be used. The provision that allows gas chromatography to determine fuel characteristics is needed to provide consistency with

specific U.S. EPA requirements. The provision to require that methods be documented in the GHG Monitoring Plan is needed to ensure the verification body can check that appropriate methods were used for the analyses being conducted. The requirements here vary from the very specific and limited requirements in the current regulation, in recognition of the fact that laboratory methods change and reporters need the flexibility to adapt their emissions calculations to such changes.

Summary of Section 95109(b).
This provision allows alternative test methods to those in 95109(a) to be used upon written approval by the Executive Officer based on a demonstration to the satisfaction of the Executive Officer that the alternative methods are equally or more accurate than the methods in 95109(a).

Rationale for Section 95109(b).
This provision will allow reporting entities the option to request approval of alternative test methods that may work more effectively at some individual facilities, based on site-specific situations, or may be more generally usable at a wide range of facilities. Requiring written approval of alternative test methods by the Executive Officer is necessary to ensure that such alternative test methods will provide accurate data.

Subarticle 2
Reporting Requirements and Calculation Methods for Specific Types of Facilities, Suppliers, and Entities

Summary of Section 95110, Cement Production.

This provision specifies the overall greenhouse gas emissions reporting requirements and methods for the cement production industry.

Rationale for Section 95110.
This provision is necessary because these facilities within California can produce significant levels of greenhouse gas emissions. In order to accurately quantify their greenhouse gas emissions it is necessary to fully specify reporting requirements for the cement production sector. The proposed regulation provides consistent and equitable reporting requirements and supports the proposed cap-and-trade program. In addition, this provision substantially harmonizes most ARB reporting requirements with U.S. EPA greenhouse reporting requirements for the sector, which helps to simplify reporting for those subject to the regulation.

Summary of Section 95110(a), CO_2 from Fossil Fuel Combustion.
This provision of the regulation provides specific requirements for estimating CO_2 emissions for the industrial sector.

Rationale for Section 95110(a).
This provision is necessary because it requires facilities subject to this section to apply calculation methods that account for fuel carbon variability, which provides data of

sufficient quality for the cap-and-trade program and consistent with proposed WCI Harmonization Requirements. The requirement also allows the use of Tier 1 estimation methods for de minimis sources and standardized fuels, which helps to simplify the reporting requirements where warranted.

Summary of Section 95110(b), Monitoring, Data, and Records.
This provision requires that monitoring, data, records, and other information collected or reported is consistent with the provisions of the CO_2 combustion method(s) used by the operator in the previous section.

Rationale for Section 95110(b).
This provision is necessary to ensure complete, accurate, and credible GHG emissions data. This requirement for data collection and reporting helps to identify any data errors and greatly assists with the verification of GHG emissions data reports for accuracy and completeness.

Summary of Section 95110(c), Procedures for Missing Data.
This provision specifies the procedures for the substitution of missing data for this industrial sector.

Rationale for Section 95110(c).
This provision is necessary because a primary goal of the reporting program is to collect accurate GHG emissions data in support of cap-and-trade. This helps to ensure that the emissions are not underestimated for the facility, and also makes it unfavorable for reporting entities to attempt to report using incomplete or false data.

Summary of Section 95110(c)(1), Procedures for Missing Data - Stationary Combustion and CEMS.
This provision identifies the missing data provisions in the regulation that must be followed for stationary combustion sources, and sources using CEMS. The provision refers to section 95129 of the regulation, which specifies these requirements for all combustion and CEMS sources.

Rationale for Section 95110(c)(1).
This provision is needed to specify how to substitute for missing data for combustion sources or sources using CEMS, consistent with similar provisions applied in the requirements for other industrial sectors. Without this provision, missing data provisions would be ambiguous or unclear to the reporting entity. The specific provisions of section 95129 are addressed in the summary and rationale paragraphs for that section.

Summary of Section 95110(c)(2), Procedures for Missing Data – Carbonate Content of Clinker and Cement Kiln Dust.
This provision applies missing data procedures for instances when clinker and cement kiln dust carbonate content data are missing and a new analysis cannot be undertaken. The provision requires use of maximum data values if less than 80% of required data are available or use of the highest quality assured value recorded during the given data

year, as well as the two previous data years if more than 80% but less than 90% of required data are available.

Rationale for Section 95110(c)(2).
This provision is necessary to provide direction to reporting entities about what to do if they are missing required data for clinker and cement kiln dust carbonate content. If this provision was not included, then inconsistent or inaccurate reporting would likely result. In addition, the provision helps to encourage compliance, provides a strong incentive to maintain accurate and operational measurement systems, and encourages reporting entities to follow a robust sampling regime that includes backup sample collection.

Summary of Section 95110(c)(3),Procedures for Missing Data – Raw Material Consumption and Clinker Produced.
This provision describes what an operator is required to do when data are missing for raw material consumption or clinker production. The provision requires use of maximum data values if less than 80% of required data are available.

Rationale for Section 95110(c)(3).
This provision is necessary to provide direction to operators about what to do if they are missing required data for raw material consumption or clinker production. If this provision was not included, then inconsistent or inaccurate reporting would likely result. In addition, the provision helps to encourage compliance and provides a strong incentive to maintain accurate and operational measurement systems.

Summary of Section 95110(c)(4), Procedures for Missing Data - Recordkeeping.
This provision requires operators to document the procedures used for estimates performed using missing data.

Rationale for Section 95110(c)(4).
This provision is necessary to ensure that required calculations are well documented so that the methods used, and the validity and accuracy of those methods, can be confirmed in the verification process.

Summary of Section 95110(d), Additional Data to Support Benchmarking.
This provision requires the reporting of additional data parameters to support benchmarking activities.

Rationale for Section 95110(d).
This provision is needed to allow ARB to collect and calculate data that will serve as the foundation for benchmarking activities. Benchmarking, as part of a cap-and-trade system, helps to protect trade-exposed industries from certain competitive disadvantages. Benchmarking also gives greater value to the most efficient entities, and rewards early actions to reduce emissions.

Summary of Section 95111, Electric Power Entities.

This section specifies the greenhouse gas emissions reporting requirements and additional required information for the following for electric power entities:

- Retail providers and electricity marketers (including WAPA, BPA, DWR, and multi-jurisdictional retail providers) provide information on imported electricity—electricity deliveries and associated emissions.
- BPA, as an asset-controlling supplier, has the option to provide additional information on a voluntary basis.
- Multi-jurisdictional retail providers report wholesale purchases, sales, and facility information.
- Procedures are specified for ARB to calculate emission factors for specified facilities and units associated with imported electricity.
- The default emission factor for electricity from unspecified sources is provided.
- Provisions account for real emissions reductions and assure that reductions from changes in specified resources are real.
- Information is provided by electricity importers for ARB to report those emissions reductions attributable to electricity consumed in California but that do not also reduce net emissions in the total Western Region bulk system power pool.
- Exported electricity is reported by retail providers and marketers.
- Retail providers report retail sales. Verification of retail sales is not necessary if the information is deemed not confidential.
- WAPA and DWR report electricity consumed to operate Federal and State water projects (pump loads), respectively.

Rationale for Section 95111.
Greenhouse gas emissions attributed to electricity consumed in California are nearly equally divided between in-state generation and imported electricity. Imported electricity accounted for 61 million metric tons of CO_2e, slightly more than the estimated 55 million metric tons of CO_2e from in-state electricity generation, as published in the *2008 ARB GHG Inventory* updated May 12, 2010 (ARB CA GHG Inventory for 2000-2008). This reality of the California electricity sector requires imported electricity to be treated similarly to in-state generation.

Of the total greenhouse gas emissions associated with imported electricity, 43 percent was attributed to facilities outside California that are under contract or ownership obligation to serve California customers, referred to as specified sources. The remaining 57 percent was attributed to unspecified sources that contribute to the Western Region power pool. Conditions for reporting specified sources of electricity are necessary to support California's cap-and-trade program and fundamental to assuring the environmental integrity of the cap.

The electricity sector has unique characteristics that are reflected in the staff proposal. The staff proposal is consistent with AB 32 requirements, the current ARB regulation

(ARB MRR 2007), the proposed electricity sector protocol recommended jointly by the California Public Utilities Commission (CPUC) and the California Energy Commission (CEC) included as attachment D in the 2007 staff report (ARB ISOR 2007), and the Western Climate Initiative (WCI) *Final Essential Requirements of Mandatory Reporting* (WCI ERMR 2009). Staff's proposal incorporates the requirement in AB 32 and the WCI Partner jurisdictions' recommendation that emissions from electricity generated outside the WCI Partner jurisdictions but consumed within them be included in the program (WCI Program Design 2010).

Retail providers and electricity marketers—including WAPA, BPA, DWR, and multi-jurisdictional retail providers—are required to provide information on imported electricity to support the determination of their compliance obligations under the ARB Cap-and-Trade program. BPA, as an asset-controlling supplier, may voluntarily report additional information necessary to support ARB's calculation of a more precise supplier-specific emission factor. Electricity importers, including BPA, need this factor to calculate and report GHG emissions associated with BPA system power imported into California. PacifiCorp and Sierra Pacific Power Company are the two multi-jurisdictional retail providers in California. They report wholesale purchases, sales, and facility information necessary to support ARB's calculation of their supplier-specific emission factors. Electricity importers, including PacifiCorp and Sierra Pacific Power Company, need these factors to calculate and report GHG emissions associated with their system power imported into California.

The reporting of exported electricity by electricity exporters, which include retail providers and marketers, is needed to support the ARB GHG Inventory. All retail providers, in addition to those who import or export electricity, report retail sales to support the calculation of free allowances under the ARB cap-and-trade program. WAPA and DWR report electricity consumed to operate Federal and State water projects (pump loads), respectively, to support Scoping Plan Implementation measures for water efficiency and conservation.

Summary of Section 95111(a), General Requirements and Content for GHG Emissions Data Reports for Electricity Importers and Exporters.

The list of required elements for electric power entity greenhouse gas (GHG) reports is provided in subsection 95111(a). Emissions, in metric tons of CO_2e, are to be reported in addition to the continuing requirement to report electricity deliveries in megawatt-hours. Electricity importers and exporters must report deliveries and associated GHG emissions from imported electricity from unspecified and specified sources, imported electricity from asset-controlling suppliers and multi-jurisdictional retail providers, exported electricity, and electricity from generating and cogeneration units in California. Provisions for reporting electricity wheeled through California, electricity deliveries under exchange agreements, and electricity generating and cogeneration units outside of California are included in section 95111(a). Documentation requirements to support verification also are included.

Rationale for Section 95111(a).
This provision is necessary to meet the statutory mandate of AB 32, which requires the reporting of all electricity generated and consumed in California. Electric power entities report GHG emissions associated with imported electricity to determine the quantity of allowances each must hold for compliance with the ARB cap-and-trade program. Electricity deliveries are the basis for the emissions calculations and are reported to support independent verification, auditing and enforcement by the ARB, statewide data quality assurance by the ARB in collaboration with the CEC and CPUC, and the ARB GHG inventory.

Exported electricity is reported for information purposes only. In 2008 and 2009, reported exports were a very small portion of reported imports, only two to three percent. It is anticipated that as ARB links with other WCI jurisdictions, this information will be needed for regional tracking and data quality assurance. Exports are not reported to calculate cap-and-trade compliance obligations nor free allocations. The concept of an optional border adjustment or free allocations for exports has been discussed by the WCI Electricity Committee.

Exchange agreements are reported consistent with requirements to report imported and exported electricity. ARB has determined that netting is not allowed, since imported electricity is consumed in California and exported electricity is first generated from California sources. Imported electricity is reported to determine the compliance obligation. Electricity generated in California and exported must also pay its cap-and-trade compliance obligation, so that future linked jurisdictions can be assured that electricity exported from California has met its compliance obligation. Electricity cannot pass through California without paying its compliance obligation unless it is wheeled through California. This means the electricity does not have a final point of delivery in California, i.e., it does not sink or serve load in California. Allowing netting of imports and exports for exchange agreements would have the affect of allowing electricity that is consumed and generated in California to avoid its compliance obligation, which is counter to the requirements of AB 32.

Electricity importers and exporters report electricity wheeled through California as a data quality assurance measure.

Summary of Section 95111(b), Calculating GHG Emissions.
Required methods for calculating GHG emissions associated with imported electricity are provided in section 95111(b) and divided into four types of sources:

1. unspecified sources
2. specified facilities or units
3. specified asset-controlling suppliers
4. specified multi-jurisdictional retail providers.

Electric power entities will use the equations provided in this provision, which include ARB emission factors. ARB will calculate and publish on its Mandatory Reporting Program website the needed emission factors for each of the four types of sources for

use by reporting entities. ARB will calculate the emission factors based on a preferred ranking of data sources described in each subsection. ARB will publish and update these emission factors prior to the reporting deadline.

Rationale for Section 95111(b).
This provision is necessary to calculate and report associated GHG emissions (MT of CO_2e) for imported electricity (MWh) consumed in California, including line losses, as required by AB 32. A two percent transmission loss factor is established to meet the requirement in AB 32 to include line losses when they are not already included in reported deliveries or made up from generation sources located in California. ARB will calculate and publish the needed emission factors in order to assure rigorous and consistent accounting. To provide transparency, it is necessary to demonstrate how ARB will calculate the needed emission factors.

Summary of Section 95111(b)(1), Calculating GHG Emissions from Unspecified Sources.
This provision sets forth the methods for calculating GHG emissions associated with unspecified sources of imported electricity.

Rationale for Section 95111(b)(1).
This provision is necessary for electric power entities to report GHG emissions associated with electricity from unspecified sources. This provision is based on coordinated efforts by ARB, CEC, CPUC, and the WCI. These efforts and the reasoning behind them are explained below.

The default emission factor for electricity from unspecified sources will be re-calculated using the Final WCI Default Emission Factor Calculator created by CPUC staff, vetted through the WCI Electricity Team, and adopted by the WCI Partners (WCI Default Emission Factor Calculator 2010). Based on an interim prototype version of the WCI calculator, ARB staff is currently proposing a default emission factor equal to the average emission factor for years 2006, 2007, and 2008. Marginal facility capacity factors are less than 60 percent and 2 percent transmission line losses are included. The resulting default emission factor is 0.435 MT of CO_2e/MWh. This factor is needed for calculating a compliance obligation during the first compliance period on imported electricity reported under section 95111 and for setting the cap under the cap-and-trade program.

It is anticipated that ARB, in future rulemakings, will reset this emission factor for reporting purposes before each compliance period, based on a rolling three year average. This procedure will accommodate the interests of stakeholders to smooth out variations from year to year and have a factor in advance of each compliance period. Stakeholders also have recommended that the default factor should be updated periodically, so reported emissions reflect cleaner emitting marginal generation over time.

The WCI Electricity Team has posted two versions of the default emission factor calculator on the WCI website. The "lite" version contains the calculator worksheet and its data table. The full version contains the underlying data that were used to create the data table for the calculator, and an embedded document from the original Energy Information Administration files that provides additional information on the data and the codes used to identify fuels and generation technologies.

For electricity that can not be traced back to specified sources, the CPUC and CEC recommended that ARB use the default emission factor of 1,100lbs CO_2/MWh, until a regional tracking system could be developed (ARB ISOR 2007 - Attachment D). The joint recommendation explains that 1,100lbs CO_2/MWh reflects the regional average for the western states and also approximates an emission factor for marginal electricity generation available in the market. To establish a completely transparent, reasonably simple, and sufficiently rigorous method to determine this emission factor to support the cap-and-trade program, CPUC staff developed a prototype default emission calculator which was vetted through stakeholder discussions held by the WCI Electricity Team as well as the Interagency Electricity Working Group comprised of ARB, CPUC, and CEC staff. ARB staff conducted a reporting workshop in March of 2010 at which the calculator was presented to stakeholders and feedback requested.

The default emission factor is calculated as the total emissions divided by the total net generation of all marginal sources and approximates a load duration curve model. Scenario analyses are facilitated by allowing the user to set linked jurisdictions, marginal facility capacity factor, and transmission losses. The calculator was developed using data from the Energy Information Administration reported by the electricity industry including generator types and capacities, quantities of fuel consumed, net generation, and whether the facility is a combined heat and power (CHP) unit. Using this EIA information, the calculator provides default emission factors by assigning facilities to either a marginal or non-marginal category. In cases where staff identified that a facility did not operate the entire year, the nameplate capacity was multiplied by the fraction of the year the facility operated. For facilities comprised of multiple units combusting different fuels and operating under different conditions, the units are separated to allow calculation of a representative capacity factor.

Staff used a capacity factor of 60 percent, consistent with Senate Bill 1368 (SB 1368 2006), which prohibits any load-serving entity from entering into long-term contracts for baseload generation that exceeds a GHG emission performance standard established by the CPUC. SB 1368 defines a baseload facility as a facility with a capacity factor of "at least 60 percent." Therefore, staff established a "marginal" facility as a facility with a capacity factor less than 60 percent. In addition, facilities that are not dispatchable are excluded, such as facilities with must-take contracts such as CHP or facilities that provide energy as-available such as wind and solar. Hydroelectric power was also excluded since it can be claimed as a specified source of electricity under staff's proposal.

During the *2009 Integrated Energy Policy Report* (CEC IEPR 2009) preparation, CEC staff analyzed data and determined the 2006, 2007, and 2008 data years are representative for high, medium and low hydroelectricity generation years. ARB staff based the default emission factor for reporting imported unspecified electricity on the average for these three years, consistent with the methodology for setting the cap under the cap-and-trade program.

Summary of Section 95111(b)(2), Calculating GHG Emissions from Specified Facilities or Units.
Required methods for calculation of GHG emissions associated with sources of imported electricity from specified facilities or units are provided in section 95111(b)(2). Electric power entities must use the equation provided, which includes ARB emission factors. ARB will calculate and publish on its Mandatory Reporting Program website the needed emission factors for each specified facility or unit that is registered by electric power entities with ARB *a priori*. ARB will calculate the emission factors for each registered facility or unit based on a preferred ranking of data sources described in section 95111(b)(2). Given the expected timing of available data, staff anticipate that the facility or unit-specific emission factors will be based on data from the year immediately prior to the data year. ARB will publish and update these emission factors with sufficient time for reporting entities to incorporate into their calculations before the reporting deadline.

Rationale for Section 95111(b)(2).
This provision is necessary to allow electric power entities to calculate and report GHG emissions (MT of CO_2e) for imported electricity (MWh) associated with facilities or units that are identified by ownership share or in written contracts as electricity designated to serve California load. It is also necessary to demonstrate how ARB will calculate and publish the needed emission factors, and to assure rigorous and consistent accounting.

Summary of Section 95111(b)(3), Calculating GHG Emissions for Imported Electricity from Specified Asset-Controlling Suppliers.
This provision establishes the required methods for calculating GHG emissions associated with sources of imported electricity from specified asset-controlling suppliers. BPA, reporting to ARB as a marketer, and other electricity importers who procure BPA system power, must use the BPA system power emission factor calculated and published by ARB. BPA has the option of accepting the ARB calculated emission factor based on the method specified in this section or voluntarily providing additional specified data to support a more refined calculation.

Rationale for Section 95111(b)(3).
This provision is necessary to allow electric power entities to calculate and report GHG emissions (MT of CO_2e) associated with imported electricity (MWh), primarily hydroelectricity, from the BPA system power pool. The BPA system power emission factor will be less than the unspecified source default emission factor; and therefore, must be reported as a specified source to accurately account for GHG emissions. The reasoning for allowing a less precise calculation for a BPA system power emission

factor is that ARB staff anticipates the more precise data will not make a significant change to the emission factor since BPA only purchases unspecified power, some of which is fossil-based power, to balance its hydroelectric system. Unspecified power purchases have been reported as approximately 10 percent of total system sales (MWh) in 2008 and 2009. The default emission factor for BPA system power may need to be adjusted upward, depending on the extent to which BPA sells hydroelectric power only in the Pacific Northwest and the power sold into California carries a greater percentage of the unspecified balancing power.

Summary of Section 95111(b)(4), Calculating GHG Emissions for Imported Electricity from Specified Multi-jurisdictional Retail Providers.
This provision sets forth the required methods for calculating GHG emissions associated with sources of imported electricity from specified multi-jurisdictional retail providers. The two multi-jurisdictional utilities that serve California, PacifiCorp and Sierra Pacific Power Company, will use their respective system power pool emission factors calculated and published by ARB to report GHG emissions associated with their imported electricity. ARB will calculate their respective emission factors based on additional data required in section 95111(d) as well as GHG data they report to U.S. EPA and data they report to the EIA. The emission factors will be posted on the ARB Mandatory Reporting website.

Rationale for Section 95111(b)(4).
This provision is necessary to allow reporting entities to calculate and report GHG emissions (MT of CO_2e) associated with imported electricity (MWh) from the system power pools of PacifiCorp and Sierra Pacific Power Company, which are integrated utilities and are recognized by the ARB as asset-controlling suppliers. ARB staff anticipate that the system power emission factors are significantly higher than the default emission factor provided for unspecified sources of electricity; and therefore, they must be reported as specified sources to accurately account for GHG emissions.

Summary of Section 95111(c), Greenhouse Gas Emissions Data Report: Additional Requirements for Retail Providers, excluding Multi-jurisdictional Retail Providers.
Retail providers will continue to report retail sales to the ARB. Retail sales will be published on ARB's website and subject to ARB audit and enforcement, but will not require independent verification. Retail providers who are also importers of electricity must identify and claim specified imported electricity from those facilities in which they have an ownership share or contract. This provision clarifies that imported electricity from these sources cannot be claimed as unspecified power. In addition, California's share of electricity from high-emitting facilities that is sold outside of California, is reported. Retail providers who are also importers of electricity must report electricity imported on their behalf to serve their load.

Rationale for Section 95111(c).
Retail sales are needed to support the cap-and-trade program in calculating free allocations of allowances. It is not necessary to require verification of retail sales, since it will be the only information required for the many retail providers who are neither

importers nor exporters of electricity. Since information on electricity transactions between sources and sinks inside California is no longer needed to support the cap-and-trade program, many retail providers will only report retail sales. Accuracy of reported retail sales continues to be important, as free allocations will be calculated according to a method that will transition to a retail sales basis. Data quality will be protected by making the data public on ARB's mandatory reporting program website and subject to ARB audit and enforcement.

In addition, California's share of electricity from high-emitting facilities that is sold outside of California is reported for two reasons. First, this is needed as a data quality check on reported imported electricity. Second, it is critical to support ARB analysis of emissions reductions attributable to electricity consumed in California that do not also reduce net emissions in the total western region bulk system power pool.

Continuing from the current ARB requirement (ARB MRR 2007), retail providers who are also importers of electricity, report electricity imported on their behalf to serve their load as a data quality check to assure all imported electricity is reported to ARB. This requirement has been discontinued for retail providers who are not electricity importers, to keep their reporting obligation limited to retail sales only.

Summary of Section 95111(d), Greenhouse Gas Emissions Data Report: Additional Requirements for Multi-Jurisdictional Retail Providers.
Under staff's proposal, the two multi-jurisdictional retail providers in California, PacifiCorp and Sierra Pacific Power Company, continue to report the same information as required under the current ARB mandatory reporting program (ARB MRR 2007) with two exceptions. First, they must now report associated GHG emissions with their electricity transactions, consistent with the proposed requirement for other retail providers. Second, multi-jurisdictional retail providers are no longer required to submit and verify facility-specific GHG reports to ARB for out-of-state facilities under their operational control. Instead, ARB will accept U.S. EPA GHG reports (USEPA MRR 2009-2010) for these facilities. In cases where their facilities may not be required to report to U.S. EPA, ARB will accept Energy Information Administration data from form EIA-860, "Annual Electric Generator Report," and form EIA-923, "Power Plant Operations Report."

Multi-jurisdictional retail providers must continue to report wholesale purchases, sales, and facility information to support ARB calculation of a supplier-specific emission factor. They must use this factor when calculating and reporting GHG emissions associated with their imported electricity.

Rationale for Section 95111(d).
This provision is necessary to support the determination of compliance obligations under the ARB cap-and-trade program for multi-jurisdictional retail providers and for other electricity importers that procure system power from either PacifiCorp or Sierra Pacific Power Company and import it into California.

Summary of Section 95111(e), Greenhouse Gas Emissions Data Report: Additional Requirements for WAPA and DWR.
This provision requires DWR and WAPA to report:

- Individual and total pump loads from WAPA Central Valley Project, MWh.
- Individual and total pump loads from DWR State Water Project, MWh.
- Imported electricity, MWh and MT of CO_2e.
- Exported electricity, MWh and MT of CO_2e.
- Retail sales of electricity to end-users, MWh.

Rationale for Section 95111(e).
The purpose of collecting the data is provided as the rationale in the table below.

Required Data	**Purpose**	**New or Continuing Requirement**
Individual and total pump loads from WAPA Central Valley Project, MWh	ARB analysis of water conservation and efficiency measures in Scoping Plan	New
Individual and total pump loads from DWR State Water Project, MWh	ARB analysis of water conservation and efficiency measures in Scoping Plan	Continuing
Imported electricity, MWh and MT CO_2e	Calculate Cap-and-Trade compliance obligation and support ARB GHG Inventory	MWh—Continuing MT of CO_2e —New
Exported electricity, MWh and MT CO_2e	Support ARB GHG Inventory	MWh—Continuing MT of CO_2e —New
Retail sales of electricity to end-users, MWh	Calculate possible Cap-and-Trade free allocation to retail providers and inform analyses for Renewable Electricity Standard Program	Continuing

Summary of Section 95111(f), Greenhouse Gas Emissions Data Report: Additional Requirements for Asset-Controlling Suppliers.
ARB will assign a system emission factor for Bonneville Power Administration (BPA) system power, for multi-jurisdictional retail providers, and for asset-controlling suppliers with a system emission factor greater than 1100 lbs CO_2e/MWh.

Bonneville Power Administration supplies primarily hydroelectric power from their system to California, supplemented by wholesale purchases of unspecified electricity to operate their system. BPA and other electric power entities that import BPA system power into California must use BPA's system emission factor calculated by ARB and published on the ARB Mandatory Reporting website. As specified in section 95111(b), ARB will set this emission factor equal to 20 percent of the default emission factor for electricity from unspecified sources, or base the factor on a more refined calculation from a previously verified GHG emissions data report submitted on a voluntary basis to ARB that meets the additional requirements for asset-controlling suppliers required

under the current ARB MRR (ARB MRR 2007) or under this proposal pursuant to section 95111(f).

Other asset controlling suppliers import electricity into California and sell their system power to other electric power entities that import electricity into California. When the estimated emission factor for these suppliers is greater than 1100 lbs CO_2e/MWh, approximately the equivalent of the emission performance standard established by the CPUC and CEC for long term power contracts, the associated emission factor published by ARB must be used to calculate GHG emissions. This includes multi-jurisdictional retail providers.

Rationale for Section 95111(f).
This provision is necessary to support the determination of compliance obligations for the ARB cap-and-trade program for (1) BPA, who imports electricity into California, and for (2) other electricity importers that procure system power from BPA and import it into California. The additional reporting requirements to support calculation of a system emission factor for multi-jurisdictional retail providers are provided in section 95111(d) for clarity.

Staff is proposing that asset-controlling suppliers—other than BPA, PacifiCorp, and Sierra Pacific Power Company—that may import electricity directly into California or supply it to other electric power entities that then import it into California report the additional information under this section so that GHG emissions are accurately reported. Without this information, the imported electricity may be incorrectly reported from unspecified sources and associated with the lower emission factor intended for cleaner, dispatchable, marginal resources which are typically fueled by natural gas.

No electric power entities have requested a system power emission factor from ARB and met the voluntary reporting requirements in the current version of the ARB Mandatory Reporting regulation, which was designed for suppliers with primarily renewable energy facilities in their fleets or suppliers with a limited quantity of unspecified wholesale purchases used to supplement their fleet generation (ARB MRR 2007). Due to lack of interest from electric power entities and staff concern about the potential for resource shuffling to undermine the environmental integrity of the cap-and-trade program, this previous reporting provision is not included in staff's proposal. Resource shuffling is discussed in more detail in the rationale for section 95111(g).

Summary of Section 95111(g), Requirements for Claims of Specified Sources of Imported Electricity and Associated Emissions.
This section sets forth specific reporting requirements to adequately track the validity of claims for lower GHG emission resources. In addition, reporting requirements are included to track expected resource shuffling and shifting resource investment that will occur outside the regulatory authority of the ARB and result in no net emission reductions in the western region. This provision also establishes a process for electricity importers to register their specified sources and suppliers with ARB and receive specified emission factors for different types of electricity generating resources.

Rationale for Section 95111(g).
This section is necessary for ARB to support the environmental integrity of the California cap-and-trade program through accurate and complete GHG emissions reporting associated with imported electricity, within ARB's regulatory authority. In addition, ARB needs information to determine the extent to which resource shuffling and shifting resource investment in the western region bulk system power pool results in increased, decreased, or no net change in GHG emissions in the western region.

ARB is considering additional provisions that would clarify how GHG emissions from specified sources will be reported. In this proposal, accounting conventions are specified to limit financial incentives to change the resource mix for imported electricity in ways that merely shift GHG emissions from California to other jurisdictions, consistent with the intent of the current ARB regulation (ARB MRR 2007) and the *WCI Final Essential Requirements of Mandatory Reporting* (WCI ERMR 2009).

Renewable energy credits (RECs) cannot be used in GHG reporting. This is consistent with the intent of the California cap-and-trade program and the WCI cap-and-trade program (WCI RECs Accounting 2008, WCI RECs Announcement 2010) to provide a smooth transition to a future federal source-based program. A smooth transition requires that RECs from California renewable energy facilities do not have lesser value than RECs from out-of-state facilities, simply due to GHG attribution from the California cap-and-trade program.

Summary of Section 95111(g)(1), Registration of Specified Sources and Suppliers.
This provision requires electricity importers to register specified sources and suppliers and report associated GHG emissions with ARB.

Rationale for Section 95111(g)(1).
This provision is necessary to assure accurate tracking of imported electricity and associated emissions from specified sources and suppliers.

Summary of Section 95111(g)(2), Emission Factors.
The provision sets forth the requirement to use source-specific emission factors calculated by ARB and posted to the ARB Mandatory Reporting website.

Rationale for Section 95111(g)(2).
This provision is necessary to assure accurate tracking of imported electricity and associated emissions from specified sources and suppliers.

Summary of Section 95111(g)(3), Owned Sources.
This provision requires electricity importers to report imported electricity as specified imports when they have ownership in the facility or unit.

Rationale for Section 95111(g)(3).
This provision is necessary to clarify that electricity imported from these sources cannot be reported as unspecified and receive the default emission factor.

Summary of Section 95111(g)(4), Delivery Tracking Conditions Required for Specified Electricity Imports.
This provision sets forth the required conditions for tracking deliveries of specified imported electricity.

Rationale for Section 95111(g)(4).
This provision is necessary to assure accurate tracking of imported electricity and associated emissions from specified sources and suppliers.

Summary of Section 95111(g)(5), High GHG-Emitting Facilities or Units.
This provision contains the requirements for reporting California's share of out-of-state electricity generation that is sold outside California and not imported.

Rationale for Section 95111(g)(5).
This provision is necessary to provide information for ARB to determine the extent to which resource shuffling and shifting resource investment in the western region bulk system power pool results in increased, decreased, or no net change in GHG emissions in the western region.

Summary of Section 95111(g)(6), Low GHG-Emitting, Existing, Fully Committed Resources: Nuclear and Large Hydroelectric Resources.
This provision establishes the accounting conventions for reporting imported electricity from nuclear and large hydroelectric facilities.

Rationale for Section 95111(g)(6).
This provision is necessary to provide reasonable limitations on resource shuffling and to provide information for ARB to determine the extent to which resource shuffling and shifting resource investment in the western region bulk system power pool results in increased, decreased, or no net change in GHG emissions in the western region. This provision is consistent with the intent of the current ARB reporting requirements (ARB MRR 2007) and the WCI reporting requirements (WCI ERMR 2009).

Summary of Section 95111(g)(7), Substitute Electricity.
This provision sets forth the methods for reporting substitute electricity.

Rationale for Section 95111(g)(7).
This provision is necessary to assure accurate tracking of imported electricity and associated emissions from specified sources and suppliers.

Summary of Section 95112, Electricity Generation and Cogeneration.

This section specifies the overall greenhouse gas emissions reporting requirements and methods for electricity generation facilities and cogeneration facilities.

Rationale for Section 95112.
This section is necessary to complete the California energy generation inventory, to provide consistent and equitable reporting requirements, to support greenhouse gas cap-and-trade programs, and to harmonize with U.S. EPA reporting requirements. The introductory paragraph of section 95112 unifies the two different sections in the U.S. EPA rule (Subparts C & D of 40 CFR 98) that cover electricity generating units (EGU). The additional California-specific reporting requirements apply to all units that generate electricity, notwithstanding which U.S. EPA rule section is applicable.

Summary of Section 95112(a), Basic Information for EGUs.
This provision requires the reporting of basic information about EGUs that is essential for California's energy generation inventory and verification of emissions report. The information includes generation capacity, power generation, fuel consumption, emissions of individual greenhouse gases in metric tons, fuel characteristic data, electricity consumed on-site, and electricity sales.

Rationale for Section 95112(a).
This provision is necessary to meet AB 32 requirements for complete reporting of this sector, as well as to monitor these units for cap-and-trade. U.S. EPA's bifurcation of this sector into Part 75 and non-Part 75 creates anomalies because Part 75 units are not required to report some information important to our knowledge of electricity generation in California. To ensure complete, accurate, and credible GHG emissions data, it is required to include comprehensive data collection and reporting. This requirement for data collection and reporting helps to identify any data errors and greatly assists with the verification of GHG data reports for accuracy and completeness.

Summary of Section 95112(b), Basic Information for Cogeneration Units.
This provision requires the operators of electricity generation and cogeneration units to report basic information about cogeneration unit that is essential for California's energy generation inventory and verification of emissions report. In addition to reporting the basic information required by section 95112(a), operators must also report information on cogeneration technology, useful thermal output, thermal energy purchases, and supplemental firing.

Rationale for Section 95112(b).
This provision is necessary to meet AB 32 requirements for complete reporting of this sector, as well as to monitor these units for cap-and-trade. This information will also support cap-and-trade benchmarking and the energy efficiency and co-benefits regulation. To ensure complete, accurate, and credible GHG emissions data, it is required to include comprehensive data collection and reporting. This requirement for

data collection and reporting helps to identify any data errors and greatly assists with the verification of GHG data reports for accuracy and completeness.

Summary of Section 95112(c), CO_2 from Fossil Fuel Combustion.
This provision establishes the method operators must use for estimating CO_2 emissions for combustion emissions from this industrial sector. The provision refers to section 95115 of the regulation, which specifies on the basis of fuel type and unit size which U.S. EPA methods may be selected for calculating emissions of CO_2 from combustion.

Rationale for Section 95112(c).
This provision is needed to provide data of sufficient quality for the cap-and-trade program and consistent with combustion emissions methods required in other industrial sectors. The limitations in section 95115 on selection of an appropriate calculation method are designed to account for fuel carbon variability, which will ensure accurate emissions estimation for combustion, the largest and most important source of overall emissions.

Summary of Section 95112(d), Monitoring, Data, and Records.
This provision requires that monitoring, data, records, and the other information collected or reported are consistent with the provisions of the CO_2 combustion method(s) used by the reporting entity in the previous section.

Rationale for Section 95112(d).
This provision is needed to ensure complete and accurate GHG combustion emissions data are collected by the reporting entity and retained for verification purposes. Because it will help ensure that data are properly collected and that errors can be corrected, the provision is critical for the credibility of the information that becomes the basis of emissions trading.

Summary of Section 95112(e), Biomass Emissions for Units Reporting Under 40 CFR Part 75.
This provision requires operators of 40 CFR Part 75 EGUs to report consumption of biomass-derived fuels and the biogenic portion of their CO_2 emissions.

Rationale for Section 95112(e).
This provision is necessary for determining the compliance obligation of 40 CFR Part 75 units under the cap-and-trade regulation. The U.S. EPA rule does not require operators of Part 75 units to report biogenic portion of CO_2 emissions, which does not have a compliance obligation in cap-and-trade, separately from fossil-based emissions. Reporting of biomass-derived fuel consumption and biogenic CO_2 emissions is essential for cap-and-trade and is needed to ensure consistency with WCI design recommendations.

Summary of Section 95112(f), CO_2 and CH_4 Emissions from Geothermal Facilities.
This provision retains reporting requirements for geothermal facilities from the current California GHG reporting regulation. It requires reporting of CO_2 and CH_4 emissions

using source-specific emission factors derived from an ARB approved measurement plan.

Rationale for Section 95112(f).
This provision is necessary to meet AB 32 requirements for complete reporting of emissions for the electricity sector. Geothermal processes release a substantial amount of CO_2 and CH_4. 40% of the geothermal facilities that reported CO_2 emissions to ARB in 2009 and 2010 indicated that their annual facility emissions are greater than 100,000 metric tons of CO_2.

Although CH_4 emissions reporting is not required by the current California regulation, information provided by geothermal facilities staff and published literature indicate that CH_4 emissions from geothermal sources can also be significant. Many geothermal facilities are already measuring CH_4 emissions as a part of their periodic emission monitoring plan. The additional reporting of CH_4 emissions is consistent with the AB 32 mandate.

This provision requires operators to calculate emissions using source specific emission factors derived from an ARB-approved measurement plan. In the proposed rule, the operator no longer has the option of using default emission factor for GHG reporting. Analysis conducted by ARB staff showed that the current default emission factor is neither conservative nor representative of the measured emissions from the various geothermal reservoirs in California. Because all geothermal operators are either already reporting using source specific emission factors, or making plans for obtaining source specific emission factors in 2010 and beyond, this change in requirement is expected to have little impacts on geothermal facilities' reporting efforts.

Summary of Section 95112(g), Hydrogen Fuel Cells.
This provision requires the reporting of basic information about stationary hydrogen fuel cell EGUs. Operators must report their generation capacity, power generation, fuel/feedstock consumption, provider of fuel/feedstock, and basic cogeneration information if applicable.

Rationale for Section 95112(g).
This provision is necessary to meet AB 32 requirements for complete reporting of this sector. Stationary hydrogen fuel cells emit CO_2 emissions from the hydrogen production process, and depending on the source of the fuel/feedstock, the CO_2 emissions can either be fossil-based or biomass-based. Most existing fuel cells in California are experimental and too small to report on their own (except as part of a facility with larger stationary combustion units), but larger fuel cell units likely to exceed reporting thresholds are in the planning stages.

Summary of Section 95112(h), Missing Data Substitution Procedures.
This provision specifies the procedures for the substitution of missing data for this industrial sector.

Rationale for Section 95112(h).
This provision is necessary because a primary goal of the reporting program is to collect accurate GHG emissions data in support of cap-and-trade. This helps to ensure that the emissions are not underestimated for the facility, and also makes it unfavorable for reporters to attempt to report using incomplete or false data.

Summary of Section 95113, Petroleum Refineries.

This section specifies GHG reporting requirements for petroleum refining facilities.

Rationale for Section 95113.
This section is necessary because petroleum refineries represent a significant source of GHG emissions in California. California refineries have been reporting their GHG emissions to ARB for the past two years. Section 95113 harmonizes with GHG reporting requirements found in the U.S. EPA Mandatory Reporting Rule and provides cap-and-trade quality data for GHG emissions associated with this important source.

Summary of Section 95113(a), CO_2 from Fossil Fuel Combustion.
This provision sets forth the reporting requirements for combustion emissions.

Rationale for Section 95113(a).
This provision is necessary to ensure that operators report CO_2 combustion emissions using methods designed to produce cap-and-trade quality data while allowing the use of a Tier 1 methodology for de minimis sources and certain standardized fuels. This provision also is needed to simplify reporting requirements.

Summary of Section 95113(b), Monitoring, Data and Records.
This provision harmonizes monitoring, data and records requirements with the provisions for reporting of GHG emissions from this sector. This section requires that operators meet applicable requirements for monitoring, missing data procedures, data reporting and records retention.

Rationale for Section 95113(b).
This provision is necessary to detail the requirements for monitoring GHG emissions, the data that reporters are required to retain, and methods for replacing missing data. It also ensures an accurate verification, which is one of the cornerstones of an effective GHG reporting program.

Summary of Section 95113(c), Refinery Fuel Gas Sampling.
This provision establishes a date (January 1, 2013) by which the necessary monitoring equipment and procedures must be in-place to measure daily carbon content of refinery fuel gas.

Rationale for Section 95113(c).
This provision is necessary because refinery fuel gas is a very important fuel used extensively in California refineries. The composition of refinery fuel gas can also be

highly variable. U.S. EPA requires daily sampling for this fuel but allows weekly sampling in situation where the required equipment is not in place. With the exception of two "small" refineries, required equipment and procedures should be in-place at California refineries. This provision is consistent with the WCI Harmonization draft, but an additional year is provided in this provision to allow such equipment to be installed.

Summary of Section 95113(d), Calculating CO_2 from Flares.
This provision establishes reporting requirements and calculation methods for refinery flares. This provision requires that operators use the more stringent of two EPA methods for normal flare operations, while allowing the use of the alternative method for periods of start-up, shut-down and malfunction.

Rationale for Section 95113(d).
This provision is necessary to ensure that emissions from flares are calculated consistently and included in the reporting entities' emissions data reports.

Summary of Section 95113(e), Calculating CO_2 from FCCUs and Fluid Coking.
This provision establishes reporting requirements for FCCU units and Fluid Cokers. The provision removes the U.S. EPA 10,000 barrels/day threshold.

Rationale for Section 95113(e).
This provision is necessary because all refinery based FCCU units and fluid cokers in California are currently required to report combustion and process emissions regardless of rated capacity. Thus, consistent with the WCI Harmonization draft, it was not deemed necessary to provide alternative, less stringent methods for some smaller units.

Summary of Section 95113(f), Calculating CH_4 from Delayed Coking Units.
This provision defines reporting requirements for methane emissions which result when a delayed coker vessel is depressurized prior to coke un-loading. Operators are required to calculate vessel void fraction rather than use a default factor and measure the methane content of coke cutting gases semi-annually rather than use a default value.

Rationale for Section 95113(f).
This provision is necessary because it will produce more accurate and precise emissions estimates.

Summary of Section 95113(g), Uncontrolled Blowdown Systems.
This provision requires that operators use the more stringent U.S. EPA option process vent methodology to calculate emissions from uncontrolled blowdowns.

Rational for Section 95113(g).
This provision is necessary because alternative methodologies such as using a default emissions factor, were not considered sufficiently rigorous for a cap-and-trade program.

Summary of Section 95113(h), Data Reporting Requirements for Flares.
This provision sets forth reporting requirements for emissions from flares.

Rationale for Section 95113(h).
This provision is necessary to align with the modified reporting methods. This change is consistent with the WCI Harmonization draft and ensures emissions from flares are reported.

Summary of Section 95113(i), Data Reporting Requirements for FCCUs and Coking Units.
This provision clarifies that when an operator calculates CO_2 emissions from fluid catalytic cracking units or fluid coking units consistent with section 95115(f), the operator does not have to report data required by 40 CFR §98.256(f)(9).

Rationale for Section 95113(i).
This provision is necessary to align with the modified reporting methods. This change is consistent with the WCI Harmonization draft.

Summary of Section 95113(j), Data Reporting Requirements for Uncontrolled Blowdown Systems.
This provision clarifies that when operators calculate CH_4 emissions from uncontrolled blowdown systems consistent with section 95113(h), the operator must report information for process vents as required by 40 CFR §98.256(l) in lieu of 40 CFR §98.256(m)(2).

Rationale for Section 95113(j).
The provision is necessary to align with the modified reporting methods. This change is consistent with the WCI Harmonization draft.

Summary of Section 95113(k), Records that must be Retained.
This provision establishes additional data retention requirements for process vent emissions which the operator determines are below the reporting threshold.

Rationale for Section 95113(k).
This provision is necessary because these added record retention requirements are required to demonstrate that process vent emissions did not exceed specified thresholds for methane and carbon dioxide content. This is consistent with the WCI Harmonization draft.

Summary of Section 95113(l) Missing Data Substitution Procedures.
This provision establishes missing data substitution procedures.

Rationale for Section 95113(l).
This provision is necessary to provide a strong incentive for operators to generate as complete a data set as possible, while specifying how to generate substitution data in circumstances where data was unavoidably lost.

Summary of Section 95113(l)(1).
This provision directs operators to use the missing data provision contained in section 95115 of this article.

Rationale for Section 95113(l)(1).
This provision is necessary to establish standardized missing data provisions for all operators who use Section 95115 – Stationary Fuel Combustion Sources. The application of these requirements for all operators ensures data consistency across multiple facility types.

Summary of Section 95113(l)(2).
This provision establishes missing data provisions for petroleum refiners when reporting emissions from other Stationary Fuel Combustion Sources.

Rationale for Section 95113(l)(2).
This provision is required to provide petroleum refiners with a standard method for reporting missing data. This provision is designed to incentivize complete collection of required data while providing reporters with a method for replacing missing data when necessary.

Summary of Section 95113(m), Additional Data to Support Benchmarking.
This provision requires the reporting of additional data parameters to support benchmarking activities.

Rationale for Section 95113(m).
This provision is needed to allow ARB to collect and calculate data that will serve as the foundation for benchmarking activities. Benchmarking, as part of a cap-and-trade system, helps to protect trade-exposed industries from certain competitive disadvantages. Benchmarking also gives greater value to the most efficient entities, and rewards early actions to reduce emissions.

Summary of Section 95114, Hydrogen Production.

This provision specifies GHG reporting requirements for hydrogen production facilities associated with petroleum refineries and merchant (standalone) hydrogen production facilities.

Rationale for Section 95114.
This provision is necessary because hydrogen is essential to the production of clean transportation fuels and thus California petroleum refineries require large amounts of hydrogen to meet California's stringent fuel standards. Significant process and combustion CO_2 emissions occur during the production of hydrogen and thus an accurate quantification of these emissions is essential. Section 95114 harmonizes with GHG reporting requirements found in the U.S. EPA Mandatory Reporting Rule and

provides cap-and-trade quality data for GHG emissions associated with this important source.

Summary of Section 95114(a), Definition of Source.
This provision requires GHG reporting for hydrogen production facilities which are operated by California petroleum refineries and merchant, or standalone, hydrogen production plants.

Rationale for Section 95114(a).
This provision is necessary to require GHG reporting for all hydrogen production facilities in California that exceed the reporting threshold – both hydrogen production at hydrogen facilities associated with a petroleum refinery and merchant hydrogen plants.

Summary of Section 95114(b), CO_2 from fossil fuel combustion.
This provision sets forth the reporting requirements for combustion emissions.

Rationale for Section 95114(b).
This provision is necessary to require operators to report CO_2 combustion emissions using methods that are designed to produce cap-and-trade quality while allowing the use of Tier 1 methodology for de minimis sources and certain standardized fuel, and it also is needed to simplify reporting requirements.

Summary of Section 95114(c), Monitoring, Data and Records.
This provision harmonizes monitoring, data and records requirements with the provisions for reporting GHG emissions from this sector. This section requires that operators meet applicable requirements for monitoring, missing data procedures, data reporting and records retention.

Rationale for Section 95114(c).
This provision is necessary to detail the requirements for monitoring GHG emissions, the data that reporters are required to retain, and methods for replacing missing data. It also ensures an accurate verification, which is a cornerstone of an effective GHG reporting program.

Summary of Section 95114(d), CO_2 Process Emissions.
This provision requires the use of weighted average carbon content values for fuel and feedstock consumed at hydrogen production facilities.

Rationale for Section 95114(d).
This provision is necessary because the use of weighted average carbon content values allows operators to determine feedstock and fuel carbon content from a composite sample rather than requiring analysis on a more frequent basis while still retaining the required data quality. For example, four weekly samples might be composited to generate a monthly sample which is then submitted for carbon content analysis. The resulting data will accurately represent the monthly fuel composition while requiring only one analysis instead of four.

Summary of Section 95114(e), Sampling Frequencies.
This provision establishes sampling frequencies for gaseous, liquid and solid fuel and feedstock. It also allows composite sampling for liquid and solid samples, thus significantly decreasing analysis costs.

Rationale for Section 95114(e).
This provision is necessary to reduce analysis frequency while still maintaining high resolution sampling and data quality.

Summary of Section 95114(e)(1).
This provision establishes sampling requirements for gaseous fuels and feedstocks. Reporters must use a weighted average monthly carbon content value derived from daily analysis for gaseous fuels other than natural gas. A single monthly carbon content analysis is required for natural gas.

Rationale for Section 95114(e)(1).
This provision is necessary because composition of non-standard gaseous fuels such as refinery fuel gas is variable and thus a daily sampling regime is required to accurately account for this emissions source.

Summary of Section 95114(e)(2).
This provision establishes sampling requirements for liquid fuels and feedstocks. Reporters must use a weighted average monthly carbon content value derived from monthly analysis of daily composite samples for each liquid fuel or feedstock.

Rationale for Section 95114(e)(2).
This provision is necessary because daily sampling is designed to capture compositional variations of liquid fuels and feedstocks, while use of a composite sample for analysis significantly reduces analytical measurements and still maintains required data quality.

Summary of Section 95114(e)(3).
This provision establishes sampling requirements for solid fuels and feedstocks. Reporters must use a weighted average monthly carbon content value derived from monthly analysis of daily composite samples for each liquid fuel or feedstock.

Rationale for Section 95114(e)(3).
This provision is necessary because daily sampling is designed to capture compositional variations of solid fuels and feedstocks, while use of a composite sample for analysis significantly reduces analytical measurements and still maintains required data quality.

Summary of Section 95114(f), Weighted Average Sampling.
This provision details the arithmetic methodology for calculating weighted averages and details the records which reporting entities must retain.

Rationale for Section 95114(f).
This provision is necessary because the use of high frequency sampling to generate a weighted average fuel or feedstock carbon content value significantly reduces the analytical burden on reporters while still maintaining data quality.

Summary of Section 95114(f)(1).
This provision establishes sampling guidelines for collecting weighted average samples.

Rationale for Section 95114(f)(1).
This provision is necessary to provide data consistency and maintain data quality.

Summary of Section 95114(f)(2).
This provision establishes the mathematical methodology for calculating weighted average values.

Rationale for Section 95114(f)(2).
This provision is necessary to ensure data consistency and reduce reporting errors.

Summary of Section 95114(f)(3).
This provision establishes data retention requirements in cases where composite samples are collected.

Rationale for Section 95114(f)(3).
Data retention requirements are necessary to provide verification of reported emissions.

Summary of Section 95114(g). Data Reporting Requirements.
This provision modifies data reporting requirements to match the modified sampling and reporting frequencies. It also provides operators with a reporting method that avoids double-counting emissions that have been included elsewhere in the facility report.

Rationale for Section 95114(g).
This provision is necessary because an accurate GHG accounting procedure must avoid double-counting of emissions.

Summary of Section 95114(h), Missing Data Substitution Procedures.
This provision establishes missing data substitution procedures.

Rationale for Section 95114(h).
This provision is necessary because these missing data substitution procedures are designed to provide a strong incentive for reporting entities to generate as complete a data set as possible, while specifying how to generate substitution data in circumstances where data was unavoidably lost.

Summary of Section 95114(h)(1).
This provision establishes missing data requirements for refinery related stationary combustion emissions.

Rationale for Section 95114(h)(1).
This provision is necessary because missing data requirements are required to ensure that all reporting entities use the same methodology to report missing data. Consistent missing data requirements for all stationary combustion are necessary to ensure industry wide data consistency.

Summary of Section 95114(h)(2).
This provision establishes missing data requirements for all other GHG data which refinery operators are required to report.

Rationale for Section 95114(h)(2).
This provision is necessary because missing data requirements are necessary to ensure data consistency across all California refineries.

Summary of Section 95115, Stationary Fuel Combustion Sources.

Summary of Section 95115.
This provision specifies greenhouse gas emissions reporting requirements and methods for general stationary fuel combustion sources. This component of the regulation applies to multiple industrial sectors, and includes devices that combust solid, liquid, or gaseous fuels, generally for the purposes of generating steam, producing electricity, providing useful heat or energy for industrial, commercial, or institutional use, or reducing the volume of waste by removing combustible matter. Stationary sources include, but are not limited to, boilers, simple and combined-cycle combustion turbines, engines, incinerators, and process heaters. This provision provides common methods for estimating CO_2, CH_4, and N_2O emissions from general stationary fuel combustion sources.

Overall, section 95115 uses the U.S. EPA stationary source combustion methods for GHG emissions as its basis. This approach substantially harmonizes the proposed ARB reporting requirements with U.S. EPA greenhouse gas reporting requirements for stationary combustion, which helps to simplify reporting and reduce costs for those subject to the rule. However, in certain cased, modifications to the U.S. EPA baseline requirements are needed to support ARB program needs. The remaining provisions of section 95115 describe these modifications.

Rationale for Section 95115.
This section helps to ensure consistent and accurate reporting across all industry sectors. The section provides consistent calculation methods and equitable reporting requirements, which are needed to support greenhouse gas emission inventory and cap-and-trade programs.

Summary of Section 95115(a), CO_2 from Steam Producing Units.
This provision provides the requirements from estimating CO_2 emissions from combustion units at facilities that produce steam. It provides specific emission estimation requirements based on the fuel burned. Within the U.S. EPA reporting regulation, units that produce steam may use Tier 2 calculation methods for any fuel. This provision allows use of the Tier 2 steam method for municipal solid waste and solid biomass fuels. However, the method may not be used for estimating combustion from high-emitting and variable fossil fuels, such as coal.

Rationale for Section 95115(a).
This provision limits the use of the less accurate Tier 2 steam-based method for certain fossil fuels because the method provided in the U.S. EPA MRR does not provide sufficient accuracy for estimating fossil fuel emissions for sources in a cap-and-trade program. This approach is consistent with the Western Climate Initiative reporting approach for steam generating units. The steam method is acceptable for biomass fuels because they are not included in the cap and trade system. For municipal solid waste (MSW), the method is allowed because MSW is typically a highly variable fuel, so generally there is not a more accurate and reasonable alternative for estimating GHG emissions for MSW combustion.

Summary of Section 95115(b), CEMS CO_2 Monitor.
This provision requires that if a new continuous emissions monitoring system (CEMS) is installed for the purpose quantifying CO_2 emissions, the operator must install a CO_2 monitor for direct CO_2 monitoring. Operators who use O_2 monitors to report CO_2 emissions, and conduct Relative Accuracy Test Audits for the unit, must use the RATA data for CO_2 estimates.

Using CEMS, emissions of CO_2 may be estimated either using instrumentation that directly measures CO_2 concentrations, or using instrumentation that measures oxygen (O_2) concentrations. For fuels with variable carbon content, the CEMS that directly measure CO_2 provide substantially more accurate emission estimates than systems that use oxygen measurements. This is because the use of oxygen-based CEMS requires the use of conversion factors to approximate CO_2 concentrations, rather than providing a direct measurement of the concentrations. Also, the O_2 to CO_2 conversion factors are very generalized by fuel type. The variations of carbon content of solid fuels, in particular, would not be reflected when O_2 monitoring is used. The proposed language does not require retrofitting of existing CEMS systems, but would require new CEMS to include a CO_2 monitor when a flow monitor (required for CO_2 monitoring) is included in the CEMS system.

Rationale for Section 95115(b).
This provision provides improved accuracy and reliability of CO_2 emissions estimates which are needed to support cap-and-trade and other GHG programs. The increased cost to install a CO_2 monitor in comparison to the cost of an O_2 monitor is minor, and the CO_2-based monitor provides significantly improved and reliable emissions data. To reduce potential costs, this provision does not require installation of the new monitor

unless new instrumentation is being installed for other reasons, and it also includes an exclusion for facilities which only consume natural pipeline gas, which can be reasonably estimated using O_2 monitors.

Summary of Section 95115(c), Choice of Tier for Calculating CO_2 Emissions.
This provision provides multiple methods, or Tiers, for estimating GHG emissions for general combustion sources. The application of the Tiers for estimating emissions varies based on the type of fuel used and other factors. Tier 1 allows use of default emission factor and fuels data. Tiers 2 and 3 require sampling and analysis to characterize the fuels burned. Tier 4 requires the use of CEMS. The subsections of this provision, described below, specify which tiers must be used for estimating CO_2 emissions..

Rationale for Section 95115(c).
This provision is included to ensure the highest feasible accuracy for the largest and most important emissions sources, while providing simplified methods where possible, to reduce the costs and complexity of reporting. Where fuels are standardized and have known carbon content, or for *de minimis* emissions, the provision allows use of default emission factors (Tier 1). Heating value analysis (Tier 2) provides accurate emissions estimates for natural gas of pipeline quality, as defined in section 95102. Natural gas is the most common fuel in California, and heating value is usually available from the fuel supplier. Another Tier 2 method is specified for certain solid fuels in steam-producing units. Carbon content analysis (Tier 3) or use of continuous emissions monitoring systems (Tier 4) would be required for fuels that often have variable carbon content, subject to additional limitations in the U.S. EPA rule. This is to ensure the emissions from these fuels are accurately calculated, a necessity especially in a market program.

Summary of Section 95115(c)(1), Selection of Tier 1 or Tier 2 for Specified Fuels.
This provision allows for simplified CO_2 calculation methods for certain common fuels (specified in the regulation), with known and consistent characteristics, and for biomass-derived fuels not subject to a compliance obligation under the cap-and-trade regulation. Tier 1 allows use of default emission factors. Tier 2 requires measured fuel high heat value data for computing CO_2 emissions. This provision also limits the use of these methods to units that do not exceed a rated heat input capacity of 250 mmBtu/hr or less, which depending on the fuel, equates to approximately 125,000 to 200,000 metric tons of CO_2 emissions per year, assuming full annual utilization of 8,760 hours/year.

Rationale for Section 95115(c)(1).
This provision is provided for estimating CO_2 emissions for the fuels specified in Table ES-1 of the regulation. For these fuels, CO_2 emissions can be accurately estimated using default emission factors or default high heat values because the high heat value and carbon content of these standardized fuels has little variation. Therefore, the additional expense and complexity of measuring these parameters is not warranted. For combustion of biomass-derived fuels, not included in the cap-and-trade regulation, the use of Tier 1 or Tier 2 methods is sufficient to adequately characterize facility CO_2

emissions, so the use of higher level tiers is not warranted. Finally, this provision can only be applied to units below the specified size threshold. For very large units, with potentially very large emissions levels, higher accuracy, higher Tier methods are needed to effectively support inventory and cap-and-trade programs.

Summary of Section 95115(c)(2), Selection of Tier 2 for Pipeline Natural Gas and Distillate Fuels.
This provision allows the use of Tier 2 methods for pipeline quality natural gas and distillate fuels (i.e., diesel fuel). The method requires quantification of the high heat value (HHV) of the fuel by either the fuel supplier or the user of the fuel.

Rationale for Section 95115(c)(2).
This provision is included because the use of measured high heat (HHV) data can be used to compute accurate CO_2 emissions estimates for these standardized fuels. However, because of the limited variability which can occur with pipeline natural gas and distillate fuels, the use of Tier 1 methods is not allowed, because it does not require measurement of the fuel characteristics, as Tier 2 does.

Summary of Section 95115(c)(3), Tier Selection for *De Minimis* Emissions.
This provision allows the use of any emission estimation Tier if the reported emissions for the source meet the requirements necessary to be defined as de minimis for the GHG report. Therefore, default emissions factors, HHV data, carbon content data, or CEMS may be used to estimate *de minimis* emissions, unless specifically prohibited by 40 CFR §98.33(b).

Rationale for Section 95115(c)(3).
This provision provides operators flexibility in reporting their *de minims* emissions so they do not have to expend unnecessary resources in order to compute emissions for small, potentially difficulty to quantify, emission sources. Because these sources are, by definition, small relative to the full facility emissions, the necessity for higher quality data is reduced.

Summary of Section 95115(c)(4), Use of Tier 3 and Tier 4 Methods.
This provision specifies that for all other sources subject to section 95115(c) of the regulation, and not specifically excluded in 95115(c)(1)-(3), operators must use either the Tier 3 method or Tier 4 methods. Tier 3 requires measurement of carbon content and Tier 4 requires use of CEMS.

Rationale for Section 95115(c)(4).
This provision is provided to accurately quantify CO_2 emissions from the combustion of variable fuels, or for those operators who already have installed CEMS. For variable fuels such as coal, the use of HHV data does not provide accurate emission estimates. And, if a source already has a properly installed and operating CEMS system, this system provides high quality CO_2 emissions data, so therefore it must be used for emissions estimates.

Summary of Section 95115(d), Source Test Option for N_2O and CH_4.
This provision allows reporters to measure site-specific facility emissions data for nitrous oxide (N_2O) and methane (CH_4) emissions, and use that data to estimate these emissions for the sources that are tested. Source test data would be used instead of default emission factors for estimating emissions. For the proposed regulation, the source test requirements have been strengthened over the current regulation, and it is consistent with the Western Climate Initiative proposal. Emission measurements must be performed in conformance with a facility source test plan submitted to the ARB and approved by the ARB Executive Officer.

Rationale for Section 95115(d).
This provision is included in the proposed regulation for those activities in which stakeholders showed that default emission factors may not accurately represent their actual facility emissions. The current ARB regulation for greenhouse gas reporting now allows the limited use of source test data. The option to use source testing is voluntary; therefore, reporters who prefer to use the other less costly methods within the regulation may do so.

Summary of Section 95115(e), Procedures for Biomass CO_2 Determination.
This provision requires the operator to follow the test procedure in 40 CFR §98.33(e)(3) to determine the biomass portion of CO_2 emissions for the combustion of municipal solid waste or any other fuel for which the biomass fraction is not known.

Rationale for Section 95115(e).
This provision is necessary to ensure the accurate quantification and categorization of fossil fuel and biomass-based CO_2 emissions from fuel combustion when the biomass fraction is not known. This requirement is needed because biomass CO_2 emissions are excluded in determining cap-and-trade compliance obligations, and they must therefore be separately identified and quantified.

Summary of Section 95115(f), Fuel Sampling.
This provision directs facilities which conduct fuel sampling and analysis to gather samples according to the frequencies in the U.S. EPA regulation, with two exceptions. Natural gas outside of pipeline quality would be sampled monthly, rather than semi-annually, and refinery fuel gas would be sampled daily, rather than daily or weekly. For facilities that do not have equipment in place to perform daily analysis of refinery fuel gas, this section requires that equipment be installed, and procedures established to perform daily sampling and analysis no later than January 1, 2013.

Rationale for Section 95115(f).
This provision is provided because WCI analysis found that natural gas outside of pipeline quality (as defined in section 95102), sometimes called field or associated gas, often has carbon content that is 10 to 15 percent different from pipeline gas. Because U.S. EPA has proposed to define natural gas very broadly, it is necessary to impose a

more frequent testing requirement to ensure carbon content is accurately represented in facility emissions The vast majority of facilities consuming natural gas will not be affected by this requirement. In addition refinery fuel gas would be sampled and tested, which is required in the current ARB regulation only for large refineries. Most facilities subject to this requirement of the proposed regulation already have the necessary equipment and procedures in place to meet it. For those that do not, the requirement is necessary to accurately quantify emissions from refinery fuel gas, which is a highly variable fuel. This accuracy is needed to support cap-and-trade and to ensure reporting consistency among similar fuel types. This approach is also consistent with the WCI design recommendations.

Summary of Section 95115(g), Electricity Generating and Cogeneration Units.
This provision requires reporting entities to report electricity generating and cogeneration unit information as required in section 95112, including generating capacity, power generated, thermal output, and other information for electricity generating and cogeneration units.

Rationale for Section 95115(g).
This provision is needed to effectively quantify and characterize the California power industry, as required by AB 32.

Summary of Section 95115(h), Natural Gas Provider.
This provision requires that those subject to the general stationary combustion requirements must report who provided natural gas to their facility, and the customer account number(s) used by the natural gas providers to identify the facility.

Rationale for Section 95115(h).
This provision is needed to provide a more accurate estimate of the GHG compliance obligations for gas suppliers. The collected data can be used to help reconcile the amount of natural gas associated to gas suppliers, providing better estimates, and a more robust cap-and-trade system.

Summary of Section 95115(i), Procedures for Missing Data.
This provision applies missing data procedures, specified and described in section 95129 of the regulation, to ensure data quality is sufficient for GHG inventory and cap-and-trade programs. It specifies what percentage of missing data an operator may use during a year before maximum alternate data must be used to substitute those missing values. In situations where reporters are not able to collect required data, the initial requirement is to complete the missing data with reasonable alternative data, which would tend to reflect the actual operating conditions. However, if substantial quantities of required data are missing, we provide a strong incentive for implementing corrective action. If the data capture rate is less than 80%, then reporters are required to use maximum daily values in place of the missing data.

Rationale for Section 95115(i).
This provision is needed to provide specific methods and protocols for estimating emissions when required data are incomplete. This helps to ensure that the emissions are not underestimated for the facility, and also makes it unfavorable for reporters to attempt reporting using incomplete data or false data. See the Summary and Rationale for subarticle 3, section 95129, for a full description of the missing data requirements.

Summary of Section 95115(j), Additional Data to Support Benchmarking.
This provision requires the reporting of additional data parameters to support benchmarking activities.

Rationale for Section 95115(j).
This provision is needed to allow ARB to collect and calculate data that will serve as the foundation for benchmarking activities. Benchmarking, as part of a cap-and-trade system, helps to protect trade-exposed industries from certain competitive disadvantages. Benchmarking also gives greater value to the most efficient entities, and rewards early actions to reduce emissions.

Summary of Section 95116, Glass Production.

This section specifies the overall greenhouse gas emissions reporting requirements and methods for the glass production industry.

Rationale for Section 95116.
This section is necessary because these facilities within California can produce significant levels of greenhouse gas emissions. In order to accurately quantify their greenhouse gas emissions, it is necessary to fully specify reporting requirements for the glass production sector. The proposed regulation text provides consistent and equitable reporting requirements and supports greenhouse gas cap-and-trade programs. In addition, this provision substantially harmonizes most ARB reporting requirements with U.S. EPA greenhouse gas reporting requirements for the sector, which helps to simplify reporting for those subject to the regulation.

Summary of Section 95116(a), CO_2 from Fossil Fuel Combustion.
This provision provides specific requirements for estimating CO_2 emissions for the industrial sector.

Rationale for Section 95116(a).
This provision is needed to require facilities subject to this part of the regulation to apply calculation methods that account for fuel carbon variability, which provides data of sufficient quality for cap-and-trade programs consistent with proposed WCI Harmonization Requirements. The requirement also allows use of Tier 1 estimation methods for de minimis sources and standardized fuels, which helps to simplify the reporting requirements where warranted.

Summary of Section 95116(b), Monitoring, Data, and Records.
This provision requires that monitoring, data, records, and other information collected or reported is consistent with the provisions of the CO_2 combustion method(s) used by the reporting entity in the previous section.

Rationale for Section 95116(b).
This provision is necessary to ensure complete, accurate, and credible GHG emissions data. This requirement for data collection and reporting helps to identify any data errors and greatly assists with the verification of GHG data reports for accuracy and completeness.

Summary of Section 95116(c), Procedures for Missing Data.
This provision specifies the procedures for the substitution of missing data for this industrial sector.

Rationale for Section 95116(c).
This provision is necessary because a primary goal of the reporting program is to collect accurate GHG emissions data in support of cap-and-trade. This helps to ensure that the emissions are not underestimated for the facility, and also makes it unfavorable for reporters to attempt to report using incomplete or false data.

Summary of Section 95116(c)(1), Procedures for Missing Data - Stationary Combustion and CEMS.
This provision identifies the missing data provisions in the regulation that must be followed for stationary combustion sources, and sources using CEMS. The provision refers to section 95129 of the regulation, which specifies these requirements for all combustion and CEMS sources.

Rationale for Section 95116(c)(1).
This provision is needed to specify how to substitute for missing data for combustion sources or sources using CEMS consistent with similar provisions applied in the requirements for other industrial sectors. Without this provision, missing data provisions would be ambiguous or unclear to the reporting entity. The specific provisions of section 95129 are addressed in the summary and rationale paragraphs for that section.

Summary of Section 95116(c)(2), Procedures for Missing Data – Carbonate-Based Raw Materials.
This provision describes what an operator is required to do when data are missing for the amounts of carbonate-based raw materials charged to any continuous glass melting furnace. The provision requires use of maximum data values if less than 80% of required data are available.

Rationale for Section 95116(c)(2).
This provision is necessary to provide direction to operators about what to do if they are missing required data for the amounts of carbonate-based raw materials charged to any continuous glass melting furnace. If this provision was not included, then inconsistent or inaccurate reporting would likely result. In addition, the provision helps to encourage

compliance and provides a strong incentive to maintain accurate and operational measurement systems.

Summary of Section 95116(c)(3), Procedures for Missing Data - Recordkeeping.
This provision requires that operators document the procedures used for estimates performed using missing data.

Rationale for Section 95116(c)(3).
This provision is necessary to ensure that required calculations are well documented so that the methods used, and the validity and accuracy of those methods, can be confirmed in the verification process.

Summary of Section 95116(d), Additional Data to Support Benchmarking.
This provision requires the reporting of additional data parameters to support benchmarking activities.

Rationale for Section 95116(d).
This provision is needed to allow ARB to collect and calculate data that will serve as the foundation for benchmarking activities. Benchmarking, as part of a cap-and-trade system, helps to protect trade-exposed industries from certain competitive disadvantages. Benchmarking also gives greater value to the most efficient entities, and rewards early actions to reduce emissions.

Summary of Section 95117, Lime Manufacturing.

This section specifies the overall greenhouse gas emissions reporting requirements and methods for the lime manufacturing industry.

Rationale for Section 95117.
This section is necessary because these facilities within California can produce significant levels of greenhouse gas emissions. In order to accurately quantify their greenhouse gas emissions, it is necessary to fully specify reporting requirements for the lime manufacturing sector. The proposed regulation text provides consistent and equitable reporting requirements and supports greenhouse gas cap-and-trade programs. In addition, this provision substantially harmonizes most ARB reporting requirements with U.S. EPA greenhouse gas reporting requirements for the sector, which helps to simplify reporting for those subject to the regulation.

Summary of Section 95117(a), CO_2 from Fossil Fuel Combustion.
This provision provides specific requirements for estimating CO_2 emissions for the industrial sector.

Rationale for Section 95117(a).
This provision is necessary because it requires facilities subject to this part of the regulation to apply calculation methods that account for fuel carbon variability, which provides data of sufficient quality for the cap-and-trade program consistent with

proposed WCI Harmonization Requirements. The requirement also allows use of Tier 1 estimation methods for de minimis sources and standardized fuels, which helps to simplify the reporting requirements where warranted.

Summary of Section 95117(b), Monitoring, Data, and Records.
This provision requires that monitoring, data, records, and other information collected or reported is consistent with the provisions of the CO_2 combustion method(s) used by the reporting entity in the previous section.

Rationale for Section 95117(b).
This provision is needed to ensure complete, accurate, and credible GHG emissions data. This requirement for data collection and reporting helps to identify any data errors and greatly assists with the verification of GHG data reports for accuracy and completeness.

Summary of Section 95117(c), Procedures for Missing Data.
This provision specifies the procedures for the substitution of missing data for the lime manufacturing sector.

Rationale for Section 95117(c).
This provision is necessary because a primary goal of the reporting program is to collect accurate GHG emissions data in support of cap-and-trade. This helps to ensure that the emissions are not underestimated for the facility, and also makes it unfavorable for operators to attempt to report using incomplete or false data.

Summary of Section 95117(c)(1), Procedures for Missing Data - Stationary Combustion and CEMS.
This provision identifies the missing data provisions in the regulation that must be followed for stationary combustion sources, and sources using CEMS. The provision refers to section 95129 of the regulation, which specifies these requirements for all combustion and CEMS sources.

Rationale for Section 95117(c)(1).
This provision is needed to specify how to substitute for missing data for combustion sources or sources using CEMS, consistent with similar provisions applied in the requirements for other industrial sectors. Without this provision, missing data provisions would be ambiguous or unclear to the reporting entity. The specific provisions of section 95129 are addressed in the summary and rationale paragraphs for that section.

Summary of Section 95117(c)(2), Procedures for Missing Data – CaO and MgO Content.
This provision applies missing data procedures for instances when CaO and MgO content data are missing and a new analysis cannot be undertaken. The provision requires use of maximum data values if less than 80% of required data are available or use of the highest quality assured value recorded during the given data year, as well as

the two previous data years if more than 80% but less than 90% of required data are available.

Rationale for Section 95117(c)(2).
This provision is necessary to provide direction to operators about what to do if they are missing required data for CaO and MgO content. If this provision was not included, then inconsistent or inaccurate reporting would likely result. In addition, the provision helps to encourage compliance, provides a strong incentive to maintain accurate and operational measurement systems, and encourages reporters to follow a robust sampling regime that includes backup sample collection.

Summary of Section 95117(c)(3),Procedures for Missing Data – Lime Produced and Lime Byproduct/Waste Produced and Sold.
This provision describes what an operator is required to do when data are missing for quantity of lime produced and quantity of lime byproduct/waste produced and sold. The provision requires use of maximum data values if less than 80% of required data are available.

Rationale for Section 95117(c)(3).
This provision is necessary to provide direction to operators about what to do if they are missing required data for quantity of lime produced and quantity of lime byproduct/waste produced and sold. If this provision was not included, then inconsistent or inaccurate reporting would likely result. In addition, the provision helps to encourage compliance and provides a strong incentive to maintain accurate and operational measurement systems.

Summary of Section 95117(c)(4), Procedures for Missing Data - Recordkeeping.
This provision requires that operators document the procedures used for estimates performed using missing data.

Rationale for Section 95117(c)(4).
This provision is necessary to ensure that required calculations are well documented so that the methods used, and the validity and accuracy of those methods, can be confirmed in the verification process.

Summary of Section 95118, Nitric Acid Production.

This section specifies the overall greenhouse gas emissions reporting requirements and methods for the nitric acid production industry.

Rationale for Section 95118.
This section is necessary because these facilities within California can produce significant levels of greenhouse gas emissions. In order to accurately quantify their greenhouse gas emissions, it is necessary to fully specify reporting requirements for the nitric acid production sector. The proposed regulation text provides consistent and equitable reporting requirements and supports greenhouse gas cap-and-trade

programs. In addition, this provision substantially harmonizes most ARB reporting requirements with U.S. EPA greenhouse gas reporting requirements for the sector, which helps to simplify reporting for those subject to the regulation.

Summary of Section 95118(a), CO_2 from Fossil Fuel Combustion.
This provision provides specific requirements for estimating CO_2 emissions for the industrial sector.

Rationale for Section 95118(a).
This provision is necessary because it requires facilities subject to this part of the regulation to apply calculation methods that account for fuel carbon variability, which provides data of sufficient quality for the cap-and-trade program consistent with proposed WCI Harmonization Requirements. The requirement also allows use of Tier 1 estimation methods for de minimis sources and standardized fuels, which helps to simplify the reporting requirements where warranted.

Summary of Section 95118(b), Monitoring, Data, and Records.
This provision requires that monitoring, data, records, and other information collected or reported is consistent with the provisions of the CO_2 combustion method(s) used by the reporting entity in the previous section.

Rationale for Section 95118(b).
This provision is necessary to ensure complete, accurate, and credible GHG emissions data. This requirement for data collection and reporting helps to identify any data errors and greatly assists with the verification of GHG data reports for accuracy and completeness.

Summary of Section 95118(c), Procedures for Missing Data.
This provision specifies the procedures for the substitution of missing data for this industrial sector.

Rationale for Section 95118(c).
This provision is necessary because a primary goal of the reporting program is to collect accurate GHG emissions data in support of cap-and-trade. This helps to ensure that the emissions are not underestimated for the facility, and also makes it unfavorable for operators to attempt to report using incomplete or false data.

Summary of Section 95118(c)(1), Procedures for Missing Data - Stationary Combustion and CEMS.
This provision identifies the missing data provisions in the regulation that must be followed for stationary combustion sources, and sources using CEMS. The provision refers to section 95129 of the regulation, which specifies these requirements for all combustion and CEMS sources.

Rationale for Section 95118(c)(1).
This provision is needed to specify how to substitute for missing data for combustion sources or sources using CEMS, consistent with similar provisions applied in the requirements for other industrial sectors. Without this provision, missing data provisions would be ambiguous or unclear to the reporting entity. The specific provisions of section 95129 are addressed in the summary and rationale paragraphs for that section.

Summary of Section 95118(c)(2), Procedures for Missing Data – Nitric Acid Production.
This provision describes what an operator is required to do when data are missing for nitric acid production. The provision requires use of maximum data values if less than 80% of required data are available.

Rationale for Section 95118(c)(2).
This provision is necessary to provide direction to operators about what to do if they are missing required data for nitric acid production. If this provision was not included, then inconsistent or inaccurate reporting would likely result. In addition, the provision helps to encourage compliance and provides a strong incentive to maintain accurate and operational measurement systems.

Summary of Section 95118(c)(3), Procedures for Missing Data - Recordkeeping.
This provision requires that operators document the procedures used for estimates performed using missing data.

Rationale for Section 95118(c)(3).
This provision is necessary to ensure that required calculations are well documented so that the methods used, and the validity and accuracy of those methods, can be confirmed in the verification process.

Summary of Section 95119, Pulp and Paper Manufacturing.

Summary of Section 95119.
This section specifies the overall greenhouse gas emissions reporting requirements and methods for the pulp and paper industry, which can produce significant levels of greenhouse gas emissions in California.

Rationale for Section 95119.
This provision is included to ensure accurate greenhouse emissions reporting by fully specifying reporting requirements for the pulp and paper manufacturing sector. The proposed regulation text provides consistent and equitable reporting requirements and supports the cap-and-trade program. In addition, the proposed regulation for pulp and paper manufacturing uses the U.S. EPA reporting requirements for pulp and paper manufacturing as its basis. This approach substantially harmonizes the proposed ARB reporting requirements with U.S. EPA greenhouse gas reporting requirements for the sector, which simplifies reporting and reduces costs for those subject to the regulation.

Summary of Section 95119(a), CO_2 from Fossil Fuel Combustion.
This provision specifies requirements for estimating CO_2 emissions for combustion emissions from this industrial sector. The provision refers to section 95115 of the regulation, which specifies on the basis of fuel type and unit size which U.S. EPA methods may be selected for calculating emissions of CO_2 from combustion.

Rationale for Section 95119(a).
This provision is needed to provide data quality sufficient for the cap-and-trade program and consistent with combustion emissions methods required in other industrial sectors. The limitations in section 95115 on selection of an appropriate calculation method are designed to account for fuel carbon variability, which will ensure accurate emissions estimation for combustion, the largest and most important source of overall emissions.

Summary of Section 95119(b), Monitoring, Data, and Records.
This provision requires that monitoring, data, records, and the other information collected or reported are consistent with the provisions of the CO_2 combustion method(s) used by the reporting entity in the previous section.

Rationale for Section 95119(b).
This provision is needed to ensure complete and accurate GHG combustion emissions data are collected by the reporting entity and retained for verification purposes. Because it will help ensure that data are properly collected and that errors can be corrected, the provision is critical for the credibility of the information that becomes the basis of emissions trading.

Summary of Section 95119(c), Procedures for Missing Data - General.
This provision specifies the procedures for the substitution of missing data for this industrial sector.

Rationale for Section 95119(c).
This provision is necessary because a primary goal of the reporting program is to collect accurate GHG emissions data in support of cap-and-trade. This helps to ensure that the emissions are not underestimated for the facility, and also makes it unfavorable for operators to attempt to report using incomplete or false data.

Summary of Section 95119(c)(1), Procedures for Missing Data - Stationary Combustion and CEMS.
This provision identifies the missing data provisions in the regulation that must be followed for stationary combustion sources, and sources using CEMS. The provision refers to section 95129 of the regulation, which specifies these requirements for all combustion and CEMS sources.

Rationale for Section 95119(c)(1).
This provision is needed to specify how to substitute for missing data for combustion sources or sources using CEMS, consistent with similar provisions applied in the requirements for other industrial sectors. Without this provision, missing data provisions

would be ambiguous or unclear to the reporting entity. The specific provisions of section 95129 are addressed in the summary and rationale paragraphs for that section.

Summary of Section 95119(c)(2), Procedures for Missing Data - Makeup Chemicals.
This provision provides direction to operators about what to do if they are missing required data for makeup chemicals (carbonates).

Rationale for Section 95119(c)(2).
This provision is necessary to provide direction to reporters about what to do if they are missing required data for makeup chemicals (carbonates). If this provision were not included, there would be uncertainty for reporters and inconsistent and inaccurate reporting if required data are not available. In addition, the provision helps to encourage compliance by requiring maximum values to be used if less than 80% of required data are available.

Summary of Section 95119(c)(3), Procedures for Missing Data - Recordkeeping.
This provision requires that operators document the procedures used for estimates performed using missing data.

Rationale for Section 95119(c)(3).
This provision is necessary to ensure that required calculations are well documented so that the methods used, and the validity and accuracy of those methods, can be confirmed in the verification process.

Summary of Section 95110(d), Additional Data to Support Benchmarking.
This provision requires the reporting of additional data parameters to support benchmarking activities.

Rationale for Section 95110(d).
This provision is needed to allow ARB to collect and calculate data that will serve as the foundation for benchmarking activities. Benchmarking, as part of a cap-and-trade system, helps to protect trade-exposed industries from certain competitive disadvantages. Benchmarking also gives greater value to the most efficient entities, and rewards early actions to reduce emissions.

Summary of Section 95120, Iron and Steel Production.

This section specifies the overall greenhouse gas emissions reporting requirements and methods for iron and steel production.

Rationale for Section 95120.
These facilities within California can produce significant levels of greenhouse gas emissions. In order to accurately quantify their greenhouse emissions it is necessary to fully specify reporting requirements for the iron and steel production sector. The proposed regulation text provides consistent and equitable reporting requirements and supports greenhouse gas cap-and-trade programs. In addition, the proposed regulation

for iron and steel manufacturing uses the U.S. EPA reporting requirements for iron and steel as its basis. This approach substantially harmonizes the proposed ARB reporting requirements with U.S. EPA greenhouse gas reporting requirements for the sector, which simplifies reporting and reduces costs for those subject to the regulation.

Summary of Section 95120(a), CO_2 from Fossil Fuel Combustion.
This provision specifies requirements for estimating CO_2 emissions for combustion emissions from this industrial sector. The provision refers to section 95115 of the regulation, which specifies on the basis of fuel type and unit size which U.S. EPA methods may be selected for calculating emissions of CO_2 from combustion.

Rationale for Section 95120(a).
This provision is needed to provide data of sufficient quality for the cap-and-trade program and consistent with combustion emissions methods required in other industrial sectors. The limitations in section 95115 on selection of an appropriate calculation method are designed to account for fuel carbon variability, which will ensure accurate emissions estimation for combustion, the largest and most important source of overall emissions.

Summary of Section 95120(b), Monitoring, Data, and Records.
This provision requires that monitoring, data, records, and the other information collected or reported are consistent with the provisions of the CO_2 combustion method(s) used by the operator in the previous section.

Rationale for Section 95120(b).
This provision is needed to ensure complete and accurate GHG combustion emissions data are collected by the reporting entity and retained for verification purposes. Because it will help ensure that data are properly collected and that errors can be corrected, the provision is critical for the credibility of the information that becomes the basis of emissions trading.

Summary of Section 95120(c), Procedures for Missing Data.
This provision specifies the procedures for the substitution of missing data for this industrial sector.

Rationale for Section 95120(c).
This provision is necessary because a primary goal of the reporting program is to collect accurate GHG emissions data in support of cap-and-trade. This helps to ensure that the emissions are not underestimated for the facility, and also makes it unfavorable for operators to attempt to report using incomplete or false data.

Summary of Section 95120(c)(1), Procedures for Missing Data - Stationary Combustion and CEMS.
This provision identifies the missing data provisions in the regulation that must be followed for stationary combustion sources, and sources using CEMS. The provision

refers to section 95129 of the regulation, which specifies these requirements for all combustion and CEMS sources.

Rationale for Section 95120(c)(1).
This provision is needed to specify how to substitute for missing data for combustion sources or sources using CEMS, consistent with similar provisions applied in the requirements for other industrial sectors. Without this provision, missing data provisions would be ambiguous or unclear to the reporting entity. The specific provisions of section 95129 are addressed in the summary and rationale paragraphs for that section.

Summary of Section 95120(c)(2), Procedures for Missing Data – Carbon-Containing Inputs or Outputs.
This provision describes what an operator is required to do when data are missing for the carbon-containing inputs or outputs. The provision requires use of maximum data values if less than 80% of required data are available.

Rationale for Section 95120(c)(2).
This provision is necessary to provide direction to reporters about what to do if they are missing required data for carbon-containing inputs or outputs. If this provision was not included, inconsistent or inaccurate reporting would likely result. In addition, the provision helps to encourage compliance and provides a strong incentive to maintain accurate and operational measurement systems.

Summary of Section 95120(c)(3), Procedures for Missing Data - Recordkeeping.
This provision requires that operators document the procedures used for estimates performed using missing data.

Rationale for Section 95120(c)(3).
This provision is necessary to ensure that required calculations are well documented so that the methods used, and the validity and accuracy of those methods, can be confirmed in the verification process.

Summary of Section 95120(d), Additional Data to Support Benchmarking.
This provision requires the reporting of additional data parameters to support benchmarking activities.

Rationale for Section 95120(d).
This provision is needed to allow ARB to collect and calculate data that will serve as the foundation for benchmarking activities. Benchmarking, as part of a cap-and-trade system, helps to protect trade-exposed industries from certain competitive disadvantages. Benchmarking also gives greater value to the most efficient entities, and rewards early actions to reduce emissions.

Summary of Section 95121, Suppliers of Transportation Fuels.

This section specifies the overall greenhouse gas emissions reporting requirements and methods for suppliers of transportation fuels identified under the applicability section of

this regulation. Suppliers are identified as refiners, position holders, enterers and biomass-derived fuel producers for transportation fuels, and refiners for liquefied petroleum gas (LPG).

Rationale for Section 95121.
This section is necessary because these suppliers put on the market fuels that are the single largest source of greenhouse gas emissions in California. In order to accurately quantify their greenhouse gas emissions it is necessary to fully specify reporting requirements for the industry sector. The proposed regulation text provides consistent and equitable reporting requirements and supports greenhouse gas cap-and-trade programs. In addition, the transportation fuels section was written with substantial input from the regulated parties to harmonize most ARB reporting requirements with California Board of Equalization fuel reporting requirements and to facilitate verification of a vast and complex sector, which helps to simplify reporting and verification for those subject to the rule. The LPG section was written to harmonize with the U.S. EPA greenhouse gas reporting requirements. Refiners are required to report the volume and emissions for LPG to be consistent with the cap-and-trade program requirement that suppliers of LPG are covered entities.

Section 95121(a), GHGs to Report.

Summary for Section 95121(a)(1).
This provision specifies that refiners must report CO_2, CH_4, N_2O and CO_2e emissions from the combustion or oxidation of LPG supplied in California.

Rationale for Section 95121(a)(1).
This provision is necessary to clearly define the scope of GHGs that refiners subject to this part of the regulation are required to report. This provision is ensure there is sufficient data for the cap-and-trade program consistent with all other industrial sectors.

Summary for Section 95121(a)(2).
This provision specifies that refiners, position holders, enterers, and producers of biomass-derived fuels will report CO_2, CH_4, N_2O, CO_2 from biomass-derived fuels and CO_2e emissions from the combustion or oxidation of fossil and biomass-derived fuels supplied in California. The fuels required to be reported are listed in Tables MM-1 and MM-2 of 40 CFR Part 98. Fuels are not reported as finished fuels, but as the blendstock plus any additional components.

Rationale for Section 95121(a)(2).
This provision is necessary to clearly define the scope of GHGs that refiners, position holders, enterers, and producers of biomass-derived fuels subject to this part of the regulation are required to report and to provide sufficient data for the cap-and-trade program consistent with all other industrial sectors. In order to facilitate reporting, refiners, position holders and enterers of both fossil and biomass-derived fuels were selected as the point of regulation. These entities were selected as the point of regulation because they currently report almost the same data to the California Board of

Equalization and it facilitates tracking of fuel that leaves the state. Producers of biomass-derived fuels are included to track the growth in usage, to allow ARB to monitor the success of reduction strategies, and ensure rigorous, and constant emissions accounting. To be consistent with the U.S. EPA MRR, the fuels selected for regulation were the fuels listed in 40 CFR 98 Tables MM-1, and MM-1, except that it was determined that Distillate Fuel Oil would be limited to Distillate Fuel Oil #1 and Distillate Fuel Oil #2. The other Distillate Fuel Oils are not significant contributors to transportation emissions in California.

Summary for Section 95121(b), Calculating GHG Emissions.
This provision requires suppliers to apply calculation methods that use fuel specific emission factors that take into account grade and seasonable variability. The use of a Tier 1 or simplified Tier 1 methodology helps to simplify the reporting requirements without sacrificing accuracy. CO_2e emissions are calculated by summing the products of CO_2, CH_4, and N_2O mass emissions and their respective global warming potentials.

Rationale for Section 95121(b).
This provision is necessary to identify the calculation methods required for suppliers subject to this provision of the regulation. Suppliers are required to calculate CO_2, CH_4, N_2O and CO_2 from biomass-derived fuels using a Tier 1 (Volume * High Heat Value * Default Emission Factor) or a simplified Tier 1 (Volume * Default Emission Factor) to calculate emissions. It was determined by staff that the variations in fuel composition were minimal, due to existing fuels regulations, enabling default emission factors to provide the accuracy required for cap and trade. LPG emissions are calculated by summing the emission from its individual components. Biomass-derived CO_2 is not summed for CO_2e emissions because verified or certified biomass-derived fuels will not have a compliance obligation. But CH_4 and N_2O from biomass-derived fuel combustion or oxidation is summed for CO_2e emissions.

Summary of Section 95121(c), Monitoring and QA/QC Requirements.
This provision requires suppliers to follow the monitoring and QA/QC requirements of the U.S. EPA Greenhouse Gas Mandatory Reporting Rule. Position holders are exempted from meter calibration requirements if: (1) the supplier does not operate the meter, (2) the fuel meter is used by other companies that do not share common ownership, or (3) the meter is regulated by the county weights and measures department or equivalent. This provision also specified the standard temperatures and pressures for reporting volumes of each of the regulated fuels.

Rationale for Section 95121(c).
This provision is necessary to ensure complete, accurate, and credible GHG emissions data. This requirement for data collection and reporting helps to identify any data errors and greatly assists with the verification of GHG data reports for accuracy and completeness. Staff believes that all meters used at the terminal rack are certified by the county weights and measures, attesting to their accuracy. All meters at the rack are also used for financial transactions and staff believes that these two factors attest to the accuracy of terminal rack meters, thus relieving reporting entities of the need to prove

calibration. Industry standard temperatures and pressures, that also conform with the U.S. EPA greenhouse gas reporting requirements, are used to standardize and facilitate reporting.

Section 95121(d), Data Reporting Requirements.

Summary of Section 95121(d)(1).
This provision requires position holders to report the annual fuel volumes, in barrels, delivered at the rack for California delivery. The volume reported will be the volumes measured and reported to the position holder by the terminal operator. The position holder will individually report the fuels listed in 40 CFR 98 Tables MM-1 and MM-2 and emissions from the complete combustion or oxidation of those fuels.

Rationale for Section 95121(d)(1).
This provision is necessary to clearly identify the fuels to report and the point of regulation and data collection for position holders.

Summary of Section 95121(d)(2).
This provision requires refiners and position holder who are also terminal operators to report the annual fuel volumes, in barrels, delivered at the rack for California delivery. The volume reported will be the volumes measured at the rack. The position holder or refiner will individually report the fuels listed in 40 CFR 98 Tables MM-1 and MM-2 and emissions from the complete combustion or oxidation of those fuels.

Rationale for Section 95121(d)(2).
This provision is necessary to clearly identify the fuels to report and the point of regulation and data collection for refiners and position holders.

Summary for section 95121(d)(3).
This provision requires refiners to report the annual fuel volumes, in barrels, delivered via the bulk transfer system to entities not licensed by the California Board of Equalization as a fuel supplier. The volumes reported will be the actual volumes delivered based on contracts or metered volumes. The refiner will individually report the fuels listed in 40 CFR 98 Tables MM-1 and MM-2 and emissions from the complete combustion or oxidation of those fuels.

Rationale for Section 95121(d)(3).
This provision is necessary to accurately account for all fuel in the bulk transfer system that is not delivered to a position holder or across the rack.

Summary of Section 95121(d)(4).
This provision requires enterers to report the annual fuel volumes, in barrels, imported into California for delivery. The volume reported will be the volumes reflected in the bill of lading or other shipping documents. The enterer will individually report the fuels listed in 40 CFR 98 Tables MM-1 and MM-2 and emissions from the complete combustion or oxidation of those fuels.

Rationale for Section 95121(d)(4).
This provision is necessary to clearly identify the fuels to report and the point of regulation and data collection for enterers

Summary of Section 95121(d)(5).
This provision requires producers of biomass-derived fuels to report the annual fuel volumes, in barrels, supplied for California delivery. The volume reported will be the volumes measured at a custody transfer meter or listed on a bill of lading. The producer will individually report the fuels listed in 40 CFR 98 Tables MM-1 and MM-2 and emissions from the complete combustion or oxidation of those fuels. If the exact same data is reported under the Low Carbon Fuel Standard regulation the producer will not have to report under this proposed regulation.

Rationale for Section 95121(d)(5).
This provision is necessary to clearly identify the fuels to report and the point of regulation and data collection for biomass-derived fuel producers. Producers of biomass-derived fuels are included to track the growth in usage, to allow us to monitor the success of reduction strategies, and ensure rigorous and constant emissions accounting. If data sufficient for ARB to calculate emission from biomass-derived fuels is reported to ARB via the Low Carbon Fuel Standard regulation, the producers will not have to additionally report under mandatory reporting.

Summary for Section 95121(d)(6).
This provision requires biomass derived-fuel producers to identify the source of any fossil fuels blended with biomass-derived fuels.

Rationale for Section 95121(d)(6).
This provision is necessary to account for all fossil fuels combusted in California. This is to determine if fossil fuels blended by biomass-derived fuel producers are captured by other provisions of this regulation or are unregulated.

Summary for Section 95121(d)(7).
This provision requires refineries to report the volume, in barrels, of liquefied petroleum gas supplied in California, as well as the volumes of the individual components.

Rationale for Section 95121(d)(7).
This provision is necessary to clearly identify that refiners must report LPG volumes.

Summary for Section 95121(d)(8).
This provision requires all fuel suppliers to report CO_2, N_2O, CH_4, CO_2 from biomass-derived fuels, and CO_2e from the complete combustion or oxidation of the supplied fuel. The calculation methodologies are described in 95121(b).

Rationale for Section 95121(d)(8).
This provision is necessary for require reporting of fuel emissions as specified in 95121(b).

Summary for Section 95121(d)(9).
Enterers and biomass-derived fuel producers that deliver fuel to position holders at terminals must identify the recipient of the delivered fuel.

Rationale for Section 95121(d)(9).
This provision is necessary to avoiding double counting of emissions.

Summary of Section 95121(e), Procedures for Missing Data.
This provision sets forth missing data procedures to ensure data quality is sufficient for GHG inventory and cap-and-trade programs. It specifies that suppliers must follow the missing data procedures of the U.S. EPA Greenhouse Gas Mandatory Reporting Rule

Rationale for Section 95121(e).
This provision is necessary to collect accurate GHG emissions data. In situations where reporters are not able to collect required data, reporters are required to use standard billing practices to replace missing data. These methods will provide the most accurate data possible in these situations.

Summary of Section 95122, Suppliers of Natural Gas, Natural Gas Liquids, and Liquefied Petroleum Gas.

This provision specifies the overall greenhouse gas emissions reporting requirements and methods for suppliers of natural gas, natural gas liquids and liquefied petroleum gas identified under the applicability section of this regulation. Natural gas suppliers include public utility gas corporations and publicly owned natural gas utilities which are both considered local distribution companies (LDC) under this regulation, and interstate and intrastate natural gas pipelines. Liquefied petroleum gas (LPG) suppliers are natural gas liquid (NGL) fractionators and LPG consignees that import LPG into California.

Rationale for Section 95122.
These suppliers within California put on the market fuels that when combined are one of the largest sources of greenhouse gas emissions. In order to accurately quantify their greenhouse gas emissions it is necessary to fully specify reporting requirements for this industry sector. The proposed regulation text provides consistent and equitable reporting requirements and supports greenhouse gas cap-and-trade programs. In addition, this provision was written with substantial input from the regulated parties to harmonize most ARB reporting requirements with U.S. EPA greenhouse gas reporting requirements for fuel reporting requirements for the sector and to facilitate verification of a vast and complex sector, which helps to simplify reporting for those subject to the regulation. Natural gas suppliers were expanded to include interstate and intrastate pipelines as sources to get a complete picture of natural gas usage in the state. LPG

consignees were added because the U.S. EPA greenhouse gas reporting requirements did not include domestic LPG importers into California. In order to be consistent with the requirement of the cap-and-trade regulation to include all LPG suppliers in California as covered entities, consignees were added.

Section 95122(a), GHG's to Report.

Summary of Section 95122(a)(1).
This provision adds CH_4, N_2O, and CO_2e emission to the CO_2 emissions natural gas liquid fractionators are required to report from the complete combustion or oxidation of liquefied petroleum gas supplied in California.

Rationale for Section 95122(a)(1).
This provision is necessary to clearly define the scope of GHGs that natural gas liquid fractionators subject to this part of the regulation are required to report in order to provide sufficient data for the cap-and-trade program consistent with all other industrial sectors.

Summary for Section 95122(a)(2).
This provision adds CH_4, N_2O, CO_2 from biomass-derived fuels, and CO_2e emissions to the CO_2 emissions local distribution companies are required to report from the complete combustion or oxidation of natural gas supplied in California.

Rationale for Section 95122(a)(2).
This provision is necessary to clearly define the scope of GHGs that local distribution companies subject to this part of the regulation are required to report and to provide sufficient data for the cap-and-trade program consistent with all other industrial sectors.

Summary of Section 95122(a)(3).
This provision specified that consignees for liquefied petroleum gas will report CO_2, CH_4, N_2O, and CO_2e emissions from the complete combustion or oxidation of liquefied petroleum gas supplied in California.

Rationale for Section 95122(a)(1).
This provision is necessary to clearly define the scope of GHGs that consignees for liquefied petroleum gas subject to this part of the regulation are required to report and to provide sufficient data for the cap-and-trade program consistent with all other industrial sectors.

Section 95122(b), Calculating GHG Emissions.

Summary of Section 95122(b)(1).
This provision directs natural gas liquid fractionators to use a Tier 1 (Volume * High Heat Value * Default Emission Factor) or modified Tier 1 (Volume * Default Emission Factor) methodology for calculating emission from liquefied petroleum gas. The emission are summed for the individual components. Emission factors and/or heating

values for any components not listed in 40 CFR 98 Table NN-1 will be taken from Tables MM-1 or C-1

Rationale for Section 95122(b)(1).
This provision is necessary to describe the methods natural gas liquid fractionators will use to estimate CO_2 emissions from the liquefied petroleum gas supplied.

Summary of Section 95122(b)(2).
This provision directs local distribution companies (LDC) to use a Tier 2 (Volume * Annual Average High Heat Value * Default Emission Factor) methodology or modified Tier 2 (Volume * Annual Average Emission Factor) methodology to calculate emission from the pipeline quality natural gas supplied. In either case the reported specific HHV will be used for calculating emissions. For the modified Tier 2 methodology the emission factor will be the product of the reporter specific HHV and the default emission factor from 40 CFR 98 Table NN-1. The LDC will conduct a mass balance around their system with inputs from the city gate, or state boarder, in-state production and storage, and outputs to storage. All other outputs including outputs to other LDCs or customers with greater than or equal to 460,000 Mscf, will be reported and netted out as appropriate by ARB. For natural gas outside the range of 970-1100 the operator will use a Tier 3 (carbon content based) methodology with monthly carbon content testing for estimating emissions. The Tier 3 method will replace the Tier 2 methods as appropriate to estimate emissions.

Rationale for Section 95122(b)(2).
This provision is necessary to describe the methods local distribution companies will use to estimate CO_2 emissions from the natural gas supplied.

Summary of Section 95122(b)(3).
This provision directs natural gas liquid fractionators and LDC to estimate and report CH_4 and N_2O emissions for all fuel supplied according to the methods in 40 CFR 98.33(c)(1)

Rationale for Section 95122(b)(3).
This provision is necessary to describe the methods natural gas liquid fractionators and local distribution companies will use to estimate CH_4 and N_2O emissions from the natural gas supplied.

Summary of Section 95122(b)(4).
This provision directs LCDs to calculate system wide CH_4, N_2O, CO_2 from biomass-derived fuels and CO_2e emissions from the natural gas supplied.

Rationale for Section 95122(b)(4).
This provision is necessary to describe the methods local distribution companies will use to estimate CH_4, N_2O, CO_2 from biomass-derived fuels and CO_2e system wide emissions from the natural gas supplied.

Summary of Section 95122(b)(5).
This provision directs consignees (importers) of liquefied petroleum gas (LPG) to use a modified Tier 1 (Volume * Default Emission Factor) methodology for calculating emission from the liquefied petroleum gas supplied. If compositional analysis of the fuel is available it must be used otherwise the default LPG emission factor from 40 CFR 98 Table C-1 is used. The emission are summed for the individual components, and emission factors for any components not listed in 40 CFR 98 Table NN-1 will be taken from Tables MM-1 or C-1

Rationale for Section 95122(b)(5).
This provision is necessary to describe the methods consignees will use to estimate CO_2 emissions from the liquefied petroleum gas supplied.

Summary of Section 95122(b)(6).
This provision directs consignees of LPG to estimate and report CH_4 and N_2O emissions for all fuel supplied as described in 40 CFR 98.33(c)(1).

Rationale for Section 95122(b)(6).
This provision is necessary to describe the methods consignees will use to estimate CH_4 and N_2O emissions from the liquefied petroleum gas supplied.

Summary of Section 95122(b)(7).
This provision directs all fuel suppliers to calculate the carbon dioxide equivalent emissions of the fuel supplied by summing the products of the metric tons of individual GHG emissions and their respective global warming potentials.

Rationale for Section 95122(b)(7).
This provision is necessary to describe the method for calculating the CO_2e emissions from the CO_2, CH_4 and N_2O emissions for all fuels supplied.

Summary of Section 95122(c), Monitoring and QA/QC Requirements.
This provision requires suppliers to follow the monitoring and QA/QC requirements of the U.S. EPA Mandatory Reporting Rule. Natural gas suppliers and NGL fractionators are required to measure and record monthly values for volumes, composition, and HHV where required, and LPG consignees are required to record shipment volumes and compositions, if supplied. LPG volumes are corrected to 60 degrees Fahrenheit.

Rationale for Section 95122(c).
This provision is necessary to ensure complete, accurate, and credible GHG emissions data. This requirement for data collection and reporting helps to identify any data errors and greatly assists with the verification of GHG data reports for accuracy and completeness. Frequencies for measurement of fuel analytical data are not always specifically spelled out in the regulation, and from staff's understanding, are often measured at a much higher frequency than monthly; however, staff believes that monthly measurements will provide sufficient accuracy for cap-and-trade.

Section 95122(d), Data Reporting Requirements.

Summary of Section 95122(d)(1).
This provision adds the volume of liquefied petroleum gas supplied in California to the fuels natural gas liquid fractionators are required to report. It also specifies that CO_2, CH_4, N_2O and CO_2e emissions from the complete combustion or oxidation of the volumes supplied must be reported.

Rationale for Section 95122(d)(1).
This provision is necessary to clearly identify the fuels and emissions that natural gas liquid fractionators are required to report.

Summary of Section 95122(d)(2).
This provision requires local distribution companies to provide data additional to the U.S. EPA MRR. Additional reporting requirements include reporting of CH_4, N_2O, CO_2 from biomass-derived fuels, and CO_2e emissions, and data to aid in verification and netting out of natural gas delivered to covered entities.

Rationale for Section 95122(d)(2).
This provision is necessary to clearly identify the emissions local distribution companies are required to report. This provision also collects additional information to aid in both verification and netting out of natural gas deliveries to capped entities. Natural gas deliveries need to be netted out because the compliance obligation for the fuel will be calculated at the facility.

Summary for section 95122(d)(3).
This provision requires interstate pipelines to report customers information on all their in-state customers.

Rationale for Section 95122(d)(4).
This provision is necessary because the cap-and-trade regulation does not include interstate pipelines as a covered entity, and ARB needs to understand the volume of fuel that may go uncapped.

Summary for Section 95122(d)(4).
This provision requires intrastate pipelines to report as a local distribution company. Intrastate pipelines, instead of using the city gate, will report receipts from interconnects with LDCs, interstate pipelines or other intrastate pipelines as the city gate.

Rational for Section 95122(d)(4).
This provision is necessary because intrastate pipelines are not included in the U.S. EPA MRR. Since reporting requirements are not specified by the U.S. EPA, intrastate pipelines are instructed to use the same reporting methodologies as local distribution companies, with the exception of the city gate as described above. Including them is consistent with the desire of ARB to require reporting for the vast majority of natural gas deliveries in California.

Summary for Section 95122(d)(5).
This provision requires consignees of liquefied petroleum gas to report the volume of LPG, volume of components, if known, and CO_2, CH_4, N_2O and CO_2e emissions for liquefied petroleum gas supplied in California.

Rationale for section 95122(d)(5).
This provision in necessary because the U.S. EPA MRR does not include reporting requirements for entities that import liquefied petroleum gas into California from other domestic sources. This provision specifies what must be reported as well as the methodologies used to report emissions.

Summary of Section 95122(e), Procedures for Missing Data.
This provision applies missing data procedures to ensure data quality is sufficient for a GHG inventory and the cap-and-trade program. It specifies that suppliers must follow the missing data procedures of the U.S. EPA Mandatory Reporting Rule

Rationale for Section 95122(e).
The goal of the reporting program is to collect accurate GHG emissions data. In situations where reporters are not able to collect required data, reporters are required to use standard billing practices to replace missing data. These methods will provide the most accurate data possible in this situation.

Summary of Section 95123, Suppliers of Carbon Dioxide.

This section specifies the GHG reporting requirements and methodologies for suppliers of carbon dioxide.

Rationale for Section 95123.
This section is necessary because, while CO_2 capture and sequestration now occur on a small scale, data concerning the transfer of CO_2 are required to evaluate methods which may remove, rather than emit, CO_2 produced and recovered in industries from combustion and process sources.

Summary of Section 95123(a).
This provision defines which California based facilities must report as suppliers of carbon dioxide:

1. all producers of CO_2;
2. importers of CO_2 with annual bulk imports of N_2O, fluorinated GHG, and CO_2 that in combination are equivalent to 25,000 metric tons of CO_2e or more; and
3. exporters of CO_2 with annual bulk exports of N_2O, fluorinated GHG, and CO_2 that in combination are equivalent to 25,000 metric tons of CO_2e or more.

Rationale for Section 95123(a).
This provision is necessary to identify which suppliers of CO_2 are required to report under the regulation.

Summary of Section 95123(b).
This provision establishes missing data substitution procedures which must be used to replace missing data.

Rationale for Section 95123(b).
This provision is necessary to provide a strong incentive for reporters to generate as complete a data set as possible, while specifying how to generate substitution data in circumstances where data was unavoidably lost.

Summary of Section 95123(b)(1).
This provision establishes missing data requirements for stationary combustion emissions.

Rationale for Section 95123(b)(1).
This provision is to ensure that all reporters use the same methodology to report missing data. Consistent missing data requirements for all stationary combustion are necessary to ensure industry wide data consistency.

Summary of Section 95123(b)(2).
This provision establishes missing data requirements for all other GHG data which CO_2 suppliers are required to report.

Rationale for Section 95123(b)(2).
This provision is necessary to ensure data consistency across all California CO_2 suppliers.

Subarticle 3
Additional Requirements for Reported Data

Repeal of Previous Section 95125.

Section 95125 of the current regulation provides various GHG emission estimation methods and calculations required for reporting. The proposed regulation would repeal section 95125.

Rationale for Repeal of Section 95125.
Section 95125 is no longer necessary because emission estimation and other requirements are now included in sector-specific reporting requirements, the revised section 95115 for stationary fuel combustion sources, and other sections of the proposed regulation.

Summary of Section 95129, Substitution for Missing Data Used to Calculate Emissions from Stationary Combustion and CEMS Sources.

This section prescribes methods and procedures for estimating emissions if the data required for calculating emissions are missing.

Rationale for Section 95129.
These provisions are necessary for creating incentives for operators to achieve high data capture rates, and at the same time, preventing gaming of the cap-and-trade system. In assessing the suitability of the U.S. EPA reporting rule for cap-and-trade, it became apparent that many of the U.S. EPA provisions for missing data substitution could potentially be subject to abuse and are not sufficient for cap-and-trade purposes. See Section II.C of this document for a more detailed discussion of the weaknesses of U.S. EPA provisions.

Emissions are either measured directly by CEMS or calculated from measured fuel data. In practice, because measurement equipment and fuel sampling systems may occasionally malfunction, additional requirements to address missing data are necessary to ensure the parameters used to estimate emissions are fully accounted. If some of these required data are missing, emissions can be underestimated, resulting in the reporting entity being responsible for a smaller compliance obligation and creating a perverse incentive to miss more data. This can open up opportunities for gaming the cap-and-trade system. For these reasons, a regulatory prescription for how to substitute for missing data is imperative to ensure the integrity of the carbon market.

Summary of Section 95129(a), Missing Data Substitution Procedures for Units Reporting Under 40 CFR Part 75.
This provision directs operators of 40 CFR Part 75 units to follow the missing data substitution procedures in 40 CFR Part 75, which is consistent with the U.S. EPA rule.

Rationale of Section 95129(a).
This provision is necessary for maintaining consistency with the U.S. EPA GHG reporting rule.

Summary of Section 95129(b), Missing Data Substitution Procedures for Other Units Equipped with CEMS.
This provision directs operators of non-Part 75 units that use CEMS for reporting CO_2 emissions to follow the missing data substitution procedures in 40 CFR Part 75.

Rationale of Section 95129(b).
This provision is necessary for leveling the playing field among the units that use CEMS for reporting GHG emissions. U.S. EPA requires conservative and stringent data substitution only for 40 CFR Part 75 units, but not for other types of units that also use CEMS equipment. Requiring Part 60 CEMS units with CO_2 monitor to follow the 40 CFR Part 75 requirements for CO_2 monitor in operating CEMS units ensures equity in data substitution.

Summary of Section 95129(c), Missing Data Substitution Procedures for Fuel Characteristic Data.
This provision provides instruction for estimating fuel characteristic data, and at the same time, creates an incentive for operators to avoid missing fuel characteristic data.

The operator is required to obtain a valid backup or replacement sample that would still meet the sampling requirements in the applicable California and U.S. EPA rules. If no backup or replacement sample can be obtained but the data capture rate is high, at greater than 90%, the operator is allowed to use the more lenient approach in U.S. EPA's GHG reporting rule. Otherwise, the operator must apply a gradually more stringent missing data estimation procedure depending on the amount of data missed.

Rationale of Section 95129(c).
This provision is necessary to create incentives for operators to achieve high data capture rate and to provide a consistent, enforceable rule for substituting missing fuel characteristic data.

Summary of Section 95129(c)(1).
This provision provides instruction for missing data substitution if data capture rate is higher than 90%.

Rationale of Section 95129(c)(1).
This provision is necessary to create incentives for operators to achieve high data capture rate and to provide a consistent, enforceable rule for substituting missing fuel characteristic data. Fuel characteristic data (such as high heat value and carbon content) generally have a range of values that is not arbitrary by definition, and the variations in values tend to be reasonably bounded. Therefore, staff determined that if a facility is missing a small amount of data (<10%), substituting with the average of the "before" and "after" values consistent with the U.S. EPA rule provides a reasonable estimate.

Summary of Section 95129(c)(2).
This provision gives instruction for missing data substitution if data capture rate is between 80% and 90%. If triggered due to percent data capture rate falling between 80% and 90%, the operator is required to substitute the missing value with the highest value recorded in 3 years.

Rationale of Section 95129(c)(2).
This provision is necessary to create incentives for operators to achieve high data capture rate and to provide a consistent, enforceable rule for substituting missing fuel characteristic data. This provision produces higher emissions numbers for compliance obligation determination; therefore, it creates an incentive for operators to achieve a high data capture rate especially when a carbon price is in place.

Summary of Section 95129(c)(3).
This provision provides instruction for missing data substitution if data capture rate falls below 90%. If triggered due to percent data capture rate falling below 80%, the operator is required to substitute the missing value with the highest value in all records kept. To ensure that the substituted value is at least as conservative as the default heat contents of 40 CFR Part 98 and the default carbon contents of Part 75, the operators are required to use the "greater" of the default value or the highest value in facility records for substitution.

Rationale of Section 95129(c)(3).
This provision is necessary to create incentives for operators to achieve high data capture rate and to provide a consistent, enforceable rule for substituting missing fuel characteristic data. This provision produces noticeably higher emissions numbers for compliance obligation determination; therefore, it creates incentives for operators to achieve a high data capture rate especially when a carbon price is in place.

Summary of Section 95129(d), Missing Data Substitution Procedures for Fuel Consumption Data.
This provision provides instruction for estimating fuel consumption data, and at the same time, creates incentives for operators to avoid missing fuel consumption data. The provision includes missing data substitution procedures for load-based units, non-load-based units, and an alternative substitution method.

Rationale of Section 95129(d).
This provision is necessary to create incentives for operators to achieve high data capture rate and to provide a consistent, enforceable rule for substituting missing fuel consumption data. Unlike fuel characteristic data, which generally has a range of values by definition, fuel consumption can range anywhere from zero to the maximum potential capacity of the equipment. Therefore, staff believes that missing fuel consumption data must be filled with values that can either be correlated with other measured operational parameters or be based on the actual fuel use values under usual operating conditions.

Because compliance obligations are assessed at the facility level, unit-level fuel consumption data do not need to be accurate to +/- 5%. As long as the facility-level fuel consumption data are accurate to +/-5%, best available estimate (consistent with U.S. EPA's GHG reporting rule) for unit-level fuel consumption data is sufficient. However, if an operator cannot accurately determine facility-level fuel consumption, the operator must use the more stringent missing data procedures prescribed in the following subparagraphs. The stringent procedures produce noticeably higher emissions numbers for compliance obligation determination; therefore, it creates incentives for operators to achieve high data capture rate especially when a carbon price is in place.

Summary of Section 95129(d)(1), Continuous Fuel Flow Rate Data Using Load Ranges.
This provision provides instruction for substituting missing fuel consumption data if load ranges can be established for the unit. The missing data procedure for load-based units

(units producing electrical and/or thermal output that are equipped with a data handling system that can automatically match up output data with fuel use data) is consistent with the methods in 40 CFR Part 75. The operators must substitute missing fuel consumption data based on the unit's actual load range of electricity production or thermal energy production during the hours when the fuel consumption data are missing. This section provides instruction for data substitution when only one fuel is fired as well as when multiple fuels are fired.

Rationale of Section 95129(d)(1).
This provision is necessary to create incentives for operators of load-based units to achieve high data capture rate and to provide a consistent, enforceable rules for substituting missing fuel consumption data.

Staff based the load-based missing data procedure on 40 CFR Part 75 methods because 40 CFR Part 75 procedures for load-based units are capable of producing reasonably accurate estimates. Two major differences between the rule texts in this subparagraph and those in 40 CFR Part 75 are: (1) This subparagraph clarifies the criteria for using the load-based procedures. (2) If not enough historical data are available for a given load range, the use of increasingly higher load ranges are allowed by this subparagraph. In contrast, 40 CFR Part 75 allows only one higher load range before requiring substitution using the maximum potential fuel consumption rate. The proposed approach should yield more accurate substitute data that correlate with fuel consumption values in comparison to the 40 CFR Part 75 approach.

Summary of Section 95129(d)(2), Fuel Consumption Data Without Load Ranges.
This provision gives instruction for substituting missing fuel consumption data if load ranges cannot be established for the unit. If fuel consumption data cannot be accurately determined at the facility level, the operator must use a tiered, increasingly more stringent approach for substituting missing fuel use data. The operators are required to use a best available estimate consistent with the 40 CFR Part 98 if the data capture rate is greater than 95%, use the 90th percentile value of fuel use rates in the facility's records if the data capture rate is between 95% and 90%, use the 95th percentile value of fuel use rates in the facility's records if the data capture rate is below 90% but greater than 80%, and use the maximum potential fuel consumption rate if the data capture rate is below 80%. This section provides instruction for data substitution when only one fuel is fired as well as when multiple fuels are fired.

Rationale of Section 95129(d)(2).
This provision is necessary to create incentives for operators to achieve high data capture rate and to provide a consistent, enforceable rule for substituting missing fuel consumption data. The rule for data substitution produces higher emissions numbers for compliance obligation determination; therefore, it encourages operators to achieve a high data capture rate especially when a carbon price is in place.

In section 95103, the revised rule requires the facility operator to periodically monitor the proper functioning of fuel measurement device and record fuel use data at least

weekly. Such monitoring will provide the historical data for missing data substitution. If an individual missing data period is shorter than the fuel consumption data monitoring period, the operator must prorate the measured data to match the missing data period.

Summary of Section 95129(d)(3), Alternate Missing Data Procedure for Fuel Consumption Data.
This provision gives instruction for substituting missing data if a unit does not meet the criteria for using either the load-based or the non-load-based procedure. The operator must conservatively substitute missing data using the maximum potential fuel flow rate.

Rationale of Section 95129(d)(3).
This provision is necessary to create incentives for operators to achieve high data capture rate and to provide a consistent, enforceable rule for substituting missing fuel consumption data. Because fuel consumption can range anywhere from zero to the maximum potential capacity of the equipment, fuel consumption data substitution must be filled with values that can either be correlated with other measured operational parameters or be based on the actual fuel use values under usual operating conditions. In the absence of measured operation parameters or actual fuel use values, the maximum potential fuel consumption rate is the most appropriate alternative. However, given that the proposed rule provides the option for facilities to use a best available estimate if facility level fuel consumption can be accurately determined, staff expects that it will be rare for any facility to use the maximum potential fuel flow rate as the last resort.

Summary of Section 95129(e), Missing Data Substitution Procedures for Steam Production.
This provision gives instruction for substituting missing steam production data. Units that do not use steam production data for emission calculation may follow the more lenient approach in the U.S. EPA rule (best available estimate based on available process data). Units that use steam production data for emission calculation must use a tiered, increasingly more stringent approach for substituting missing steam production data.

Rationale of Section 95129(e).
This provision is necessary to create incentives for operators to achieve high data capture rate and to provide a consistent, enforceable rule for substituting missing steam production data. Because compliance obligation is based on facility emissions, it is necessary to incentivize high data capture rate to prevent gaming. With a carbon price in place, the operators will avoid missing data.

Summary of Section 95129(e)(1).
This provision provides instruction for missing data substitution if the data capture rate is higher than 90%. The operator is allowed to use best available estimate based on available process data that are routinely measured and recorded at the unit.

Rationale of Section 95129(e)(1).
This provision is necessary to create incentives for operators to achieve high data capture rate and to provide a consistent, enforceable rule for substituting missing steam production data. At a high data capture rate, the operator has discretion to use a best available method to estimate missing data, which is consistent with the U.S. EPA approach.

Summary of Section 95129(e)(2).
This provision provides instruction for missing data substitution if the data capture rate is between 80% and 90%. If triggered due to percent data capture rate falling between 80% and 90%, the operators must use the 90th percentile value of fuel use rates in the facility's records.

Rationale of Section 95129(e)(2).
This provision is necessary to create incentives for operators to achieve high data capture rate and to provide a consistent, enforceable rule for substituting missing steam production data. It produces higher emissions numbers for compliance obligation determination; therefore, creating an incentive for operator to achieve a high data capture rate especially when a carbon price is in place.

Summary of Section 95129(e)(3).
This provision provides instruction for missing data substitution if the data capture rate falls below 80%. If triggered, the operators must use the highest valid steam production value recorded in all records kept.

Rationale of Section 95129(e)(3).
This provision is necessary to create incentives for operators to achieve high data capture rate and to provide a consistent, enforceable rule for substituting missing fuel characteristic data. It produces noticeably higher emissions numbers for compliance obligation determination; therefore, creating incentives for operators to achieve a high data capture rate especially when a carbon price is in place.

Summary of Section 95129(f), Procedure for Establishing Load Ranges.
This provision gives instruction for establishing load ranges for a unit that produce electrical or thermal output.

Rationale of Section 95129(f).
This provision is necessary because it enables the implementation of missing data substitution for load based units according to section 95129(d)(1). The procedure is consistent with the 40 CFR Part 75 method.

Summary of Section 95129(g), Executive Officer Approved Load Ranges.
This provision gives operators the option to use other types of load ranges beside electrical or thermal output, and establishes the procedure through which the operator may petition the Executive Officer for approval.

Rationale of Section 95129(g).
This provision is necessary to provide operators some flexibility in estimating missing data with relatively high accuracy. Alternative load metrics are allowed by 40 CFR Part 75. Therefore, the option for alternative load metrics is consistent with the U.S. EPA approach.

Summary of Section 95129(h), Procedure for Approval of Interim Fuel Analytical Data Collection Procedure During Equipment Breakdowns.
This provision lists the criteria and requirements for operators to request ARB's approval of interim data collection procedures during unforeseeable equipment breakdowns.

Rationale of Section 95129(h).
This provision is necessary to give operators some flexibility in complying with the regulation requirements and achieving conformance under unforeseeable breakdowns of equipment. At the same time, it allows for the collection of more accurate data for emissions calculations than if the missing data procedures in sections 95102(b)-(e) are implemented.

In the interest of balancing the collection of accurate data and creating an incentive to achieve a high data capture rate using a conservative substitution approach, the proposed regulation includes provisions to allow operators to submit alternative monitoring plans for ARB's approval in the event of an unforeseeable breakdown of equipment that is expected to cause a missing data rate of more than 20%, which is the threshold for an automatic nonconformance.

Summary of Section 95129(i), Procedure for Approval of Interim Data Collection Procedure During Breakdown for Units Equipped with CEMS.
This provision lists the criteria and requirements for operators that report emissions using CEMS to temporarily use fuel-based methods in the event of an unforeseeable breakdown of CEMS equipment, subject to ARB's approval.

Rationale of Section 95129(i).
This provision is necessary to give operators some flexibility in complying with the regulation requirements and achieving conformance under unforeseeable breakdowns of equipment. At the same time, it allows for the collection of accurate data for emissions accounting than if the missing data procedures in sections 95102(b)-(e) are implemented.

In the interest of balancing the collection of accurate data and creating an incentive to achieve a high data capture rate using a conservative substitution approach, the proposed regulation provides guidelines for an alternative monitoring plan and also makes allowance for sources reporting using CEMS (Tier 4) to temporarily use fuel-based calculation methods (Tiers 2 or 3) if certain criteria are met. This option is only available in the event of an unforeseeable equipment breakdown that is expected to

cause missing data rate of more than 20%, which is the threshold for an automatic nonconformance.

Summary of Section 95129(j), Cumulative Missing Data Elements.
This provision defines the minimum amount of data that must be captured in order to avoid a nonconformance finding. A nonconformance may not prevent a positive verification finding, depending on the contribution of the source to the facility emissions total.

Rationale of Section 95129(j).
This provision is necessary to maintain a certain level of data quality in conformance determinations during verification. Missing data elements cumulatively causing more than 80% of emissions to not be directly calculated from measure parameters is an automatic nonconformance even if the operator has correctly followed all the missing data substitution procedures in the regulation.

Subarticle 4
Requirements for Verification of Greenhouse Gas Emissions Data Reports; Requirements Applicable to Emissions Data Verifiers

This subarticle includes additions and modifications to the existing verification requirements of the current ARB GHG reporting regulation. These additions and modifications are summarized below, and an explanation of their necessity is also included. Provisions which have been retained and are not modified are not described below.

Summary of Section 95130, Requirements for Verification of Emissions Data Reports.

This section continues to specify that all emissions data reports are subject to annual verification and full verification with a site visit under certain circumstances. It also includes revisions to the verification requirements of the existing ARB GHG reporting regulation.

Rationale for Section 95130.
This section is necessary to inform reporting entities that they must obtain verification of their emission data reports on an annual basis. Verification is necessary to ensure the reported emissions do not contain a material misstatement and are reported in conformance with the requirements of the regulation. The changes to the existing requirements are necessary to provide a more rigorous verification schedule and process to support a cap-and-trade program.

Summary of Section 95130(a)(1), Annual Verification.
This provision clarifies that emissions data reports are subject to an annual verification. Triennial verification was removed as an option for verifiers and criteria were added to ensure a full verification takes place for 2011 data, when there is a change in a

verification body, when ownership of the reporting entity changes, when a previous year's emissions data report received an adverse verification statement, or when reported GHGs or MWhs differ greater than 25 percent from the previous year.

Rationale for Section 95130(a)(1).
This provision is necessary because annual verification ensures the rigorous reporting mechanism needed to support the cap-and-trade program. The new criteria to prompt a full verification are necessary to ensure that there is a complete review at the facility site when large changes occur in emissions or a change in ownership from one year to the next.

Summary of Section 95130(a)(2).
This provision maintains the requirement for reporting entities to switch verification bodies and verifiers at least once every six years.

Rationale for Section 95130(a)(2).
This provision is necessary to ensure that reporting entities and verification bodies do not fall into comfortable and close business relationships which could lead to bias in the verification process.

Summary of Section 95131, Requirements for Verification Services.

This section clarifies and strengthens the existing requirements for verification services. It also provides methods for an Executive Officer to estimate emissions for reporting entities that receive an adverse verification statement (formerly, opinion) and a third option for a verification statement to let reporting entities with a non-conformance still use their reported data as a basis for a compliance obligation if the non-conformance does not lead to a material misstatement.

Rationale for Section 95131.
The changes and additions in this section are needed to provide consistency and clarity in the existing requirements and to support a cap-and-trade program.

Summary of Section 95131(a)(1), Notice of Verification Services.
This provision includes language to clarify that when conflict of interest and notice of verification services (COI/NOVS) forms are submitted together, the verifier must still wait 10 working days after the approval is issued, to begin verification services. ARB must be notified of any changes in the verification team at least 5 days before new staff participate in verification services.

Rationale for Section 95131(a)(1).
This provision is needed to add clarity to an existing requirement that allows verification bodies to streamline the conflict of interest and notice of verification services information to ARB. The clarification states that even with a combined submittal, ARB is still provided a 10 working day window to coordinate an audit with that verifier. A five-day period for ARB review of staff changes is needed to evaluate the potential conflict

between the operator and the new staff of the verification body or subcontractor.

Summary of Section 95131(a)(2).
This provision adds new sector specialists for new complex sources that require an in-depth understanding of industrial processes.

Rationale for Section 95131(a)(2).
This provision is needed because newly added industrial sectors require that verifiers need sector training in order to provide a thorough review of the emissions data reports.

Summary of Section 95131(a)(3).
This provision removes the requirement to provide duplicative information about the lead verifier.

Rationale of Section 95131(a)(3).
This provision was needed to remove duplicative information as part of the Notice of Verification Services submittal as this information has already been submitted as part of the Conflict of Interest form.

Summary of Section 95131(a)(4).
This provision requires that any change to information submitted to ARB under sections 95131(a)(1) and 95131(a)(3) be reported to ARB at least 5 working days prior to the start of verification services, and prior to the verification statement being submitted to ARB.

Rationale of Section 95131(a)(4).
This provision is needed to keep ARB updated with any change of submitted information during the verification process. ARB needs timely information about verifications to be able to plan and participate in verification audits.

Summary of Section 95131(b)(1)-(3), Verification Plan.
These provisions clarify requirements for verification plans, including the information required in the plan and that the verification body must discuss the scope of verification services with the reporting entity.

Rationale for Section 95131(b)(1)-(3).
These provisions are necessary to remove ambiguity and provide a clear standard for all verification plans.

Summary of Section 95131(b)(4).
This provision includes clarifications to existing requirements and a new requirement for sites visits to include a sector specialist, when applicable.

Rationale for Section 95131(b)(4).
This provision is necessary to remove ambiguity in existing requirements and ensure that a sector specialist who is most familiar with the types of sources for a reporting entity is part of the team that conducts a site visit.

Summary of Section 95131(b)(5)-(7).
These provisions include clarifications to existing requirements for activities conducted as part of assessing the completeness of the emissions data report and that reporting entities must provide any information required for verification to the verification team. Additional requirements are described that require verifiers to review specific information during the verification of an entity with electricity transactions.

Rationale for Section 95131(b)(5)-(7).
These provisions are necessary to remove ambiguity in existing requirements and provide clear direction on requirements for verifiers and reporting entities.

Rationale of Section 95131(b)(8), Sampling Plan.
This provision requires more information to be evaluated in the sampling plan for existing emissions data reports, including biofuels, and that it be updated as relevant information is identified during verification.

Summary of Section 95131(b)(8).
This provision is necessary to ensure that each verification body and verifier had a minimum standard of what was expected as part of developing a sampling plan for emissions data reports, including reports that include biofuels.

Summary of Section 95131(b)(9), Data Checks.
This provision adds new specific requirements when performing Data Checks, including tracing original data, reviewing data compliance and completion, recalculating where possible and reviewing meter instrumentation accuracy.

Rationale of Section 95131(b)(9).
This provision is necessary to ensure minimum quality in the data checks and provide consistency between all verifications so that key aspects of the emissions data report are evaluated.

Summary of Section 95131(b)(10) Emissions Data Report Modifications.
This provision requires reporting entities to correct errors in the emissions data report where possible.

Rationale of Section 95131(b)(10).
This provision is needed in order to get the most accurate data possible. Reporters will now be required to fix problems in their emissions data reports, whereas the current regulation does not require mistakes in the report to be fixed by the reporting entity.

Summary of Section 95131(b)(11), Findings.
This provision maintains the requirement for verification teams to recalculate emissions for sources selected for data checks and evaluate the emissions data report for conformance with the regulation.

Rationale of Section 95131(b)(11).
This provision is needed to clarify to verifiers what they need to do as part of determining their findings for an emissions data report.

Summary of Section 95131(b)(12), Log of Issues.
This section requires that the verifier add specific information to the log of issues.

Rationale of Section 95131(b)(12).
This provision is necessary to provide standard information in the issues log for reporting entities. The additional text provides a clear listing of what verifiers must include in the log of issues so that reporting entities know what was wrong in the emissions data report and how the issues were resolved, and supports ARB oversight and audits.

Summary of Section 95131(b)(13)-(14).
These provisions include a materiality misstatement assessment equation and describe how to apply it to the emissions data report.

Rationale for Section 95131(b)(13)-(14).
These provisions are necessary to provide a consistent method for all verifiers to assess the quality of the emissions data report. The equation is already being used in existing voluntary and regulatory programs. Material misstatement is only assessed for emissions that would have an obligation under the cap-and-trade program.

Summary of Section 95131(b)(15), Conformance.
This provision requires a verification team to review specific information in the emissions data report for conformance with the regulation, but does not require all of that information to be subject to a material misstatement assessment.

Rationale for Section 95131(b)(15).
This provision is needed to ensure that all information in the emissions data report chosen for data checks was subject to all of the verification services. However, only the emissions sources chosen as part of the data checks are subject to a material misstatement assessment.

Summary of Section 95131(b)(16), Review of Missing Data Substitution.
This provision adds requirements for how emissions calculated using the missing data provisions will be treated during the material misstatement assessment.

Rationale for Section 95131(b)(16).
This provision is needed to provide direction to the verification team on how to evaluate the accuracy of emissions calculated using the missing data substitution requirements of this regulation.

Summary of Section 95131(c)(1)-(3), Verification Statement.
These provisions change the term verification opinion to verification statement and provide more detail on the duties of the independent reviewer. The verification team is now required to have a final discussion with the reporting entity in order to explain the findings of the verification.

Rationale for Section 95131(c)(1)-(3).
These provisions are needed to make terminology consistent with other comparable programs, and to give more direction to the lead verifiers in a verification body that act in the capacity of an independent reviewer. The requirement for the verification team to discuss the findings with the reporting entity and the requirement to describe the cause of an adverse statement provides more information to the reporting entity regarding any mistakes identified in the emissions data report.

Summary of Section 95131(c)(4).
This provision shortens the deadlines for the Executive Officer to make a determination on the verifiability of the report, and for the reporting entity to have their emissions data report verified, if applicable.

Rationale for Section 95131(c)(4).
This provision is necessary to support the need for timely data in a cap-and-trade program.

Summary of Section 95131(c)(5), Assigned Emissions Level.
This new provision provides criteria for how the Executive Officer will calculate an assigned emissions level to form the basis of a surrender obligation when an emissions data report receives an adverse verification statement.

Rationale for Section 95131(c)(5).
This provision is necessary so that a reporting entity that does not provide accurate data in their emissions data report can be assigned a number that forms the basis of their obligation in the cap-and-trade program. The criteria will support the Executive Officer to assign a representative and conservative emissions number to the reporting entity.

Summary of Section 95131(d).
This provision states that the verification requirements are complete once a verification statement is submitted to ARB and changes are no longer allowed to be made to emissions data reports after the verification statement is submitted to ARB.

Summary for Section 95131(d).
This provision is necessary to provide accurate and stable data for use in the cap-and-trade program.

Summary of Section 95131(e).
This provision states that where a high conflict of interest is discovered between the reporting entity and the verification body, or where a facility with a positive or qualified positive verification statement fails an ARB audit, the Executive officer may set aside the statement and require the facility to be reverified within 90 days.

Rationale for Section 95131(e).
This provision is necessary to deter high conflict of interest relationships between verifiers and reporters, and provides clear requirements for re-verification.

Summary of Section 95131(f).
This provision requires the reporting entity to provide detailed information about the emissions data report to the Executive Officer within 10 working days of a request by ARB.

Rationale for Section 95131(f).
This provision is needed to ensure a timely response by reporters as part of ARB's program oversight.

Summary of Section 95131(g).
This provision requires verification bodies to provide specified information to the Executive Officer within 10 working days of a request by ARB.

Rationale for Section 95131(g).
This provision is needed to ensure ARB is able to provide program oversight and has the ability to audit verifications to ensure conformance with the requirements of the regulation by gaining access to relevant documents from the verification body within a timely manner.

Summary of Section 95131(h), ARB Audits.
This provision states that ARB must provide written notification to verification bodies in order to audit individual verifiers that provide verification services.

Rationale for Section 95131(h).
This provision is needed to ensure ARB is able to audit individual verifiers to ensure verifiers are providing high quality verification services.

Summary of Section 95131(i), Biomass-Derived Fuels.
This provision requires additional verification steps to verify reported emissions that include biomass-derived fuels that are not subject to an obligation in the cap-and-trade program. The requirements include site visits and document reviews for every party in

the chain of custody between the biomass-derived fuel producers to the reporting entity that is including those emissions in their emissions data report.

Rationale for Section 95131(i).
This provision is needed because there is no established system to track biomass-derived fuels once they are injected into a common transmission pipeline. In many cases, a reporter claiming biomass-derived emissions may not actually be combusting the fuel they bought from out of state. Because the emissions from these fuels are exempt from being subject to an obligation, there needs to be a way to ensure the purchases of such fuels did occur from an actual biomass-derived fuel producing facility and that there is no double crediting or selling of these fuels from the point of production to the point of combustion. These requirements are needed to uncover any false claims of emissions from biomass-derived fuels.

Summary of Section 95131(i)(1).
This provision requires conflict of interest to be assessed by the verification body against every entity that sold, produced, or combusted the biomass-derived fuel.

Rationale for Section 95131(i)(1).
This provision is needed to ensure that every entity in the chain of custody of the biomass-derived fuel has no existing financial or other relationship with the verification body that could lead to any type of bias during the verification process.

Summary of Section 95131(i)(2), Biofuel Chain-of-Custody Evaluation.
This provision requires a verifier to make a site visit to each entity in the chain of custody for the fuel during the years full verification in required. The site visit will be to the location of data management when the biomass-derived fuel entity is a marketer, distributor, or suppler who does not produce or store the fuel on site. Verifiers must review fuel contracts and make determinations on whether the contract was in place before January 1, 2010 or the fuel is part of increased production at the facility. The verifier must also determine whether the fuel is already part of offset credits, whether the facility is producing fuel in accordance with 95852.2, whether the reported chain of custody and data monitoring is accurate, and the accuracy of the reported fuel volumes and emissions.

Rationale for Section 95131(i)(2).
This provision is needed to prevent contract shuffling that results in no actual GHG emissions reductions, ensure that biomass-derived fuels are not receiving credit for GHG reductions under any other program, that only increased biomass-derived fuel production avoids compliance obligations unless an existing contract is in place before January 2010, and that the fuel is tracked and managed accurately so that the verifier can establish ownership through the entire supply chain.

Summary of Section 95131(i)(3).
This provision states that if any entity in the chain of custody for biomass-derived fuels does not provide required information to the verifier, the biofuel will be considered unverifiable and subject to a compliance obligation.

Rationale for Section 95131(i)(3).
This provision is needed so that the verifier can review documentation to establish the chain of custody for biomass-derived fuels and to assess the validity of the avoided compliance obligation. This provision specifies the consequences when that data is not made available to the verifier.

Summary of Section 95131(i)(4).
This provision states that verifiers must evaluate material misstatements by comparing errors, omissions and misreporting with the reported emissions. Verifiers review methods and factors to determine conformance with the regulation.

Rationale for Section 95131(i)(4).
This provision is needed to ensure that biomass-derived fuels are evaluated for materiality and conformance using the same methods as verifiers use for emissions from facilities.

Summary of Sections 95131(i)(5).
This provision states that biomass-derived fuels must be measured accurately to within 95%, that heat content must be calculated correctly using a specified method, and that 95% of the data must be collected and provided to the verifier upon request. If these specified criteria are not met, the fuel is considered unverifiable and the operator is subject to a compliance obligation for the unverified biofuel.

Rationale for Section 95131(i)(5).
This provision is needed so that fuel providers understand that in order for fuel to be verified as biomass-derived, the fuel must be measured accurately, the heat content must be calculated using the method in 95115(c), and that if any of the biofuel providers or suppliers in the chain of custody do not collect at least 95% of the data used to evaluate the fuel, all of the fuel is considered unverifiable, which includes fuel where data was collected correctly, and not just the portion of fuel where data was missing for that reporting year.

Summary of Section 95131(i)(6).
This provision states that any operator that has reported a fuel which cannot be successfully verified as a biomass-derived fuel without a compliance obligation, will have an obligation for that fuel.

Rationale for Section 95131(i)(6).
This provision is needed to ensure that any claim of emissions that are attributed to a biomass-derived fuel that are included in an emissions data report that receives an

adverse verification statement will be subject to a compliance obligation in the cap-and-trade program.

Summary of Section 95132(a), Accreditation Requirements for Verification Bodies, Lead Verifiers, and Verifiers of Emissions Data Reports and Offset Project Data Reports.

This section requires verification bodies, lead verifiers, and verifiers for both mandatory reporting and offset project verification to meet the accreditation requirements of this section.

Rationale for Section 95132(a).
These changes were necessary in order to establish consistent accreditation requirements for verification services for this article and the cap-and-trade regulation.

Summary of Section 95132(b)(1)-(3).
These provisions require an increase in liability insurance to four million dollars and a requirement to maintain that insurance for three years after completing verification services. Staff training now includes participating in ARB verifier training on an ongoing basis. Along with current requirements for sector specific verifiers, language was added to require offset project specific verifiers to seek sector accreditation. Existing verifiers will also have to take ARB approved training on the revisions to the regulation to continue to provide verification services. Language grandfathering verifiers from other programs into ARB's program has been removed.

Rationale for Section 95132(b)(1)-(3).
These provisions are necessary because the cap-and-trade program will monetize emissions, and so it is especially important for verification bodies to carry enough liability insurance for a sufficient period of time after verification in order to provide recourse to a client for any errors in their work. This new level of insurance is comparable to the level of insurance required for verification bodies in voluntary programs. The insurance has to be maintained long enough to cover one compliance period amount under the reporting program. Accredited verifiers must keep current with regulatory changes and updates, so continued training is needed to ensure a rigorous verification program.

Summary for Section 95132(b)(4).
This provision adds language requiring certain standards for all ARB-approved training. These standards include receiving a 70% passing score on the final examination, and one opportunity for a retake of the exam. The provision does not allow for exams to be retaken under previous versions of the regulation after training has been updated for the new version of the regulation.

Rationale for Section 95132(b)(4).
This provision is necessary to create consistency amongst verification training and verifiers.

Summary of Section 95132(b)(5)-(6), Sector Specific and Offset Project Specific Verifiers.
These provisions add minimum requirements for Sector Specific and Offset Project Specific Verifiers to require at least two years of professional experience in the sector in which they wish to obtain accreditation. Other requirements include being in good standing with CAR prior to November 1, 2010 and having performed at least two project verifications by December 31, 2010, or having two years of professional experience related to the offset type as well as taking ARB project specific verification training, and passing the course and the final course exam. These provisions also clarify that the Executive Officer may request additional information about the qualifications of the accredited verifier or verification body.

Rationale for Section 95132(b)(5)-(6).
These provisions are necessary to ensure sector and offset verifiers have the skills and knowledge to understand and verify sources in their sectors. These provisions are also needed because the Executive Officer must be able to obtain sufficient information about all accreditation applicants, including information not specified in the regulation, in order to evaluate their accreditation fairy and accurately.

Summary of Section 95132(c)(1)-(4), Re-Accreditation by ARB.
These provisions include new language related to re-accreditation for a verification body, verifier or lead verifier. Any verification body or verifier that is subject to ARB enforcement action will not be re-accredited. All training requirements must be fulfilled at the time of reapplication with requirements added to ensure that applicants who did not participate in one verification by January 1, 2012 must take part in ARB approved GHG verification training, receiving at least a 70% passing score on the exit examination. Similarly, applicants who have participated in a verification before January 1, 2012 must take ARB approved abbreviated GHG training that includes training on changes to the regulation. Verifiers seeking reaccreditation must also score at least 70% on the exit exam during training.

Rationale for Section 95132(c)(1)-(4).
These provisions are needed to ensure that re-accreditation is only allowed for qualified verifiers and ensures that all verifiers fully understand any new components of the program. The requirements are necessary to provide consistency amongst the verifiers and in the verification program.

Summary of Section 95132(c)(5)-(8).
These provisions require verification bodies to meet the requirements of the regulation in order to be re-accredited by the Executive Officer. Verifiers may be re-accredited for a longer time than 3 years if specified criteria are met. If corrective action is required under a different program, the verifier must notify ARB and provide information about that action. Additional training is required for verifiers that are accredited before January 2011.

Rationale for Section 95132(c)(5)-(8).
These provisions are needed to ensure verification bodies are in good standing with ARB and other GHG programs before re-accreditation is renewed. It is necessary for ARB to evaluate any corrective actions in other programs in order to ensure any verifier weaknesses are identified, and that verifiers take more training so that they have a complete understanding of changes to the regulation.

Summary of Section 95132(d), Revocation of Accreditation by ARB.
This provision allows the Executive Officer to review and revoke an accreditation for any violation of subarticle 4, or an analogous GHG system. Limits are placed on verification body and verifiers so that they may not continue to offer verification services during the suspension or revocation process. If a verification body or verifier has their accreditation suspended or revoked, they must notify their current clients or clients for whom they have provided services in the past 6 months, within 5 working days and the clients must contract for verification services with a different verification body.

Rationale for Section 95132(d).
This provision is necessary because it is important to the quality of the program to not allow verifiers or verification bodies to continue to be active when serious concerns over their work have been uncovered in other voluntary or mandatory programs. The new requirements allow the Executive Officer to act on any concerns regarding a verifier or verification body's conduct in any similar voluntary or mandatory program to maintain quality in the ARB program. Reporting entities, offset project operators, and authorized project designees will now be informed in a timely manner if they need to contract with a new verifier or verification body.

Summary of Section 95132(e).
This provision specifies how subcontractors may participate on a verification team, and requires a lead verifier that is not a subcontractor to be the independent reviewer for the verification body.

Rationale for Section 95132(e).
This provision is necessary to clarify that only employees of the verification body may review the work done on behalf of the verification body. This requirement ensures that only full-time employees of a verification body are assigned the responsibility of evaluating the regulatory and financial liabilities of providing verification services under ARB's GHG program, and of protecting the business interests of that verification body.

Summary of Section 95133, Conflict of Interest Requirements for Verification Bodies for Emissions Data Reports.

Summary of Section 95133(a).
This section includes changes to clarify and strengthen the conflict of interest requirements between verification bodies, verifiers, and reporting entities.

Rationale for Section 95133(a).
This section is necessary to ensure a truly unbiased review of emissions data reports. The integrity of the verification program relies heavily on the true independence of verifiers as they review an emissions data report for a reporting entity.

Summary of Section 95133(b), High-risk Conflict of Interest.
This provision requires additional activities to be included as a high-conflict activities. Also added were owning, buying, and trading shares in an offset project, dealing with credits on behalf of an offset project manager, or where any staff member of the verification body provides any type of incentive to an operator to secure a contract. Definitions for "member" and "related entity" for the purposes of this section have been added.

Rationale for Section 95133(b).
This provision is necessary to ensure that there is no bias in the independent review of the submitted GHG emissions data report, especially if those sources or systems are subject to review for other purposes. The new activities acknowledge the increased activity in offsets and their close relationship to GHG accounting and that these activities are within the realm of GHG services that could be provided to the same reporters subject to the market program. The limits on incentives to procure verification services ensure that the program maintains a high level of objectivity. The new definitions provide for a consistent interpretation of those terms by verification bodies as they assess their conflict of interest.

Summary of Section 95133(c), Low-risk Conflict of Interest.
This provision requires the verification body to evaluate any non-verification work performed for the operator within the past 3 years in order for the conflict of interest for a verification to be identified as a low conflict under certain criteria.

Rationale for Section 95133(c).
This provision is needed to ensure that previous non-verification work represents a small fraction of the work done for that reporting entity, and that the non-verification work does not bias the verification work performed by the verification team.

Summary of Section 95133(d), Medium-risk Conflict of Interest.
This provision specifies how a verification body determines if a conflict of interest is a medium risk. A medium risk includes any risk that is not low or high risk. A medium risk is also identified when any personal or family relationships exist between the operator and the staff of the verification body. The verification body is required to disclose the nature of the conflict in a mitigation plan, and the Executive Officer evaluates the conflict and determines if the verification may proceed.

Rationale for Section 95133(d).
This provision is necessary to ensure that existing relationships are disclosed to ARB so the Executive Officer may review and determine if the relationship may impact the impartiality of the verification body. A medium conflict requires the verification body to

submit a mitigation plan to ARB so that a written accounting of the conflict can be reviewed.

Summary of Section 95133(e).
This provision requires verification bodies to self-evaluate their risk of conflict of interest for verifications, identify the nature of any past work, and to attest that their assessment is true, accurate, and complete.

Rationale for Section 95133(e).
This provision is necessary to ensure that verification bodies carefully evaluate their potential conflict of interest, disclose any previous business relationships with reporting entities, and attest to the accuracy of the conflict of interest submittal.

Summary of Section 95133(f), Conflict of Interest Determinations.
This provision reduces the time allowed for providing a conflict of interest determination by the Executive Officer.

Rationale for Section 95133(f).
This provision is needed to ensure a timely response to support a shorter verification period, and to identify what actions the Executive Officer may take if an emerging conflict of interest is identified during or after verification has occurred, including revocation of accreditation.

Summary of Section 95133(g), Monitoring of Conflict of Interest Situations.
This provision requires the verification body to inform the Executive Office if they have an emerging conflict of interest. The provision also requires the verifier to submit a mitigation plan for review if the new situation is considered "medium" conflict. If the new situation is a high conflict, services may not proceed, and accreditation for the verification body may be revoked.

Rationale for Section 95133(g).
This provision is needed to clarify what "emerging conflict" means and implications for the concurrent verification services, and allows the verification body and reporting entity to assess the risk to the verification process and verification body or verifier accreditation as they consider any new contracts for additional work.

Subarticle 5
Reporting Requirements and Calculation Methods for Petroleum and Natural Gas Systems

Subarticle 5 sets forth reporting requirements in the following sections:

95150: Definition of the Source Category
95151: Reporting Threshold
95152: GHGs to Report
95153: Calculating GHG Emissions

95154: Monitoring and QA/QC Requirements
95155: Procedures for Estimating Missing Data
95156: Data Reporting Requirements
95157: Records that Must be Retained
95185: Data Tables

Rationale for Subarticle 5.
This provision is necessary because at the time the current ARB GHG reporting regulation was designed it was recognized that both combustion and process/vented emissions were important GHG emissions sources for this sector. Initially oil and gas producers only reported stationary combustion emissions. ARB staff has worked with WCI partners to develop methods for the reporting of additional process/vented emission sources. The Draft U.S. EPA Mandatory Reporting Rule did contain methods specific to this sector in Subpart W – Oil and Natural Gas Systems. This section was withdrawn before the U.S. EPA MRR became final on October 30, 2009. Subpart W was subsequently re-released by U.S. EPA and is currently in draft form. Since its re-release, ARB staff has been working with the WCI Reporting Committee's Oil and Gas Subcommittee' to harmonize the WCI Draft methods with this U.S. EPA draft. Subarticle 5 is the result of this harmonization process. Most of the U.S. EPA proposed methodologies were adopted with no or very minor changes. For several sources, WCI determined that major modifications were required. The changes set forth in this Subarticle were deemed necessary to ensure that all methods produced data that was cap-and-trade quality. In several instances, WCI concluded that there were not methodologies available which would produce cap-and-trade quality data and these methods are included in this Subarticle for reporting purposes only.

Summary of 95150, Definition of the Source Category.

This provision defines the Source Category for the Petroleum and Natural Gas Systems as follows:

1. offshore petroleum and natural gas production
2. onshore petroleum and natural gas production
3. onshore natural gas processing plants
4. onshore natural gas transmission compression
5. underground natural gas storage
6. liquefied natural gas (LNG) storage
7. LNG import and export equipment
8. natural gas distribution

Rationale for Section 95150.
This provision is necessary to define which sectors must report and the reporting footprint for each of the eight sectors which are required to report under this regulation.

Summary of Section 95151, Reporting threshold.

This section points operators to the appropriate section where the reporting threshold is defined. It also directs operators to report emissions from portable equipment which may be stationed at a wellhead during the producing lifetime of the well.

Rationale for Section 95151.
This section is necessary to define the reporting threshold for this sector and clarify reporting responsibilities for stationary combustion emissions for portable equipment – emissions that may take place as the result of contracted services.

Summary of Section 95151(a).
This provision directs reporters to section 95150 and 95101(e) where the facility definition and reporting threshold for this sector are defined. It also clarifies that a reporting entity with more than one permit to operate wells in a basin would be considered one facility for purposes of reporting.

Rationale for Section 95151(a).
This provision is necessary to define who is required to report.

Summary of Section 95151(b).
This provision requires that the operator must include combustion emissions from portable equipment in its emissions data report.

Rationale for Section 95151(b).
This provision is necessary to ensure that all significant emissions from all aspects of crude oil and natural gas production are reported.

Summary of Section 95152, GHGs to Report.

This provision defines which sources must be reported for each of the eight sectors which are required to report in Section 95150.

Rationale for Section 95152.
This provision is necessary to define the reporting footprint for each of the eight sectors which are required to report.

Summary of Section 95152(a).
This provision establishes reporting requirements for industry segments in paragraph (b) through (i) of this section. It also requires reporting of flare emissions (section k) and requires operators to use provisions in section 95123 to report mass of all captured and supplied CO_2.

Rationale for Section 95152(a).
This provision is necessary because each of the industry segments have different reporting requirements which must be individually specified.

Summary of Section 95152(b).
This provision establishes reporting requirements for offshore petroleum and natural gas production, including all stationary fugitive and stationary vented sources as defined in the Mineral Management Service Gulfwide Offshore Activity Data System study (2005 Gulfwide Emission Inventory Study MMS 2007-067).

Rationale for Section 95152(b).
This provision is necessary because each of the industry segments have different reporting requirements which must be individually specified, and to inform operators of offshore petroleum and natural gas production facilities what they must report.

Summary of Section 95152(c).
This provision establishes reporting requirements for onshore natural gas processing.

Rationale for Section 95152(c).
This provision is necessary because each of the industry segments have different reporting requirements which must be individually specified, and to inform operators of onshore natural gas processing facilities what they must report.

Summary of Section 95152(d).
This provision establishes reporting requirements for onshore petroleum and natural gas production.

Rationale for Section 95152(d).
This provision is necessary because each of the industry segments have different reporting requirements which must be individually specified, and to inform operators of offshore petroleum and natural gas production facilities what they must report.

Summary of Section 95152(e).
This provision establishes reporting requirements for onshore natural gas transmission compression.

Rationale for Section 95152(e).
This provision is necessary because each of the industry segments have different reporting requirements which must be individually specified, and to inform operators of onshore natural gas transmission compression facilities what they must report.

Summary of Section 95152(f).
This provision establishes reporting requirements for underground natural gas storage.

Rationale for Section 95152(f).
This provision is necessary because each of the industry segments have different reporting requirements which must be individually specified, and to inform operators of underground natural gas storage facilities what they must report.

Summary of Section 95152(g).
This provision establishes reporting requirements for LNG storage.

Rationale for Section 95152(g).
This provision is necessary because each of the industry segments have different reporting requirements which must be individually specified, and to inform operators of LNG storage facilities what they must report.

Summary of Section 95152(h).
This provision establishes reporting requirements for LNG import and export equipment.

Rationale for Section 95152(h).
This provision is necessary because each of the industry segments have different reporting requirements which must be individually specified, and to inform operators of LNG import and export equipment what they must report.

Summary of Section 95152(i).
This provision establishes reporting requirements for natural gas distribution.

Rationale for Section 95152(i).
This provision is necessary because each of the industry segments have different reporting requirements which must be individually specified, and to inform operators of natural gas distribution facilities what they must report.

Summary of Section 95152(j).
This provision requires operators to report all flaring emissions.

Rationale for Section 95152(j).
This provision is necessary because flaring emissions from the industry segments can represent a large emission source and as such must be reported.

Summary of Section 95152(k).
This provision directs reporters to section 95115 where methodologies for the calculation of stationary combustion emissions are set forth.

Rationale for Section 95152(k).
This provision is necessary because standard methods are required across all entities to ensure data consistency and accuracy.

Summary of Section 95152(l).
This provision directs reporters to section 95123 where rules for reporting supplied CO_2 are established.

Rationale for Section 95152(l).
This provision is necessary to ensure complete GHG reporting for the petroleum and natural gas industry, and clarifies that operators must report all quantities of CO_2 captured and transferred.

Summary of Section 95153, Calculating GHG Emissions.

This provision contains all the reporting methodologies as well as methods for calculating volumetric and mass GHG emissions. This section also requires operators to report stationary combustion emissions and report all CO_2 sold and transferred off-site using methods in Section 95123.

Rationale for Section 95153.
This provision is necessary to define the methods that operators must use.

Summary of Section 95153(a), Natural Gas Pneumatic High Bleed Devices and Pneumatic Pump Venting.
This provision defines reporting methods for all high bleed natural gas powered pneumatic devices and pneumatic pumps. This section provides a graduated reporting requirement where reporters are required to meter 50 percent of all high bleed and pneumatic pump device natural gas emissions in year one (2013) and meter 100 percent of these emissions in year 2 (2014). Use of common plumbing and metering is encouraged wherever possible. Operators may use OEM derived emissions data for all low bleed pneumatics and un-metered devices and pumps.

Rationale for Section 95153(a).
This provision is necessary because WCI and ARB have required changes to the draft U.S. EPA language for this source to ensure that cap-and-trade quality data are generated. A graduated approach over two years has been proposed to give operators time to install the required metering.

Summary of Section 95153(a)(1).
This provision provides operators with a time line for the metering of all high bleed pneumatic devices and pneumatic pumps.

Rationale for Section 95153(a)(1).
This provision is necessary because metering of natural gas for high bleed pneumatics and pneumatic pumps is required and operators must install meters in an established time frame to meet the reporting requirements.

Summary of Section 95153(a)(2).
This provision details the methodology for the calculation of CH_4 and CO_2 from unmetered high bleed pneumatic devices and pneumatic pumps.

Rationale for Section 95153(a)(2).
This provision is necessary because only a portion of high bleed pneumatic devices and pumps must be metered during the first reporting year and this section sets forth reporting requirements for unmetered devices and pumps.

Summary of Section 95153(a)(3).
This provision details the methodology for the calculation of CH_4 and CO_2 from metered high bleed pneumatic devices and pneumatic pumps.

Rationale for Section 95153(a)(3).
This provision is necessary because only a portion of high bleed pneumatic devices and pumps must be metered during the first reporting year and this section sets forth reporting requirements for metered devices and pumps.

Summary for Section 95153(a)(4).
This provision directs reporters to methods for converting natural gas volumes to GHG mass emissions.

Rationale for Section 95153(a)(4).
This provision is necessary because natural gas consumption data derived from meters must be converted and reported as GHG emissions.

Summary for Section 95153(b), Natural Gas Pneumatic Low Bleed Device Venting.
This provision has been adopted without change from the U.S. EPA draft MRR. Operators may use OEM supplied data for all low bleed devices. Metering is not required for this group of devices given their low emissions rates compared with the high and continuous bleed devices and pneumatic pumps.

Rationale for Section 95153(b).
This provision is necessary because low bleed devices are defined as controllers where the bleed rate is equal to or less than six standard cubic feet per minute. These devices contribute a small fraction of the total emissions from pneumatic devices, thus a more relaxed methodology is appropriate.

Summary of Section 95153(b)(1).
This provision directs reporters to methods for the conversion of natural gas volumes to GHG mass emissions.

Rationale for Section 95153(b)(1).
This provision is necessary because meter derived natural gas consumption volumes must be converted to report CO_2 and CH_4 mass emissions.

Summary for Section 95153(c), Acid Gas Removal (AGR) Vent Stacks.
This provision establishes reporting requirements for Acid Gas Removal Vent Stacks. Operators must measure the volume weighted CO_2 content of gas entering and exiting the AGR unit on a quarterly basis. Two methods are provided. For absorbent based

dehydrators operators must use the GRI-GLYCalc simulation software. Operators using desiccant based dehydrators must use a method where desiccant volume and pressure are sued to calculate emissions which occur when the vessel is vented for desiccant refilling.

Rationale for Section 95153(c).
This provision is necessary because the U.S. EPA draft rule requires the use of a mass balance approach when determining CO_2 emissions from AGR vent stacks. ARB is recommending inclusion of this method without modification because AGR units are recognized to be a significant source of CO_2 and thus should be reported as part of a comprehensive GHG strategy. The proposed method uses data which operators already determine for operational control and gas QA/QC purposes and thus should not require additional sampling efforts.

Summary for Section 95153(d), Dehydrator Vent Stacks.
This provision sets forth methods for the calculation of vented emissions from absorbent and desiccant natural gas dehydrators which represent a significant source of natural gas methane and carbon dioxide emissions.

Rationale for Section 95153(d).
This provision is necessary because methane and CO_2 emissions resulting from the dehydration of natural represent a significant GHG source. Calculation methodologies must be applicable for both liquid absorbent technology and dehydration systems which use a solid desiccant. ARB and WCI recommend adopting the proposed U.S. EPA draft methodologies with very minor modification to Equation W-6 in the U.S. EPA proposed Subpart W. This equation has been modified by removing the time between filling terms. Operators simply calculate emissions for each venting/filling cycle.

Summary of Section 95153(d)(1).
This provision establishes reporting requirements for input into the simulation software package GRI-GLYCalc Version 4.

Rationale for Section 95153(d)(1).
This provision is necessary because minimum data input requirements are needed to ensure data quality and consistency.

Summary of Section 95153(d)(2).
This provision directs reporters to emission calculation methodologies for dehydrator vent emissions which are routed to flares or used as fuel.

Rationale for Section 95153(d)(2).
This provision is necessary to ensure that all emissions from dehydrator vent stacks are reported.

Summary of Section 95153(d)(3).
This provision establishes reporting requirements for reporters at facilities where desiccant dehydrators are employed.

Rationale for Section 95153(d)(3).
This provision is necessary because an emissions methodology is required for facilities where desiccant dehydrators are used.

Summary for Section 95153(e), Well Venting for Liquids Unloadings.
This provision establishes reporting requirements for emissions that result when a gas well is vented to the atmosphere to remove accumulated water and restore gas flow. These emissions may be substantial as typically gas wells may be vented for hours as the well gas flow is used to expel the accumulated water in the well.

Rationale for Section 95153(e).
This provision is necessary to inform operators which calculation methodology they must use. U.S. EPA has provided two calculation methods. Method one allows operators to calculate well venting emissions for each unique well tubing diameter and producing horizon/formation combination in each gas producing field. This data is then used with the total venting time for all similar wells. Method two requires operators calculate emissions from each well venting episode. WCI and ARB have concluded that method two provides more rigorous and accurate data. Therefore, operators must use the more accurate Method 2.

Summary for Section 95153(f), Gas Well Venting During Unconventional Well Completions and Workovers.
This provision defines unconventional wells as those wells where hydraulic fracturing has been employed to enhance gas production volumes. The U.S. EPA proposed methodology requires that operators calculate CO_2 and CH_4 emissions by measuring the time and gas flow rate during the period when the well is open to atmospheric during the venting process. Currently there are no EOR operations in California which employ fracking technology - there are no unconventional wells in California at this time. This methodology is included in the proposed regulation with no changes from the U.S. EPA draft Subpart W.

Rationale for Section 95153(f).
This provision is necessary in order to provide reporters with a methodology to calculate emissions from unconventional well completions and workovers

Summary of Section 95153(f)(1).
This provision establishes a reporting method for natural gas well venting during unconventional well completions and blowdowns.

Rationale for Section 95153(f)(1).
This provision is necessary because a methodology must be provided to quantify these emissions.

Summary of Section 95153(f)(2).
This provision directs reporters to methods for converting natural gas emissions to standard temperature and pressure.

Rationale for Section 95153(f)(2).
This provision is necessary to provide a method for operators to calculate GHG volume and mass emissions.

Summary of Section 95153(f)(3).
This provision directs reporters to methods for converting natural gas volume emissions at standard temperature and pressure to mass emissions.

Rationale for Section 95153(f)(3).
This provision is necessary because natural gas volume emissions must be converted to mass emissions prior to calculating GHG mass and volume emissions.

Summary of Section 95153(f)(4).
This provision establishes calculation methodologies for measurement of gas flow rates during well completions and workovers.

Rationale for Section 95153(f)(4).
This provision is necessary because standard methods must be required to ensure data accuracy and consistency.

Summary for Section 95153(g), Gas Well Venting During Conventional Well Completions and Workovers.
This provision requires operators to determine CO_2 and CH_4 emissions for each well completion and well workover using the daily gas production rate and cumulative time of well venting. This method has been included with no modifications from the proposed U.S. EPA draft Subpart W method.

Rational for Section 95153(g).
This provision is necessary to provide methods for conventional wells which do not employ hydraulic fracturing to enhance gas production. When conventional wells are drilled and worked over, emissions of CO_2 and CH_4 can be significant as the well is vented to the atmosphere.

Summary for Section 95153(h), Blowdown Vent Stacks.
This provision requires operators to calculate emissions from equipment blowdowns where natural gas is vented to the atmosphere. Operators must calculate the total volume which is vented and record the number of each unique equipment blowdowns per reporting period. If these emissions are flared, operators must use the method in Section 95153(l) to calculate flaring emissions. This method is included with no changes from the proposed U.S. EPA Subpart W calculation scheme.

Rationale for Section 95153(h).
This provision is necessary because blowdowns of equipment such as natural gas compressors represents a significant source of methane and CO_2 emissions.

Summary of Section 95153(h)(1).
This provision requires operators to calculate the volume of compressors which are blowndown (the variable V).

Rationale for Section 95153(h)(1).
This provision is necessary because this provision ensures that all blowdown volumes are determined.

Summary of Section 95153(h)(2).
This provision requires operators to maintain blowdown logs for each equipment type.

Rationale for Section 95153(h)(2).
This provision is necessary because logging of blowdown events is required to calculate blowdown emissions.

Summary of Section 95153(h)(3).
This provision establishes the calculation method for equipment blowdowns.

Rationale for Section 95153(h)(3).
This provision is necessary to ensure data consistency and accuracy.

Summary of Section 95153(h)(4).
This provision provides a method for natural gas volume conversion to standard temperature and pressure prior to calculating GHG emissions.

Rationale for Section 95153(h)(4).
This provision is necessary to ensure data quality and consistency.

Summary of Section 95153(h)(5).
This provision directs reporters to the sections of the regulation which detail conversion of natural gas volumes to GHG volume and mass emissions.

Rationale for Section 95153(h)(5).
This provision is necessary to ensure data quality and consistency.

Summary of Section 95153(i), Onshore Production and Processing Storage Tanks.
This provision provides two methods for the calculation of methane and CO_2 emissions from crude and condensate storage tanks. Method one must be used for storage tanks where the oil production rate is 10 bbl/day or less. In this case operators must use the E&P Tank software simulation package to estimate emissions. For storage tanks where the oil production rate is greater than 10 bbl/day, operators must collect a pressurized

sample at a location between the last separator and the storage tank, and determine the GOR and the methane content of the evolved gas. Method two assumes that all the methane released during the determination of GOR will be vented to the atmosphere as the crude/condensate product stabilizes after production.

Rationale for Section 95153(j).
This provision is necessary to provide consistency with U.S. EPA's proposed Subpart W where possible. It is also necessary because WCI and ARB concluded that actual measurement of GOR will provide a more accurate estimate of emissions. Thus method two is required for all storage tanks where production is above10 bbl/day.

Summary of Section 95153(i)(1).
This provision establishes reporting methods for storage tanks where oil production rates are 10 barrels per day or less.

Rationale for Section 95153(i)(1).
This provision is necessary to provide operators with the methodology to calculate storage tank emissions from production storage tanks where production is equal to or less than 10 barrels per day.

Summary of Section 95153(i)(2).
This provision establishes reporting methods for storage tanks where oil production rates are greater than 10 barrels per day.

Rationale for Section 95153(i)(2).
This provision is necessary to provide operators with the methodology to calculate storage tank emissions from production storage tanks where production greater than 10 barrels per day.

Summary of Section 95153(j), Well Testing and Flaring.
This provision requires that operators determine well venting and flaring emissions by determining the GOR of the hydrocarbon production from the well, the flow rate of oil per day, and the number of days per reporting period that the well was tested. If these emissions are flared, operators must use the method in Section 95153(l) to calculate flaring emissions.

Rationale for Section 95153(j).
This provision is necessary because when wells are tested to determine production characteristics the well may be opened to atmospheric pressure. Thus, significant emissions of CH_4 and CO_2 can be significant during well testing. This method has been adopted from the draft U.S. EPA Subpart W without changes. The methodology for the calculation of flaring emissions has been modified to address errors identified in the draft U.S. EPA methodology (see Section 95153(l) below).

Summary of Section 95153(j)(1).
This provision provides operators with details on sampling which must be conducted at each well.

Rationale for Section 95153(j)(1).
This provision is necessary because operators must understand what sampling is required.

Summary of Section 95153(j)(2).
This provision establishes the calculation method for this emission source.

Rationale for Section 95153(j)(2).
This provision is necessary because a standard method for calculating emissions is required to ensure data consistency and accuracy.

Summary of Section 95153(j)(3).
This provision directs reporters to the appropriate section where methods for conversion of natural gas volumes to standard temperature and pressure are located.

Rationale for Section 95153(j)(3).
This provision is necessary because a standard conversion method is required to ensure data consistency and accuracy.

Summary of Section 95153(j)(4).
This provision directs reporters to the appropriate sections of this regulation where methods for conversion of natural gas volume data to GHG mass emissions are located.

Rationale for Section 95153(j)(4).
This provision is necessary because a standard conversion method is required to ensure data consistency and accuracy.

Summary of Section 95153(j)(5).
This provision directs reporters to the appropriate section where methods for calculating flaring emissions are detailed.

Rationale for Section 95153(j)(5).
This provision is necessary because a standard methodology for the calculation of flaring emissions is required to ensure data consistency and quality.

Summary for Section 95153(k), Associated Gas Venting and Flaring.
This provision requires that operators determine associated gas well venting and flaring emissions by determining the GOR of the hydrocarbon production from the well and the total volume of oil produced per day for the well being tested. If these emissions are flared, operators must use the method in Section 95153(l) to calculate flaring emissions.

Rationale for Section 95153(k).
This provision is necessary because in cases where small amounts of associated gas may be stranded (there is no access to a gas pipeline), this gas may be vented or flared, resulting in significant methane and CO_2 emissions. This method has been adopted from the draft U.S. EPA Subpart W without changes. The methodology for the calculation of flaring emissions has been modified to address errors identified in the draft U.S. EPA methodology (see Section 95153(l) below).

Summary of Section 95153(k)(1).
This provision details sampling which must be conducted at each well.

Rationale for Section 95153(k)(1).
This provision is necessary to ensure that operators understand what sampling is required.

Summary of Section 95153(k)(2).
This provision establishes the calculation method for this emission source.

Rationale for Section 95153(k)(2).
This provision is necessary because a standard method for calculating emissions is required to ensure data consistency and accuracy.

Summary of Section 95153(k)(3).
This provision directs reporters to the appropriate sections of the regulation where methods for conversion of natural gas volumes to standard temperature and pressure are located.

Rationale for Section 95153(k)(3).
This provision is necessary because a standard conversion method is required to ensure data consistency and accuracy.

Summary of Section 95153(k)(4).
This provision directs reporters to the appropriate sections of the regulation where methods for conversion of natural gas volume data to GHG mass emissions are located.

Rationale for Section 95153(k)(4).
This provision is necessary because a standard method for calculating emissions is required to ensure data consistency and accuracy.

Summary of Section 95153(k)(5).
This provision directs reporters to the appropriate section of the regulation where methods for calculating flaring emissions are detailed.

Rationale for Section 95153(k)(5).
This provision is necessary because a standard methodology for the calculation of flaring emissions is required to ensure data consistency and quality.

Summary of Section 95153(l), Flare Stacks.
This provision sets forth reporting requirements and methods for emissions related to flaring of produced gas. Methodologies are included for calculating un-combusted methane emissions, pass through CO_2 emissions, and combusted emissions. In cases where vented and process emissions are captured and directed to a flare, reporters must use the calculation methods in this section.

Rational for Section 95153(l).
This provision is necessary because flares may be used to combust emissions from many sources such as equipment blowdowns, well testing, stranded gas, and storage tank vapor recovery. The U.S. EPA methodologies have been adopted with modifications to correct errors identified during the WCI harmonization process.

Summary of Section 95153(l)(1).
This provision establishes flare flow measurement requirements for this section.

Rationale for Section 95153(l)(1).
This provision is necessary to enable operators to determine flow to each flare.

Summary of Section 95153(l)(2).
This provision establishes gas composition measurement requirements for this section.

Rationale for Section 95153(l)(2).
This provision is necessary to enable operators to determine gas composition for each stream sent to each flare.

Summary of Section 95153(l)(3).
This provision establishes criteria for determining flare destruction efficiency

Rationale for Section 95153(l)(3).
This provision is necessary because a standard methodology for the determination of flare destruction efficiency is required to ensure data consistency and quality.

Summary of Section 95153(l)(4).
This provision directs reporters to section 95115 to access methods for calculating stationary combustion emissions.

Rationale for Section 95153(l)(4).
This provision is necessary because a standard method for calculation of all stationary combustion promotes data consistency and quality.

Summary of Section 95153(l)(5).
This provision contains methods for calculation of flare stack methane emissions and CO_2 combustion emissions.

Rationale for Section 95153(l)(5).
This provision is necessary to inform operators of the specific emissions calculation methods required to calculate methane and CO_2 flare combustion emissions.

Summary of Section 95153(m), Centrifugal Compressor Wet Seal Degassing Vents.
This provision contains methodologies for the calculation of methane emissions which result when oil used to provide a seal in natural gas compressors is purged of dissolved gas. Operators must determine both the wet seal degassing venting rates per unit time and mole fraction of CO_2 and CH_4 in the degassing emissions semi-annually and record the operational time for each degassing unit. If degassing vent emissions are captured and sent to a flare operators must use the flare stack emissions methodology (95153(l)) to estimate these flaring emissions.

Rationale for Section 95153(m).
This provision is necessary because emissions resulting from degassing of oil used to lubricate centrifugal compressor wet seals are recognized to be major source of vented emissions for natural gas compression. These emissions from wet seal oil degassing units may be vented directly into the atmosphere or captured and sent to a flare and this methodology covers each of these contingencies. The draft U.S. EPA methodology did not include a sampling frequency for the measurement of wet seal degassing vent emission rates and GHG mole fraction. Thus ARB has added a requirement to measure these two variables semi-annually. Otherwise, this methodology is unchanged from the U.S. EPA draft Subpart W method.

Summary of Section 95153(m)(1).
This provision establishes measurement requirements for this section.

Rationale for section 95153(m)(1).
This provision is necessary because standard measurement methods ensure data consistency and quality.

Summary of Section 95153(m)(2).
This provision establishes calculation methods for this source.

Rationale for section 95153(m)(2).
This provision is necessary because standard calculation methods ensure data consistency and quality.

Summary of Section 95153(m)(3).
This provision directs reporters to the appropriate section of the regulation where methods for conversion of natural gas volumes to standard temperature and pressure are located.

Rationale for section 95153(m)(3).
This provision is necessary because a standard conversion method is required to ensure data consistency and accuracy.

Summary of Section 95153(m)(4).
This provision directs reporters to the appropriate sections of the regulation where methods for conversion of natural gas volume data to GHG mass emissions are located.

Rationale for section 95153(m)(4).
This provision is necessary because a standard conversion method is required to ensure data consistency and accuracy.

Summary of Section 95153(m)(5).
This provision directs reporters to the appropriate section of the regulation where methods for calculating flaring emissions are detailed.

Rationale for section 95153(m)(5).
This provision is necessary because a standard conversion method is required to ensure data consistency and accuracy.

Summary of Section 95153(n), Reciprocating Compressor Rod Packing Venting.
This provision presents methodologies for the calculation of vented emissions from leaks in reciprocating compressor rod packing material.

Rationale for Section 95153(n).
This provision is necessary because leaks from reciprocating compressor rod packing are a very important source of fugitive methane emissions in the natural gas processing, transmission, and storage sectors. Rod packing emissions vary with the mode of compressor operation, thus it is important that emissions estimates be made in both operating and standby-pressurized modes. The methodology in this proposed regulation has been adopted without change from the U.S. EPA Subpart W draft.

Summary of Section 95153(n)(1).
This provision establishes emission calculation methods for this emission source.

Rationale for section 95153(n)(1).
This provision is necessary because a standard calculation method is required to ensure data consistency and accuracy.

Summary of Section 95153(n)(2).
This provision details the required measurement method for venting directed to an open ended vent line.

Rationale for section 95153(n)(2).
This provision is necessary because emissions may be directed to an open ended line and thus a consistent method of measuring these emissions is needed.

Summary of Section 95153(n)(3).
This provision details the required measurement method for venting not directed to an open ended vent line.

Rationale for section 95153(n)(3).
This provision is necessary because emissions may be vented directly and thus a consistent method of measuring these emissions is needed.

Summary of Section 95153(n)(4).
This provision requires operators to conduct measurements for three operational modes: (1) operating, (2) standby, pressurized, and (3) not operating, depressurized.

Rationale for section 95153(n)(4).
This provision is necessary to ensure emissions measurements are made in all operational modes where emissions occur.

Summary of Section 95153(n)(5).
This provision directs reporters to the appropriate section of the regulation where methods for conversion of natural gas volumes to standard temperature and pressure are located.

Rationale for section 95153(n)(5).
This provision is necessary because a standard conversion method is required to ensure data consistency and accuracy.

Summary of Section 95153(n)(6).
This provision directs reporters to the appropriate sections of the regulation where methods for conversion of natural gas volume data to GHG mass emissions are located.

Rationale for section 95153(n)(6).
This provision is necessary because a standard conversion method is required to ensure data consistency and accuracy.

Summary of Section 95153(o), Leak Detection and Leaker Emission Factors (reporting only).
This provision details a screening/emission factor methodology for the semi-quantitative determination of fugitive emissions. Operators are required to screen components and apply a default emissions factor to all components which are identified as "leakers".

Rationale for Section 95153(o).
This provision is necessary because fugitive emissions are by their nature, difficult to quantify. Methodologies such as hi-volume samplers and calibrated bags do provide quantitative information on component leak rates. However, these methods are expensive and labor intensive. Additionally, once a leaking component has been identified and the emission rate measured, one must estimate the length of time over which the component has been leaking – a difficult task. While the proposed method provides only semi-quantitative data which is for classified as "reporting only emissions" (no compliance obligation), the proposed method does provides operators with actionable information concerning which components are leaking and the relative order of magnitude estimate of leak rates.

Summary of Section 95153(o)(1).
This provision requires that operators report GHG emissions at standard temperature and pressure.

Rationale for Section 95153(o)(1).
This provision is necessary to ensure all GHG emissions are reported consistently.

Summary of Section 95153(o)(2).
This provision directs operators to the appropriate emission factors for affected components at natural gas processing facilities.

Rationale for Section 95153(o)(2).
This provision is necessary to enable operators to use the correct emissions factors.

Summary of Section 95153(o)(3).
This provision directs operators to the appropriate emission factors for affected components at onshore natural gas transmission compression facilities.

Rationale for Section 95153(o)(3).
This provision is necessary to enable operators to use the correct emissions factors.

Summary of Section 95153(o)(4).
This provision directs operators to the appropriate emission factors for affected components at underground natural gas storage facilities.

Rationale for Section 95153(o)(4).
This provision is necessary to enable operators to use the correct emissions factors.

Summary of Section 95153(o)(5).
This provision directs operators to the appropriate emission factors for affected components at LNG storage facilities.

Rationale for Section 95153(o)(5).
This provision is necessary to enable operators to use the correct emissions factors.

Summary of Section 95153(o)(6).
This provision directs operators to the appropriate emission factors for affected components at LNG import and export facilities.

Rationale for Section 95153(o)(6).
This provision is necessary to enable operators to use the correct emissions factors.

Summary of Section 95153(o)(7).
This provision directs operators to the appropriate emission factors for affected components at natural gas distribution facilities.

Rationale for Section 95153(o)(7).
This provision is necessary to enable operators to use the correct emissions factors.

Summary of Section 95153(p), Population Count and Emission Factors (reporting only).
This provision requires that operators simply conduct a component count and apply a default emissions factor for each component type. These emissions are classified as "reporting only emissions" and thus do not carry a compliance obligation.

Rationale for Section 95153(p).
This provision is necessary because the method provides semi-quantitative information on leaking components. Given the small size of these emissions on a facility basis, the use of expensive and labor intensive quantitative emissions measurement techniques is not justified, especially given the inherent difficulty in determining leak duration.

Summary of Section 95153(p)(1).
This provision directs operators to the appropriate sections of the regulation where methods for conversion of natural gas volume data to GHG mass emissions are located.

Rationale for Section 95153(p)(1).
This provision is necessary because a standard calculation method is required to ensure data consistency and accuracy.

Summary of Section 95153(p)(2).
This provision directs operators to the appropriate emission factors for affected components at onshore petroleum and natural gas production facilities.

Rationale for Section 95153(p)(2).
This provision is necessary to enable operators to use the correct emissions factors.

Summary of Section 95153(p)(3).
This provision directs operators to the appropriate emission factors for affected components at onshore natural gas processing facilities.

Rationale for Section 95153(p)(3).
This provision is necessary to enable operators to use the correct emissions factors.

Summary of Section 95153(p)(4).
This provision directs operators to the appropriate emission factors for affected components at underground natural gas storage facilities

Rationale for Section 95153(p)(4).
This provision is necessary to enable operators to use the correct emissions factors.

Summary of Section 95153(p)(5).
This provision directs operators to the appropriate emission factors for affected components at LNG storage facilities.

Rationale for Section 95153(p)(5).
This provision is necessary to enable operators to use the correct emissions factors.

Summary of Section 95153(p)(6).
This provision directs operators to the appropriate emission factors for affected components at LNG import and export facilities.

Rationale for Section 95153(p)(6).
This provision is necessary to enable operators to use the correct emissions factors.

Summary of Section 95153(p)(7).
This provision directs operators to the appropriate emission factors for affected components at natural gas distribution facilities.

Rationale for Section 95153(p)(7).
This provision is necessary to enable operators to use the correct emissions factors.

Summary of Section 95153(q), Offshore Petroleum and Natural Gas Production Facilities in both State and Federal Waters (reporting only).
This provision requires that operators of offshore petroleum and natural gas production facilities use methods contained in the Mineral Management Service (MMS) Gulfwide Offshore Activity Data System (GOADS) reporting program (GOADS 2005). It also provides operators who have not formerly reported using GOADS with the specific requirements they must follow.

Rationale for Section 95153(q).
This provision is necessary to maintain consistency with the U.S. EPA draft Subpart W. California offshore facilities have not previously reported emissions to MMS because participation in the GOADS program was required only for petroleum and natural gas production platforms located in the Gulf of Mexico. This reporting requirement extends this requirement to California off-shore platforms and informs them what GOADS requirements must be met.

Summary of Section 905153(r), Volumetric Emissions.
This provision provides a standard method for the conversion of volumetric natural gas emissions to standard temperature and temperature conditions. Operators must determine the ambient temperature and pressure condition under which volumetric emissions were made.

Rational for Section 95153(r).
This provision is necessary to enable operators to consistently calculate natural gas emissions at ambient conditions. These ambient measurements must first be converted to a standard temperature and pressure before volumetric and mass GHG emissions can be calculated.

Summary of Section 95153(r)(1).
This provision establishes a calculation method for conversion of natural gas volumetric emissions at ambient conditions to a standard temperature and pressure.

Rationale for Section 951539(r)(1).
This provision is necessary because standardized conversion equations are provided to help ensure data consistency and as a reporting aid.

Summary of Section 95153(r)(2).
This provision establishes a calculation method for conversion of GHG emissions at ambient conditions to GHG volumetric emissions at standard conditions.

Rationale for Section 951539(r)(2).
This provision is necessary because standardized conversion equations are provided to help ensure data consistency and as a reporting aid.

Summary of Section 95153(s), GHG Volumetric Emissions.
This provision provides a standard method for converting natural gas volumetric emissions to GHG volumetric emissions. Operators must determine the mole percent of each GHG in the natural gas.

Rationale for Section 95153(s).
This provision is necessary because a standard method for converting natural gas volumetric emissions to GHG volumetric emissions to ensure data consistency. Volumetric GHG emission must then be converted to mass GHG emissions as prescribed in the following section. Inclusion of this method will promote data consistency as they provide a standard method for this conversion.

Summary of Section 95153(s)(1).
This provision establishes a standard method for calculating CH_4 and CO_2 emissions from natural gas

Rationale for Section 95153(s)(1).
This provision is necessary because standardized conversion equations are provided to help ensure data consistency and as a reporting aid.

Summary of Section 95153(s)(2).
This provision directs operators to measure GHG mole percent of natural gas for each of the effected sectors.

Rationale for Section 95153(s)(2).
This provision is necessary to enable operators to measure the GHG percent of natural gas as defined in this section.

Summary of Section 95153(t), GHG Mass Emissions.
This provision provides a standard method for the conversion of GHG volumetric emissions to GHG mass emissions. Operators are not required to determine any additional information.

Rational for Section 95153(t).
This provision is necessary because this standard method for conversion of GHG volumetric emissions to GHG mass emissions provides data consistency and reduces the potential for calculation error.

Summary of Section 95153(u), EOR Injection Pump Blowdown.
Enhanced Oil Recovery CO_2 pumps must be blown-down periodically. This provision provides operators with a method to calculate CO_2 emissions which occur when an EOR CO_2 injection pump is blown-down.

Rationale for Section 95153(u).
This provision is necessary because while EOR activities in California are currently limited to water flood and thermal (steam) technologies, CO_2 based EOR may be employed in the State in the future. This method has been included without modification from the U.S. EPA draft Subpart W.

Summary of Section 95153(u)(1).
This provision directs operators to calculate the total blowdown volume for EOR injection pump blowdowns.

Rationale for Section 95153(u)(1).
This provision is necessary to enable operators to consistently calculate the variable "total volume of equipment blowdown chambers."

Summary of Section 95153(u)(2).
This provision requires reporters maintain a logs of the number of blowdowns in the reporting year.

Rationale for Section 95153(u)(2).
This provision is necessary because it enables operators to establish the total number of blowdowns, the variable N, which is required for emissions calculation.

Summary of Section 95153(u)(3).
This provision establishes the calculation methodology for this emission source.

Rationale for Section 95153(u)(3).
This provision is necessary to enable operators to consistently calculate emissions from EOR injection pump blowdowns.

Summary of Section 95153(v), Produced Water Dissolved CO_2.
This provision provides a method for the calculation of emissions from CO_2 retained in produced water. Operators are required to determine the amount of CO_2 dissolved in produced water quarterly.

Rationale for Section 95153(v).
This method has been included without modification from the U.S. EPA draft Subpart W. This provision is necessary because emissions of CO_2 from produced water represents on one of three reservoirs from which this entrained CO_2 may be emitted – produced hydrocarbons, produced water, or produced natural gas.

Summary of Section 95153(v)(1).
This provision establishes the sampling frequency and location for this source.

Rationale for Section 95153(v)(1).
This provision is necessary because standard sampling intervals and locations ensure data quality and consistency.

Summary of Section 95153(v)(2).
This provision details the calculation methodology for this emissions source.

Rationale for Section 95153(v)(2).
This provision is necessary to enable operators to calculate emissions for this source.

Summary of Section 95153(v)(3).
This provision states that operations that re-inject produced water directly into the hydrocarbon reservoir are not required to report emissions under this section.

Rationale for Section 95153(v)(3).
This provision is necessary to inform operators which operations are not required to report. Direct re-injection of produced water will not result in emissions.

Summary of Section 95153(w), Portable Equipment Combustion Emissions.
This provision requires that operators report all emissions from portable equipment that is deployed at a facility using methods described in section 95115 of this article.

Rationale for Section 95153(w).
This provision is necessary to ensure that all emissions associated with the exploration, well drilling, and production phases are reported. This requirement promotes data consistency across reporting entities where varying fractions of emissions are generated by operations conducted by contracted personnel.

Summary of Section 95154, Monitoring and QA/QC Requirements.

Summary of Section 95154(a).
This provision harmonizes monitoring, data and records requirements with the provisions for reporting of GHG emissions from this sector. This section requires that operators meet applicable requirements for monitoring, missing data procedures, data reporting and records retention.

Rationale for Section 95154(a).
This provision is necessary because this information is required input in the verification process for reported facility emissions. An accurate verification is a cornerstone of an effect GHG reporting and mitigation program.

Summary of Section 95154(a)(1).
This provision directs operators to sampling criteria for the optical gas instrument which is used to conduct leak detection.

Rationale for Section 95154(a)(1).
This provision is necessary because the use of a standard instrument operating protocol promotes data accuracy and data quality.

Summary of Section 95154(a)(2).
This provision directs operators to follow standard methods for meter, analyzer and pressure gauge calibration during the first and subsequent years.

Rationale for Section 95154(a)(2).
This provision is necessary because standard methods and intervals for instrument calibration promote data accuracy and consistency.

Summary of Section 95154(a)(3).
This provision sets forth requirements for the use of calibrated bags.

Rationale for Section 95154(a)(3).
This provision is necessary because standard methods for conducting leak measurements promote data accuracy and consistency.

Summary of Section 95154(b).
This provision establishes standard procedures for the use of a high volume sampler which must be used to measure leak emissions.

Rationale for Section 95154(b).
This provision is necessary because standard methods for conducting leak measurements promote data accuracy and consistency.

Summary of Section 95154(b)(1).
This provision provides operating instructions for the use of a high volume sampler.

Rationale for Section 95154(b)(1).
This provision is necessary because standard methods for conducting leak measurements promote data accuracy and consistency.

Summary of Section 95154(b)(2).
This provision establishes high volume sampler operating procedures in cases where the sampler is not capable of capturing all the emissions.

Rationale for Section 95154(b)(2).
This provision is necessary because standard methods for conducting leak measurements promote data accuracy and consistency.

Summary of Section 95154(b)(3).
This provision directs operators to the appropriate method for calculating GHG volumetric and mass emissions from volumetric natural gas emissions.

Rationale for Section 95154(b)(3).
This provision is necessary because conversion of natural gas volumetric emissions to GHG volumetric and mass emissions is required in this section. Standard conversion methods promote data accuracy and consistency.

Summary of Section 95154(b)(4).
This provision establishes calibration requirements for the high volume sampler.

Rationale for Section 95154(b)(4).
This provision is necessary because standard methods for instrument calibration promote data accuracy and consistency.

Summary of Section 95155, Procedures for Estimating Missing Data.

Summary of Section 95155(a).
This provision establishes missing data substitution procedures for operators in the petroleum and natural gas system sector.

Rationale for Section 95155(a).
This provision is necessary because these missing data substitution procedures are designed to provide a strong incentive for reporters to generate as complete a data set

as possible, while specifying how to generate substitution data in circumstances where data was unavoidably lost.

Summary of Section 95156, Data Reporting Requirements.

This provision modifies data reporting requirements to match the modified sampling and reporting frequencies. It also provides operators with a reporting method that avoids double-counting emissions that have been included elsewhere in the facility report.

Rationale for Section 95156.
This provision is necessary because an accurate GHG accounting procedure must avoid double-counting of emissions.

Summary of Section 95156(a).
This provision establishes data reporting requirements for each industry segment required to report by this MRR.

Rationale for Section 95156(a).
This provision is necessary because operators must report all required emissions as well as supporting data. Standard reporting procedures for all sources promotes data quality and consistency.

Summary of Section 95156(b).
This provision requires operators to report emissions separately for standby equipment.

Rationale for Section 95156(b).
This provision is necessary because operators must report all required emissions as well as supporting data. Standard reporting procedures for all sources promotes data quality and consistency.

Summary of Section 95156(c).
This provision establishes data reporting requirements for additional aggregated source types.

Rationale for Section 95156(c).
This provision is necessary because operators must report all required emissions as well as supporting data. Standard reporting procedures for all sources promotes data quality and consistency.

Summary of Section 95156(d).
This provision requires operators to report minimum, maximum, and average throughput for each operation listed in paragraphs (a)(1) through (a)(8) of this section.

Rationale for Section 95156(d).
This provision is necessary because operators must report all required emissions as well as supporting data. Standard reporting procedures for all sources promotes data quality and consistency.

Summary of Section 95156(e).
This provision requires operators to report the number of connected wells and whether the wells are producing oil, gas, or both.

Rationale for Section 95156(e).
This provision is necessary because operators must report all required emissions as well as supporting data. Standard reporting procedures for all sources promotes data quality and consistency.

Summary of Section 95156(f).
This provision requires operators to report emissions separately for portable equipment for drilling rigs, dehydrators, compressors, electrical generators, steam boilers, and heaters.

Rationale for Section 95156(f).
This provision is necessary because operators must report all required emissions as well as supporting data. Standard reporting procedures for all sources promotes data quality and consistency.

Summary of Section 95157, Records that Must be Retained.

This provision requires operators to retain records on the date of measurements, the results of emissions detection and measurement, of calibration reports, and on the inputs and outputs of calculations or emission computer model pursuant to section 95105 of this article.

Rational for Section 95157.
This provision is necessary because data retention requirements must match data reporting requirements to ensure that comprehensive report verification may be conducted. Moreover, this information is needed for data verification purposes.

Summary of Section 95158, Data Tables.

This provision contains seven data tables containing default emissions factors.

Rationale for Section 95158.
This provision is necessary in order to provide operators with the default emissions factors they are required to use to comply with the regulation.

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ATTACHMENT A

Proposed Regulation Order

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

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

Amend Division 3, Chapter 1, Subchapter 10, Article 2, sections 95100, 95101, 95102, 95103, 95104, 95105, 95106, 95107, 95108, 95109, 95110, 95111, 95112, 95113, 95114, 95115, 95130, 95131, 95132, and 95133, title 17, California Code of Regulations; repeal section 95125, title 17, California Code of Regulations; and add new sections 95100.5, 95116, 95117, 95118, 95119, 95120, 95121, 95122, 95123, 95129, 95150, 95151, 95152, 95153, 95154, 95155, 95156, 95157, and 95158, title 17, California Code of Regulations to read as follows:

Article 2: Mandatory Greenhouse Gas Emissions Reporting

Subarticle 1. General Requirements for Greenhouse Gas Reporting

§ 95100. Table of Contents

Subarticle 1. General Requirements for Greenhouse Gas Reporting

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§ 95100.5. Purpose and Scope

(a) The purpose of this article is to establish mandatory greenhouse gas (GHG) reporting, verification, and other requirements for operators of certain facilities that directly emit GHGs, suppliers of certain fuels and carbon dioxide, electric power entities, verifiers of GHG emissions data reports and offset project data reports submitted pursuant to the Cap-and-Trade Regulation, and verification bodies. This article is designed to meet the requirements of section 38530 of the Health and Safety Code, and to support GHG regulatory programs of the California Air Resources Board.

(b) *Organization of this Article.* Subarticle 1 specifies general requirements for the reporting of GHG emissions that apply to all reporting entities listed in section 95101. Subarticle 2 specifies reporting requirements and calculation methods for specific types of facilities and entities. Subarticle 3 specifies additional requirements for reported data, including procedures for the substitution for missing data. Subarticle 4 specifies verification requirements for GHG emissions data reports, requirements for those who provide verification services for GHG reporting entities, and accreditation requirements for verifiers of emissions data reports and offset project data reports. Subarticle 5 specifies reporting requirements and calculation methods for petroleum and natural gas production, processing, and storage facilities.

(c) *U.S. EPA GHG Reporting Rule.* This article incorporates various provisions of title 40, Code of Federal Regulations (CFR), Part 98. These provisions are a portion of the U.S. Environmental Protection Agency (U.S. EPA) Final Rule on Mandatory Reporting of Greenhouse Gases. Unless otherwise specified, references in this article to 40 CFR Part 98 are to those requirements promulgated by U.S. EPA on October 30, 2009, July 12, 2010, September 22, 2010, and October 7, 2010.

(d) Except as otherwise specifically provided:

(1) Wherever the term "Administrator" is used in the federal rules referred to in this article, the term "Executive Officer of the California Air Resources Board" or "Executive Officer" shall be substituted.
(2) Wherever the term "EPA" is used in the federal rules referred to in this article, the term "California Air Resources Board" or "ARB" shall be substituted.
(3) In cases where the owner and operator of a facility or a supplier are not the same party, the operator is responsible for compliance with this article.

NOTE: Authority cited: Sections 39600, 39601, 39607, 39607.4, 41511, 38510, and 38530, Health and Safety Code. Reference: Sections 39600, 41511, and 38530, Health and Safety Code.

§ 95101. Applicability.

(a) *General Applicability.*

(1) This article applies to the following entities:

(A) Operators of facilities located in California and included in 40 CFR §98.2(a)(1)-(3);

(B) Suppliers of fuels or carbon dioxide provided for consumption within California that are included in 40 CFR §98.2(a)(4) or specified below in subsection (c);

(C) Electric power entities as specified below in subsection (d); and,

(D) Operators of petroleum or natural gas systems as specified below in subsection (e).

(2) Any reporting entity that fits into one or more of the categories in subsection (a)(1) above for calendar year 2011 or later must submit an emissions data report for that year and for subsequent calendar years, except as provided in the report cessation provisions of subsection (h) of this section. The emissions data report must cover all source categories and GHGs for which calculation methods are provided or referenced in this article for the reporting entity. Except as otherwise specified in this article, the report must be compiled using the methods specified by source category in 40 CFR Part 98.

(3) *Verifiers and Verification Bodies.* In addition to the reporting entities specified in subsection (a)(1) above, this article contains requirements for entities acting as verification bodies and individuals acting as third party verifiers of emissions data reports and offset project data reports. These requirements are specified in sections 95130 through 95133 of this article.

(b) *Calculating GHG Emissions Relative to Reporting Thresholds.* For industrial sectors for which an emissions-based applicability threshold is specified in 40 CFR §98.2, the reporting entity must apply a threshold of 10,000 metric tons of CO_2e for reporting under this article. Operators of facilities and suppliers must calculate their emissions using the requirements of 40 CFR §98.2(b)-(g), using a 10,000 metric tons of CO_2e threshold to determine if reporting is required. For purposes of determining reporting applicability for a 10,000 metric tons of CO_2e threshold, combustion and process emissions of CO_2, CH_4 and N_2O must be included, but fluorinated gases may be excluded.

(1) Facilities with stationary combustion emissions are included according to the requirements of 40 CFR 98.2(a)(3), except that the thresholds for reporting in California are 10,000 metric tons of CO_2e and an aggregate maximum heat input capacity of 12 mmBtu/hr or greater.

(2) Notwithstanding 40 CFR §98.2(b)(2), operators of facilities and suppliers must include emissions of CO_2 from the combustion of biomass and other biofuels when determining applicability relative to thresholds for emissions reporting and cessation of reporting.
(3) Operators of geothermal generating units must report when total facility emissions of CO_2 and CH_4 equal or exceed 10,000 metric tons of CO_2e.

(c) *Fuel and CO_2 Suppliers.* The suppliers listed below, as defined in section 95102(a), are required to report under this article when they import and/or deliver an annual quantity of products that, when completely combusted or oxidized, 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:

(1) Position holders at terminals and refineries delivering petroleum products and/or biomass-derived fuels, as described in section 95121;
(2) Enterers that import petroleum products and/or biomass-derived fuels outside the bulk transfer/terminal system, as described in section 95121;
(3) Producers of biomass-derived fuels, as described in section 95121;
(4) All refiners that produce liquefied petroleum gas, without regard to product quantities, as described in section 95121;
(5) Operators of interstate pipelines delivering natural gas, as described in section 95122;
(6) California consignees of liquefied petroleum gas, as described in section 95122;
(7) Local distribution companies who are public utility gas corporations or publicly-owned natural gas utilities delivering natural gas, as described in section 95122;
(8) Operators of intrastate pipelines delivering natural gas as described in section 95122;
(9) All natural gas liquid fractionators, without regard to product quantities produced, as described in section 95122;
(10) All producers of carbon dioxide without regard to product quantity produced, and importers of carbon dioxide with annual bulk imports into California of 10,000 metric tons or more, as described in section 95123.

(d) *Electric Power Entities.* The entities listed below are required to report under this article:

(1) Electricity importers and exporters, as defined in section 95102(a);
(2) Retail providers, including multi-jurisdictional retail providers, as defined in section 95102(a);
(3) California Department of Water Resources (DWR);
(4) Western Area Power Administration (WAPA);
(5) Bonneville Power Administration (BPA).

(e) *Petroleum and Natural Gas Systems.* The facilities listed below, as specified in section 95150, are required to report under this article when their stationary combustion and process emissions equal or exceed 10,000 metric tons of CO_2e:

(1) Offshore petroleum and natural gas production facilities;
(2) Onshore petroleum and natural gas production facilities, when the reporting entity meets the requirements of section 95151(a)(1);
(3) Onshore natural gas processing plants;
(4) Onshore natural gas transmission compression facilities;
(5) Underground natural gas storage facilities;
(6) Liquefied natural gas storage facilities;
(7) Liquefied natural gas import and export facilities;
(8) Natural gas distribution facilities.

(f) *Exclusions.* This article does not apply to, and greenhouse gas emissions reporting is not required for:

(1) Electricity generating facilities that are solely powered by nuclear, hydroelectric, wind, or solar energy, unless on-site stationary combustion and process emissions equal or exceed 10,000 metric tons of CO_2e;
(2) Generating units designated as backup or emergency generators in a permit issued by an air pollution control district or air quality management district;
(3) Fire suppression systems and equipment;
(4) Portable equipment, except where specifically required to report under 40 CFR Part 98 or this article;
(5) Primary and secondary schools with a NAICS code of 611110.

(g) *Demonstration of Nonapplicability.* The Executive Officer may request a demonstration from any operator, supplier, or entity that the operator, supplier, or entity does not meet one or more of the applicability criteria specified in this article. Such demonstration must be provided to the Executive Officer within 20 days of receipt of a written request.

(h) *Cessation of Reporting.* Except as otherwise specified below, a facility operator or supplier whose emissions fall below the applicable emissions reporting thresholds of this article and who wishes to cease annual reporting must comply with 40 CFR §98.2(i). The operator or supplier must provide the letter notifications specified in 40 CFR §98.2(i) to the address indicated in section 95103 of this article. For purposes of this article:

(1) Wherever 40 CFR §98.2(i)(1) states "25,000 metric tons of CO_2e per year," the phrase "10,000 metric tons of CO_2e per year" shall be substituted.
(2) Wherever 40 CFR §98.2(i)(2) states "15,000 metric tons of CO_2e per year," the phrase "5,000 metric tons of CO_2e per year" shall be substituted.
(3) In cases of permanent shutdown as specified in 40 CFR §98.2(i)(3), a reporter must submit an emissions data report for the year in which a facility or

supplier's GHG-emitting processes and operations ceased to operate, and for the first full year of non-operation that follows.

(4) The verification requirements of this article do not apply to the first full year of non-operation following a permanent shutdown, but continue to apply to prior emissions data reports.

NOTE: Authority cited: Sections 39600, 39601, 39607, 39607.4, 41511, 38510, and 38530, Health and Safety Code. Reference: Sections 39600, 41511, and 38530, Health and Safety Code.

Subarticle 1: General Requirements for Greenhouse Gas Reporting

§ 95102. Definitions.

(a) For the purposes of this article, the following definitions shall apply:

(1) "Absorbent circulation pump" means a pump commonly powered by natural gas pressure that circulates the absorbent liquid between the absorbent regenerator and natural gas contactor.

(2) "Acid gas" means hydrogen sulfide (H_2S) and carbon dioxide (CO_2) contaminants that are separated from sour natural gas by an acid gas removal.

(3) "Acid gas removal unit (AGR)" means a process unit that separates hydrogen sulfide and/or carbon dioxide from sour natural gas using liquid or solid absorbents or membrane separators.

(4) "Acid gas removal vent stack emissions" mean the acid gas separated from the acid gas absorbing medium (e.g., an amine solution) and released with methane and other light hydrocarbons to the atmosphere or a flare.

(5) "Additional" means, in the context of offset credits, greenhouse gas emission reduction or GHG removal enhancement activities, that result in greenhouse gas reduction or GHG removal enhancements, other than those activities required by law or regulation, any legally binding mandate, or any greenhouse gas reduction or GHG removal enhancement activities that would otherwise occur in a conservative business-as-usual scenario.

(6) "Adverse verification statement" means a verification statement rendered by a verification body attesting that the verification body cannot say with reasonable assurance that the submitted emissions data report is free of material misstatement.

(7) "Air injected flare" means a flare in which air is blown into the base of a flare stack to induce complete combustion of low Btu natural gas (i.e., high non-combustible component content.)

(8) "Allowance" means, unless the plain meaning of the word indicates otherwise, a limited tradable authorization to emit up to one metric ton of carbon dioxide equivalent.

(9) "Annual" means with a frequency of once a year; unless otherwise noted, annual events such as reporting requirements will be based on the calendar year.

(10) "API" means the American Petroleum Institute.

(11) "AQMD/APCD" or "air district" means air quality management district or air pollution control district.

(12) "ARB" means the California Air Resources Board.

(13) "Artificial island" is a plot of land or other structure constructed on a body of water to support onshore petroleum or natural gas production.

(14) "Asphalt" means a dark brown-to-black cement-like material obtained by petroleum processing and containing bitumens as the predominant component. It includes crude asphalt as well as the following finished products: cements, fluxes, the asphalt content of emulsions (exclusive of water), and petroleum distillates blended with asphalt to make cutback asphalts.

(15) "Asset-controlling supplier" means any entity that owns or operates electricity generating facilities or serves as an exclusive marketer for certain generating facilities even though it does not own them, and is assigned a supplier-specific identification number and specified source emission factor by ARB for the wholesale electricity procured from its system and imported into California. Asset controlling suppliers include Bonneville Power Administration (BPA) and the two multi-jurisdictional retail providers in California: PacifiCorp and Sierra Pacific Power Company.

(16) "Assigned emissions level" means an amount of emissions, in CO_2e, assigned to the reporting entity by the Executive Officer in the case of a non submitted/non-verified emissions data report or following the issuance of an adverse verification statement.

(17) "Associated gas" or "produced gas" means a natural gas that is produced from gas wells or gas produced in association with the production of crude oil.

(18) "ASTM" means the American Society of Testing and Materials.

(19) "Authorized project designee" means an entity authorized by an Offset Project Operator to act on behalf of the Offset Project Operator.

(20) "Balancing authority" means the responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a balancing authority area, and supports interconnection frequency in real time.

(21) "Balancing authority area" means the collection of generation, transmission, and loads within the metered boundaries of a balancing authority. A balancing authority maintains load-resource balance within this area.

(22) "Barrel" means a volume equal to 42 U.S. gallons.

(23) "Bias" means systematic error, resulting in measurements that will be either consistently low or high relative to the reference value.

(24) "Biodiesel" means a diesel fuel substitute produced from nonpetroleum renewable resources that meet the registration requirements for fuels and fuel additives established by the U.S. Environmental Protection Agency under section 211 of the Clean Air Act. It includes biodiesel that is all of the following:

(A) Registered as a motor vehicle fuel or fuel additive under 40 CFR Part 79;

(B) A mono-alkyl ester;

(C) Meets American Society for Testing and Material designation ASTM D 6751-08 (*Standard Specification for Biodiesel Fuel Blendstock (B100) for Middle Distillate Fuels, 2008*);

(D) Intended for use in engines that are designated to run on conventional diesel fuel; and

(E) Derived from nonpetroleum renewable resources.

(25) "Biogenic portions of CO_2 emissions" means carbon dioxide emissions generated as the result of biomass combustion from combustion units.

(26) "Biomass" means non-fossilized and biodegradable organic material originating from plants, animals and micro-organisms, including products, byproducts, residues and waste from agriculture, forestry and related industries as well as the non-fossilized and biodegradable organic fractions of industrial and municipal wastes, including gases and liquids recovered from the decomposition of non-fossilized and biodegradable organic material. For the purpose of this article, biomass includes both California Renewable Portfolio Standard (RPS) eligible and non-eligible biomass as defined by the California Energy Commission.

(27) "Biomass-derived fuels" or "biomass fuels" or "biofuels" or "biomass-based fuels" means fuels derived from biomass.

(28) "Blendstocks" are petroleum products used for blending or compounding into finished motor gasoline. These include RBOB (reformulated blendstock for oxygenate blending) and CBOB (conventional blendstock for oxygenate blending), but exclude oxygenates, butane, and pentanes plus.

(29) "Blowdown" means the act of emptying or depressurizing a vessel. This may also refer to the discarded material such as blowdown water from a boiler or cooling tower.

(30) "Blowdown vent stack emissions" mean natural gas released due to maintenance and/or blowdown operations including compressor blowdown and emergency shut-down (ESD) system testing.

(31) "Bone dry short ton" means an amount of material that weighs 2,000 pounds at zero percent moisture content.

(32) "Bottom ash" means ash that collects at the bottom of a combustion chamber.

(33) "Bottoming cycle" means a type of cogeneration system in which the energy input to the system is first applied to a useful thermal energy application or process, and at least some of the reject heat emerging from the application or process is then used for electricity production.

(34) "British thermal unit" or "Btu" means the quantity of heat required to raise the temperature of one pound of water by one degree Fahrenheit at about 39.2 degrees Fahrenheit.

(35) "Bulk transfer/terminal system" means a fuel distribution system consisting of refineries, pipelines, vessels, and terminals.

(36) "Busbar" means a power conduit of a facility with electricity generating units that serves as the starting point for the electricity transmission system.

(37) "Business-as-usual scenario" means the set of conditions reasonably expected to occur within the offsets project boundary in the absence of the financial incentives provided by offset credits, taking into account all current laws and regulations, as well as current economic and technological trends.

(38) "Butane" or "n-Butane" is a paraffinic straight-chain hydrocarbon with molecular formula C_4H_{10}.

(39) "Bypass dust" means discarded dust from the bypass system dedusting unit of suspension preheater, precalciner and grate preheater kilns, consisting of fully calcined kiln feed material.

(40) "Calcination" means the thermal decomposition of carbonate minerals, such as calcium carbonate (the principal mineral in limestone) to form calcium oxide in a cement kiln.

(41) "Calcine" means to heat a substance so that it oxidizes or reduces.

(42) "Calendar year" means the time period from January 1 through December 31.

(43) "Calibrated bag" means a flexible, non-elastic, anti-static bag of a calibrated volume that can be affixed to an emitting source such that the emissions inflate the bag to its calibrated volume.

(44) "Cap-and-Trade Regulation" or "Cap-and-Trade Program" means ARB's regulation establishing the California Cap on Greenhouse Gas Emissions and Market-Based Compliance Mechanisms set forth in title 17, California Code of Regulations, Chapter 1, Subchapter 10, article 5 (commencing with section 95800).

(45) "California consignee" means the person or entity in California to whom the shipment is to be delivered.

(46) "California Energy Commission" or "CEC" means the California Energy Resources Conservation and Development Commission.

(47) "Carbon dioxide" or "CO_2" means the most common of the six primary greenhouse gases, consisting on a molecular level of a single carbon atom and two oxygen atoms.

(48) "Carbon dioxide equivalent" or "CO_2 equivalent" or "CO_2e" means the number of metric tons of CO_2 emissions with the same global warming potential as one metric ton of another greenhouse gas.

(49) "Catalyst" means a substance added to a chemical reaction, which facilitates or causes the reaction, and is not consumed by the reaction.

(50) "Cement" means a building material that is produced by heating mixtures of limestone and other minerals or additives at high temperatures in a rotary kiln to form clinker, followed by cooling and grinding with blended additives. Finished cement is a powder used with water, sand and gravel to make concrete and mortar.

(51) "Cement kiln dust" or "CKD" means the fine-grained, solid, highly alkaline waste removed from cement kiln exhaust gas by air pollution control devices. CKD consists of partly calcined kiln feed material and includes all dust from cement kilns and bypass systems including bottom ash and bypass dust.

(52) "Cement plant" means an industrial structure, installation, plant, or building primarily engaged in manufacturing Portland, natural, masonry, pozzolanic, and other hydraulic cements, and typically identified by NAICS code 327310.

(53) "Centrifugal compressor" means any equipment that increases the pressure of a process natural gas by centrifugal action, employing rotating movement of the driven shaft.

(54) "Centrifugal compressor dry seals" means a series of rings around the compressor shaft where it exits the compressor case that operates mechanically under the opposing forces to prevent natural gas from escaping to the atmosphere.

(55) "Centrifugal compressor dry seals emissions" means natural gas released from a dry seal vent pipe and/or the seal face around the rotating shaft where it exits one or both ends of the compressor case.

(56) "Centrifugal compressor wet seal degassing venting emissions" means emissions that occur when the high-pressure oil barriers for centrifugal compressors are depressurized to release absorbed natural gas. High-pressure oil is used as a barrier against escaping gas in centrifugal compressor shafts. Very little gas escapes through the oil barrier, but under high pressure, considerably more gas is absorbed by the oil. The seal oil is purged of the absorbed gas (using heaters, flash tanks, and degassing techniques) and recirculated. The separated gas is commonly vented to the atmosphere.

(57) "Certification" or "certify" refers to the procedure in 40 CFR §98.4(e), as required for reports submitted to ARB under this article.

(58) "City gate" means a location at which natural gas ownership or control passes from one party to another, neither of which is the ultimate consumer. In this article, in keeping with common practice, the term refers to a point or measuring station at which a local gas distribution utility receives gas from a natural gas pipeline company or transmission system. Meters at the city gate station measure the flow of natural gas into the local distribution company system and typically are used to measure local distribution company system sendout to customers.

(59) "Clinker" means the mass of fused material produced in a cement kiln from which finished cement is manufactured by milling and grinding.

(60) "Coal" means all solid fuels classified as anthracite, bituminous, sub-bituminous, or lignite by the American Society for Testing and Materials Designation ASTM D388–05 "Standard Classification of Coals by Rank" (September 2005).

(61) "Coal bed methane" or "CBM" means natural gas which is extracted from underground coal deposits or "beds."

(62) "Cogeneration" means an integrated system that produces electric energy and useful thermal energy for industrial, commercial, or heating and cooling purposes, through the sequential or simultaneous use of the original fuel energy.

(63) "Cogeneration unit" means a unit that produces electric energy and useful thermal energy for industrial, commercial, or heating and cooling purposes, through the sequential [or simultaneous] use of the original fuel energy.

(64) "Coke (petroleum)" means a solid residue consisting mainly of carbon which results from the cracking of petroleum hydrocarbons in processes such as coking and fluid coking. This includes catalyst coke deposited on a catalyst during the refining process which must be burned off in order to regenerate the catalyst.

(65) "Combustion emissions" means greenhouse gas emissions occurring during the exothermic reaction of a fuel with oxygen.

(66) "Combustion source" means a source of emissions resulting from combustion.

(67) "Commercial propane" means liquefied petroleum gas that has any mixture of gasses that can sustain combustion.

(68) "Compliance instrument" means an allowance, offset credit or sector-based offset credit. Each compliance instrument can be used to fulfill a compliance obligation equivalent to up to one metric ton of CO_2e.

(69) "Compliance obligation" means the quantity of verified reported emissions for which a covered entity must submit compliance instruments to ARB.

(70) "Compliance offset protocol" means an offset protocol adopted by the Board.

(71) "Compliance period" means the three-year period for which the compliance obligation is calculated for covered entities pursuant to the Cap-and-Trade Regulation.

(72) "Component" for the purposes of sections 95150 to 95158 of this article means each metal to metal joint or seal of non-welded connection separated by a compression gasket, screwed thread (with or without thread sealing compound), metal to metal compression, or fluid barrier through which natural gas or liquid can escape to the atmosphere.

(73) "Compressor" means any machine for raising the pressure of a natural gas by drawing in low pressure natural gas and discharging significantly higher pressure natural gas.

(74) "Condensate" means hydrocarbon and other liquid separated from natural gas that condenses due to changes in the temperature, pressure, or both, and remains liquid at storage conditions, includes both water and hydrocarbon liquids.

(75) "Conservative" means, in the context of offsets, utilizing project baseline assumptions, emission factors, and methodologies that are more likely than not to understate net GHG reductions or GHG removal enhancements for an offset project to address uncertainties affecting the calculation or measurement of GHG reductions or GHG removal enhancements.

(76) "Conflict of interest" means a situation in which, because of financial or other activities or relationships with other persons or organizations, a person or body is unable or potentially unable to render an impartial verification statement of a potential client's greenhouse gas emissions data report, or the person or body's objectivity in performing verification services is or might be otherwise compromised.

(77) "Consignee" means the same as "California consignee."

(78) "Continuous emissions monitoring system" or "CEMS" means the total equipment required to obtain a continuous measurement of a gas concentration or emission rate from combustion or industrial processes.

(79) "Conventional wells" mean gas wells in producing fields that do not employ hydraulic fracturing to produce commercially viable quantities of natural gas.

(80) "Cracking" means the process of breaking down larger molecules into smaller molecules, utilizing catalysts and/or elevated temperatures and pressures.

(81) "Crude oil" means a mixture of hydrocarbons that exists in the liquid phase in natural underground reservoirs and remains liquid at atmospheric pressure after passing through surface separating facilities. Depending on the characteristics of the crude stream, it may also include any of the following:

(A) Small amounts of hydrocarbons that exist in gaseous phase in natural underground reservoirs but are liquid at atmospheric conditions (temperature and pressure) after being recovered from oil well (casing-head) gas in lease separators and are subsequently commingled with the crude stream without being separately measured. Lease condensate recovered as a liquid from natural gas wells in lease or field separation facilities and later mixed into the crude stream is also included.

(B) Small amounts of non-hydrocarbons, such as sulfur and various metals.

(C) Drip gases, and liquid hydrocarbons produced from tar sands, oil sands, gilsonite, and oil shale.

(D) Petroleum products that are received or produced at a refinery and subsequently injected into a crude supply or reservoir by the same refinery owner or operator.

Liquids produced at natural gas processing plants are excluded. Crude oil is refined to produce a wide array of petroleum products, including heating oils; gasoline, diesel and jet fuels; lubcirants; asphalt; ethane, propane and butane; and many other products used for their energy or chemical content.

(82) "Customer" means a purchaser of electricity not for the purposes of retransmission or resale.

(83) "Data year" means the calendar year in which emissions occurred.

(84) "Delivered electricity" means electricity that was distributed from a PSE and received by a PSE or electricity that was generated, transmitted, and consumed.

(85) "De minimis" means those emissions reported for a source or sources that are calculated using alternatives methods selected by the operator, subject to the limits specified in section 95103(i).

(86) "Dehydrator" means a device in which a liquid absorbent (including desiccant, ethylene glycol, diethylene glycol, or triethylene glycol) directly contacts a natural gas stream to absorb water vapor.

(87) "Dehydrator vent stack emissions" means natural gas released from a natural gas dehydrator system absorbent (typically glycol) reboiler or regenerator, including stripping natural gas and motive natural gas used in absorbent circulation pumps.

(88) "Delayed coking" means a process by which heavier crude oil fractions are thermally decomposed under conditions of elevated temperature and pressure to produce a mixture of lighter oils and petroleum coke.

(89) "De-methanizer" means the natural gas processing unit that separates methane rich residue gas from the heavier hydrocarbons (e.g., ethane, propane, butane, pentane-plus) in feed natural gas stream.

(90) "Desiccant" means a material used in solid-bed dehydrators to remove water from raw natural gas by adsorption. Desiccants include activated alumina, palletized calcium chloride, lithium chloride and granular silica gel material. Wet natural gas is passed through a bed of the granular or pelletized solid adsorbent in these dehydrators. As the wet gas contacts the surface of the particles of desiccant material, water is adsorbed on the surface of these desiccant particles. Passing through the entire desiccant bed, almost all of the water is adsorbed onto the desiccant material, leaving the dry gas to exit the contactor.

(91) "Designated representative" means the person responsible for certifying, signing, and submitting the GHG emissions data report.

(92) "Diesel fuel" means Distillate Fuel No. 1 and Distillate Fuel No. 2, including dyed and nontaxed fuels.

(93) "Distillate fuel oil" means a classification for one of the petroleum fractions produced in conventional distillation operations and from crackers and hydrotreating process units. The generic term distillate fuel oil includes kerosene, diesel fuels (Diesel Fuels No. 1, No. 2, and No. 4), and fuel oils (Fuel Oils No. 1, No. 2, and No. 4).

(94) "Distillate Fuel No. 1" has a maximum distillation temperature of 550°F at the 90 percent recovery point and a minimum flash point of 100°F and includes fuels commonly known as Diesel Fuel No. 1 and Fuel Oil No. 1, but excludes kerosene. This fuel is further subdivided into categories of sulfur content: High Sulfur (greater than 500 ppm), Low Sulfur (less than or equal to 500 ppm and greater than 15 ppm), and Ultra Low Sulfur (less than or equal to 15 ppm).

(95) "Distillate Fuel No. 2" has a minimum and maximum distillation temperature of 540°F and 640°F at the 90 percent recovery point, respectively, and includes fuels commonly known as Diesel Fuel No. 2 and Fuel Oil No. 2. This fuel is further subdivided into categories of sulfur content: High Sulfur (greater than 500 ppm), Low Sulfur (less than or equal to 500 ppm and greater than 15 ppm), and Ultra Low Sulfur (less than or equal to 15 ppm).

(96) "Distillate Fuel No. 4" is a distillate fuel oil made by blending distillate fuel oil and residual fuel oil, with a minimum flash point of 131°F.

(97) "EIA" means the Energy Information Administration. The Energy Information Administration (EIA) is a statistical agency of the United States Department of Energy.

(98) "E&P Tank" means E&P Tank Version 2.0 for Windows software, copyright 1996-1999 by the American Petroleum Institute and the Gas Research Institute (published 2000).

(99) "Electricity consumed on-site" means the amount of electricity generated on-site and used for other operations at the facility, excluding parasitic power required for operation of the electricity generating or cogeneration system. This quantity excludes electricity generated off-site, such as electricity purchased from an electric utility.

(100) "Electricity exporter" means marketers and retail providers that hold title to exported electricity. For electricity delivered between balancing authority areas, the entity that holds title to exported electricity is identified on the

NERC E-tag as the purchasing-selling entity (PSE) on the tag's physical path, with the point of receipt located inside the state of California and the point of delivery located outside the state of California.

(101) "Electricity generating unit" or "EGU" means any combination of physically connected generator(s), reactor(s), boiler(s), combustion turbine(s), or other prime mover(s) operated together to produce electric power.

(102) "Electricity importers" are marketers and retail providers that hold title to imported electricity. For electricity delivered between balancing authority areas, the entity that holds title to delivered electricity is identified on the NERC E-tag as the purchasing-selling entity (PSE) on the tag's physical path, with the point of receipt located outside the state of California and the point of delivery located inside the state of California. Federal and state agencies are subject to the regulatory authority of ARB under this article and include Western Area Power Administration (WAPA), Bonneville Power Administration (BPA), and California Department of Water and Power (DWR). When PSEs are not subject to the regulatory authority of ARB, including tribal nations, the electricity importer is the immediate downstream purchaser or recipient that is subject to the regulatory authority of ARB.

(103) "Electricity transaction" means the purchase, sale, import, export or exchange of electric power.

(104) "Electricity wheeled through California" means electricity that is generated outside the state of California and delivered into California with final point of delivery outside California.

(105) "Emission factor" means a unique value for determining an amount of a greenhouse gas emitted for a given quantity of activity (e.g., metric tons of carbon dioxide emitted per barrel of fossil fuel burned.)

(106) "Emissions" means the release of greenhouse gases into the atmosphere from sources and processes in a facility, including from the combustion of transportation fuels such as natural gas, petroleum products, and natural gas liquids.

(107) "Emissions data report" or "greenhouse gas emissions data report" or "report" means the report prepared by an operator or supplier each year and submitted by electronic means to ARB that provides the information required by this article.

(108) "End user" means a final purchaser of electricity or natural gas not for the purposes of retransmission or resale. In the context of natural gas consumption, an "end user" is the point to which natural gas is delivered for consumption.

(109) "Enforceable" means the authority for ARB to hold a particular party liable and to take appropriate action if any of the provisions of this article are violated.

(110) "Engineering estimation," for the purposes of sections 95150 to 95158 of this article, means an estimate of emissions based on engineering principles applied to measured and/or approximated physical parameters such as dimensions of containment, actual pressures, actual temperatures, and compositions.

(111) "Enhanced oil recovery" or "EOR" means the use of certain methods such as steam (thermal EOR), water flooding or gas injection into existing wells to increase the recovery of crude oil from a reservoir. In the context of this rule, EOR also applies to injection of critical phase carbon dioxide into a crude oil reservoir to enhance the recovery of oil.

(112) "Enterer" means an entity that imports motor vehicle fuel, diesel fuel, fuel ethanol, biodiesel or another biomass-derived fuel or renewable fuel and who is the importer of record under federal customs law or the owner of fuel upon import if the fuel is not subject to federal customs law.

(113) "Entity" means a person, firm, association, organization, partnership, business trust, corporation, limited liability company, company, or government agency.

(114) "Equipment" means any stationary article, machine, or other contrivance, or combination thereof, which may cause the issuance or control the issuance of air contaminants; equipment shall not mean portable equipment, tactical support equipment, or electricity generators designated as backup generators in a permit issued by an air pollution control district or air quality management district.

(115) "Ethane" is a paraffinic hydrocarbon with molecular formula C_2H_6.

(116) "Exchange agreement" means a commitment between electricity market participants to swap energy for energy. Exchange transactions do not involve transfers of payment or receipts of money for the full market value of the energy being exchanged, but may include payment for net differences due to market price differences between the two parts of the transaction or to settle minor imbalances.

(117) "Exclusive marketer" means a marketer that has exclusive rights to market electricity for a generating facility or group of generating facilities.

(118) "Executive Officer" means the Executive Officer of the California Air Resources Board, or his or her delegate.

(119) "Exported electricity" means electricity generated inside the state of California and delivered to serve load outside California. This includes electricity delivered from a point of receipt inside California, to the first point of delivery outside California, having a final point of delivery outside California. Exported electricity does not include electricity generated inside the state of California then transmitted outside of California, but with a final point of delivery inside California. Exported electricity does not include electricity generated inside the state of California that is allocated to serve the California retail customers of a multi-jurisdictional retail provider, consistent with a cost allocation methodology approved by the California Public Utilities Commission and the utility regulatory commission of at least one additional state in which the multi-jurisdictional retail provider provides retail electric service.

(120) "Facility" means any physical property, plant, building, structure, source, or stationary equipment located on one or more contiguous or adjacent properties in actual physical contact or separated solely by a public roadway or other public right-of-way and under common ownership or common control, that emits or may emit any greenhouse gas. Operators of military installations may classify such installations as more than a single facility based on distinct and independent functional groupings within contiguous military properties.

(121) "Feedstock" means the raw material supplied to a process.

(122) "Field," in the context of oil and gas system, means standardized field names and codes of all oil and gas fields identified in the United States as defined by the Energy Information Administration Oil and Gas Field Code Master List.

(123) "Finished motor gasoline" means a complex mixture of volatile hydrocarbons, with or without additives, suitably blended to be used in spark ignition engines. Motor gasoline includes conventional gasoline, reformulated gasoline, and all types of oxygenated gasoline. Gasoline also has seasonal variations in an effort to control ozone levels. This is achieved by lowering the Reid Vapor Pressure (RVP) of gasoline during the summer driving season. Depending on the region of the country the RVP is lowered to below 9.0 psi or 7.8 psi. The RVP may be further lowered by state regulations.

(124) "Firmed and shaped electricity" means electricity that is paired with a variable renewable resource to improve dispatchability and back up the resource to assure customer load is met.

(125) "Flash point" of a volatile liquid is the lowest temperature at which it can vaporize to form an ignitable mixture in air.

(126) "Flare" means a combustion device, whether at ground level or elevated, that uses an open flame to burn combustible gases with combustion air provided by uncontrolled ambient air around the flame.

(127) "Flare combustion" means unburned hydrocarbons including CH_4, CO_2, and N_2O emissions resulting from the incomplete combustion of gas in flares.

(128) "Flare combustion efficiency" means the fraction of natural gas, on a volume or mole basis, that is combusted at the flare burner tip.

(129) "Flow monitor" means a component of the continuous emission monitoring system that measures the volumetric flow of exhaust gas.

(130) "Fluid catalytic cracking unit" or "FCCU" means a process unit in a refinery in which petroleum derivative feedstock is charged and fractured into smaller molecules in the presence of a catalyst, or reacts with a contact material to improve feedstock quality for additional processing, and in which the catalyst or contact material is regenerated by burning off coke and other deposits. The unit includes, but is not limited to, the riser, reactor, regenerator, air blowers, spent catalyst, and all equipment for controlling air pollutant emissions and recovering heat.

(131) "Fluid coking" means a thermal cracking process utilizing the fluidized-solids technique to remove carbon (coke) for continuous conversion of heavy, low-grade oils into lighter products.

(132) "Fluorinated greenhouse gas" means sulfur hexafluoride (SF_6), nitrogen trifluoride (NF_3), and any fluorocarbon except for controlled substances as defined at 40 CFR Part 82, subpart A and substances with vapor pressures of less than 1 mm of Hg absolute at 25°C. With these exceptions, "fluorinated GHG" includes any hydrofluorocarbon, any perfluorocarbon, any fully fluorinated linear, branched or cyclic alkane, ether, tertiary amine or aminoether, any perfluoropolyether, and any hydrofluoropolyether.

(133) "Fossil fuel" means natural gas, petroleum, coal, or any form of solid, liquid, or gaseous fuel derived from such material, including for example, consumer products that are derived from such materials and are combusted.

(134) "Fractionates" means the process of separating natural gas liquids into their constituent liquid products.

(135) "Fractionator" means plants that produce fractionated natural gas liquids (NGLs) extracted from produced natural gas and separate the NGLs individual component products: ethane, propane, butanes and pentane-plus (C5+). Plants that only process natural gas but do not fractionate NGLs further into component products are not considered fractionators. Some fractionators do not process production gas, but instead fractionate bulk

NGLs received from natural gas processors. Some fractionators both process natural gas and fractionate bulk NGLs received from other plants.

(136) "Fuel" means solid, liquid or gaseous combustible material. Volatile organic compounds burned in destruction devices are not fuels unless they can sustain combustion without use of a pilot fuel and such destruction does not result in a commercially useful end product.

(137) "Fuel analytical data" means data collected about fuel usage (including mass, volume, and flow rate) and fuel characteristics (including heating value, carbon content, and molecular weight) to support emissions calculation.

(138) "Fuel characteristic data" means, for the purpose of this article, properties of a fuel used for calculating GHG emissions including carbon content, high heat value, and molecular weight.

(139) "Fuel ethanol" means ethanol that meets ASTM D-4806 (August 2008) specifications for blending with gasolines for use as automotive spark-ignition engine fuel.

(140) "Fuel flowmeter system" means a monitoring system which provides a continuous record of the flow rate of fuel oil or gaseous fuel. A fuel flowmeter system consists of one or more fuel flowmeter components, all necessary auxiliary components (e.g., transmitters, transducers, etc.), and a data acquisition and handling system (DAHS).

(141) "Fuel production facility" means a facility, other than a refinery, in which motor vehicle fuel, diesel fuel or biomass-based fuel is produced.

(142) "Fuel supplier" means a supplier of petroleum products, a supplier of biomass-derived transportation fuels, a supplier of natural gas, or a supplier of liquid petroleum gas as specified in this article.

(143) "Fugitive emissions" means those emissions which are unintentional and could not reasonably pass through a stack, chimney, vent, or other functionally-equivalent opening.

(144) "Fugitive emissions detection" means the process of identifying emissions from equipment, components, and other point sources.

(145) "Fugitive source" means a source of fugitive emissions.

(146) "Full verification" means all verification services as provided in section 95131.

(147) "Gas" means the state of matter distinguished from the solid and liquid states by: relatively low density and viscosity; relatively great expansion and

contraction with changes in pressure and temperature; the ability to diffuse readily; and the spontaneous tendency to become distributed uniformly throughout any container.

(148) "Gas conditions" means the actual temperature, volume, and pressure of a gas sample.

(149) "Gas gathering/booster stations" means centralized stations where produced natural gas from individual wells is co-mingled, compressed for transport to processing plants, transmission and distribution systems, and other gathering/booster stations which co-mingle gas from multiple production gathering/booster stations. Such stations may include gas dehydration, gravity separation of liquids (both hydrocarbon and water), pipeline pig launchers and receivers, and gas powered pneumatic devices.

(150) "Gas to oil ratio" or "GOR" means the ratio of the volume of gas at standard temperature and pressure that is produced from a volume of oil when depressurized to standard temperature and pressure.

(151) "Generation providing entity" or "GPE" means a merchant selling energy from owned, affiliated, or contractually bound generation.

(152) "Generating unit" means any combination of physically connected generator(s), reactor(s), boiler(s), combustion turbine(s), or other prime mover(s) operated together to produce electric power.

(153) "Geothermal" means heat or other associated energy derived from the natural heat of the earth.

(154) "Global warming potential" or "GWP" means the ratio of the time-integrated radiative forcing from the instantaneous release of one kilogram of a trace substance relative to that of one kilogram of a reference gas, i.e., CO_2.

(155) "Greenhouse gas" or "GHG" means carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), sulfur hexafluoride (SF_6), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), hydrocarbons and other fluorinated greenhouse gases as defined in this section.

(156) "Greenhouse gas emission reduction" or "GHG emission reduction" or "greenhouse gas reduction" or "GHG reduction" means a calculated decrease in GHG emissions relative to a project baseline over a specified period of time.

(157) "Greenhouse gas removal enhancement" or "GHG removal" means the calculated total mass of a GHG removed, relative to a project baseline, from the atmosphere over a specified period of time.

(158) "Greenhouse gas reservoir" or "GHG reservoir" means a physical unit or component of the biosphere, geosphere or hydrosphere with the capability to store, accumulate, or release of a GHG removed from the atmosphere by a GHG sink or a GHG captured from a GHG emission source.

(159) "Greenhouse gas sink" or "GHG sink" means a physical unit or process that removes a GHG from the atmosphere.

(160) "Gross generation" or "gross power generated" means the total electrical output of the generating facility or unit, expressed in megawatt hours (MWh) per year.

(161) "HD-5" means a consumer grade of liquefied petroleum gas that contains a minimum of 90% propane, and a maximum of 5% propylene and 5% butanes and ethane.

(162) "HD-10" means liquefied petroleum gas with no more than 10% propylene.

(163) "Heat input rate" means the product (expressed in mmBtu/hr) of the gross calorific value of the fuel (expressed in mmBtu/mass of fuel) and the fuel feed rate into the combustion device (expressed in mass of fuel/hr) and does not include the heat derived from preheated combustion air, recirculated flue gases, or exhaust from other sources.

(164) "High heat value" or "HHV" means the high or gross heat content of the fuel with the heat of vaporization included. The water vapor is assumed to be in a liquid state.

(165) "High-bleed pneumatic devices" are automated flow control devices powered by pressurized natural gas and used for maintaining a process condition such as liquid level, pressure, delta-pressure and temperature. Part of the gas power stream which is regulated by the process condition flows to a valve actuator controller where it vents (bleeds) to the atmosphere at a rate in excess of six standard cubic feet per hour.

(166) "Hydrocarbons" means chemical compounds containing predominantly carbon and hydrogen.

(167) "Hydrofluorocarbons" or "HFCs" means a class of GHGs consisting of hydrogen, fluorine, and carbon.

(168) "Hydrogen" means the lightest of all gases, occurring chiefly in combination with oxygen in water; exists also in acids, bases, alcohols, petroleum, and other hydrocarbons.

(169) "Hydrogen plant" means a facility that produces hydrogen with steam hydrocarbon reforming, partial oxidation of hydrocarbons, or other processes.

(170) "Imported electricity" means electricity generated outside the state of California and delivered to serve load inside the state of California. Imported electricity includes electricity delivered from a point of receipt located outside the state of California, to the first point of delivery located inside the state of California, having a final point of delivery in California. Imported electricity includes electricity imported into California over a multi-jurisdictional retail provider's transmission and distribution system, or electricity imported into California over a balancing authority's transmission and distribution system. Imported electricity includes electricity that is a result of cogeneration located outside the state of California. Imported electricity does not include electricity wheeled through California, which is electricity that is delivered into California with final point of delivery outside California.

(171) "Importer of record" means the owner or purchaser of the goods.

(172) "Inventory position" means a contractual agreement with the terminal operator for the use of the storage facilities and terminaling services for the fuel.

(173) "Intrastate pipeline" means any pipeline wholly within the state of California that is not regulated as a public utility gas corporation by the California Public Utility Commission (CPUC), not a publicly-owned natural gas utility and is not regulated as an interstate pipeline by the Federal Energy Regulatory Commission.

(174) "Interstate pipeline" means any entity that owns or operates a natural gas pipeline delivering natural gas to consumers in the state and is subject to rate regulation by the Federal Energy Regulatory Commission.

(175) "ISO" means the International Organization for Standardization.

(176) "Jurisdiction" means U.S. state or Canadian province. For purposes of this article, "U.S. state" means U.S. State, the District of Columbia, the Commonwealth of Puerto Rico, the Virgin Islands, Guam, and American Samoa and includes the Commonwealth of the Northern Mariana Islands. For purposes of this article, "province" means any Canadian province or territory.

(177) "Kerosene" is a light petroleum distillate with a maximum distillation temperature of 400°F at the 10-percent recovery point, a final maximum boiling point of 572°F, a minimum flash point of 100°F, and a maximum freezing point of -22°F. Included are No. 1-K and No. 2-K, distinguished by maximum sulfur content (0.04 and 0.30 percent of total mass, respectively), as well as all other grades of kerosene called range or stove oil. "Kerosene" does not include kerosene-type jet fuel.

(178) "Kiln" means an oven, furnace, or heated enclosure used for thermally processing a mineral or mineral-based substance.

(179) "Kilowatt hour" or "kWh" means the electrical energy unit of measure equal to one thousand watts of power supplied to, or taken from, an electric circuit steadily for one hour. (A watt is a unit of electrical power equal to one ampere under pressure of one volt, or 1/746 horsepower.)

(180) "Lead verifier" means a person that has met all of the requirements in section 95132(b)(2) and who may act as the lead verifier of a verification team providing verification services or as a lead verifier providing an independent review of verification services rendered.

(181) "Lead verifier independent reviewer" or "independent reviewer" means a lead verifier within a verification body who has not participated in conducting verification services for a reporting entity, offset project developer, or authorized project designee for the current reporting year who provides an independent review of verification services rendered to the reporting entity as required in section 95131.

(182) "Less intensive verification" means the verification services provided in interim years between full verifications; less intensive verification of a reporting entity's emissions data report only requires data checks and document reviews of a reporting entity's emissions data report based on the analysis and risk assessment in the most current sampling plan developed as part of the most current full verification services. This level of verification may only be used if the verifier can provide findings with a reasonable level of assurance.

(183) "Linkage" means the approval of compliance instruments from an external greenhouse gas emission trading system (GHG ETS) to meet compliance obligations under the Cap-and-Trade Regulation, and the reciprocal approval of compliance instruments issued by California to meet compliance obligation in an external GHG ETS.

(184) "Linked jurisdiction" means a jurisdiction which has entered into a linkage agreement pursuant to subarticle 12 of the Cap-and-Trade Regulation.

(185) "Liquefied natural gas" or "LNG" means natural gas (primarily methane) that has been liquefied by reducing its temperature to -260 degrees Fahrenheit at atmospheric pressure.

(186) "Liquefied petroleum gas" or "LPG" means a flammable mixture of hydrocarbon gases used as a fuel. LPG can be mixtures of primarily propane, primarily butane, or mixtures of propane or butane. LPG includes propane grades HD-5, HD-10, and commercial grade propane. LPG also includes both odorized and non-odorized liquid petroleum gas, and is also referred to as LGP, GLP, LP-Gas and propane.

(187) "LNG boiloff gas" means natural gas in the gaseous phase that vents from LNG storage tanks due to ambient heat leakage through the tank insulation and heat energy dissipated in the LNG by internal pumps.

(188) "Local distribution company" or "LDC," for purposes of this article, means a company that owns or operates distribution pipelines, not interstate pipelines, that physically deliver natural gas to end users and includes public utility gas corporations, publicly-owned natural gas utilities and intrastate pipelines.

(189) "Lookback period" means the specified time period of historical data that the operators must use for missing data substitution as required by the regulation.

(190) "Low-bleed pneumatic devices" means automated flow control devices powered by pressurized natural gas and used for maintaining a process condition such as liquid level, pressure, delta-pressure and temperature. Part of the gas power stream which is regulated by the process condition flows to a valve actuator controller where it vents (bleeds) to the atmosphere at a rate equal to or less than six standard cubic feet per hour.

(191) "Low Btu gas" means gases recovered from casing vents, vapor recovery systems, crude oil and petroleum product storage tanks and other parts of the crude oil refining and natural gas production process.

(192) "Marketer" means a purchasing-selling entity that takes title to wholesale electricity and is not a retail provider.

(193) "Market-shifting leakage," in the context of an offset project, means increased GHG emissions or decreased GHG removals outside an offset project's boundary due to the effects of an offset project on an established market for goods or services.

(194) "Material misstatement" means an error, omission, or misreporting, or aggregation of the three, identified in the course of verification services that leads a verification team to believe that an emissions data report contains errors greater than 5 percent in the reported total CO_2e emissions. Material misstatement is calculated separately for each type of data as specified in section 95131(b)(13).

(195) "Maximum potential fuel flow rate" or "maximum fuel consumption rate" means the maximum fuel use rate the source is capable of combusting. When the source consists of multiple units, the maximum potential fuel use rate is the sum of the maximum potential fuel use rates of all the units aggregated as a source.

(196) "Megawatt hour" or "MWh" means the electrical energy unit of measure equal to one million watts of power supplied to, or taken from, an electric circuit steadily for one hour.

(197) "Methane" or "CH_4" means a GHG consisting on the molecular level of a single carbon atom and four hydrogen atoms.

(198) "Metric ton" or "MT" means a common international measurement for mass, equivalent to 2204.6 pounds or 1.1 short tons.

(199) "Missing data period" means a period of time during which a piece of data is not collected, is invalid, or is collected while the measurement device is not in compliance with the applicable quality-assurance requirements. In the context of periodic fuel sampling, missing data period is the entire sampling period (e.g. week, month, or quarter) for which corresponding fuel characteristic data are not obtained. In the context of periodic fuel consumption monitoring and recording, a missing data period consists of the consecutive time intervals (e.g. hours, days, weeks, or months) for which fuel consumption during the time period is not monitored and recorded.

(200) "MMBtu" means million British thermal units.

(201) "Motor gasoline" means a complex mixture of relatively volatile hydrocarbons with or without small quantities of additives, blended to form a fuel suitable for use in spark-ignition engines. Motor gasoline is characterized as having a boiling range of 122 to 158°F at the 10-percent recovery point to 365 to 374°F at the 90-percent recovery point.

(202) "Motor vehicle fuel" means gasoline. It does not include aviation gasoline, jet fuel, diesel fuel, kerosene, liquefied petroleum gas, natural gas in liquid or gaseous form, alcohol, or racing fuel.

(203) "Multi-jurisdictional retail provider" means a retail provider that provides electricity to consumers in California and in one or more other states in a contiguous service territory or from a common power system.

(204) "Municipal solid waste" or "MSW" means solid phase household, commercial/retail, and/or institutional waste, such as yard waste and refuse.

(205) "Nameplate generating capacity" means the maximum rated output of a generator under specific conditions designated by the manufacturer. Generator nameplate capacity is usually indicated in units of kilovolt-amperes (kVA) and in Kilowatts (kW) on a nameplate physically attached to the generator.

(206) "Naphthas" (< 401°F) is a generic term applied to a petroleum fraction with an approximate boiling range between 122°F and 400°F. The naphtha

fraction of crude oil is the raw material for gasoline and is composed largely of paraffinic hydrocarbons.

(207) "Natural gas" means a naturally occurring mixture of hydrocarbon and non-hydrocarbon gases found in geologic formations beneath the earth's surface, of which its constituents include methane, heavier hydrocarbons and carbon dioxide. Natural gas may be field quality (which varies widely) or pipeline quality. For the purposes of this article, the definition of natural gas includes similarly constituted fuels such as field production gas, process gas, and fuel gas.

(208) "Natural gas distribution facility" means the distribution pipelines, metering stations, and regulating stations that are operated by a local distribution company (LDC) that is regulated as a separate operating company by a public utility commission or that are operated as an independent municipally-owned distribution system.

(209) "Natural gas driven pneumatic pump" means a pump that uses pressurized natural gas to move a piston or diaphragm, which pumps liquids on the opposite side of the piston or diaphragm.

(210) "Natural Gas Liquids" or "NGLs " means those hydrocarbons in natural gas that are separated from the gas as liquids through the process of absorption, condensation, adsorption, or other methods at lease separators and field facilities. Generally, such liquids consist of ethane, propane, butanes, and pentanes plus. Bulk NGLs refers to mixtures of NGLs that are sold or delivered as undifferentiated product from natural gas processing plants.

(211) "Natural gas liquid fractionator" means an installation that fractionates natural gas liquids (NGLs) into their constituent liquid products (ethane, propane, normal butane, isobutene or pentanes plus) for supply to downstream facilities.

(212) "NERC E-tag" means North American Electric Reliability Corporation (NERC) energy tag representing transactions on the North American bulk electricity market scheduled to flow between or across balancing authority areas.

(213) "Net generation" or "net power generated" means the gross generation minus station service or unit service power requirements, expressed in megawatt hours (MWh) per year. In the case of cogeneration, this value is intended to include internal consumption of electricity for the purposes of a production process, as well as power put on the grid.

(214) "Nitrous oxide" or "N_2O" means a GHG consisting at the molecular level of two nitrogen atoms and a single oxygen atom.

(215) "Nonconformance" means the failure to use the methods or emission factors specified in this article to calculate emissions, or the failure to meet any other requirements of the regulation.

(216) "Non-submitted/non-verified emissions data report" means an emissions data report that is not submitted to ARB by the applicable reporting deadline, or for which a verification statement has not been issued by the applicable verification deadline.

(217) "North American Industry Classification System (NAICS) code(s)" means the six-digit code(s) that represent the product(s)/activity(s)/service(s) at a facility or supplier as defined in North American Industrial Classification System Manual 2007, available from the U.S. Department of Commerce, National Technical Information Service.

(218) "Offset credit" means a tradable compliance instrument issued or approved by ARB that represents a GHG reduction or GHG removal enhancement of one metric ton of CO_2e. The GHG reduction or GHG removal enhancement must be real, additional, quantifiable permanent, verifiable and enforceable.

(219) "Offset project" means all equipment, materials, items, or actions that are directly related to or have an impact upon GHG reductions, project emissions or GHG removal enhancements within the offset project boundary.

(220) "Offset project boundary" is defined by and includes all GHG emission sources, GHG sinks or GHG reservoirs that are affected by an offset project and under control of the Offset Project Operator or Authorized Project Designee. GHG emissions sources, GHG sinks or GHG reservoirs not under control of the Offset Project Operator or Authorized Project Designee are not included in the offset project boundary.

(221) "Offset project data report" means the report prepared by an Offset Project Operator or Authorized Project Designee each year that provides the information and documentation required by this article or a compliance offset protocol.

(222) "Offset project operator" means the entity(ies) with legal authority to implement the offset project.

(223) "Offset protocol" means a documented set of procedures and requirements to quantify ongoing GHG reductions or GHG removal enhancements achieved by an offset project and calculate the project baseline. Offset protocols specify relevant data collection and monitoring procedures, emission factors and conservatively account for uncertainty and activity-shifting and market-shifting leakage risks associated with an offset project.

(224) "Offshore" means seaward of the terrestrial borders of the United States, including waters subject to the ebb and flow of the tide, as well as adjacent bays, lakes or other normally standing waters, and extending to the outer boundaries of the jurisdiction and control of the United States under the Outer Continental Shelf Lands Act (43 U.S.C. §1331 et seq).

(225) "Offshore petroleum and natural gas production facility" means each platform structure and all associated equipment as defined in section 95150(a)(1) of this article.

(226) "Onshore petroleum and natural gas production facility" means all petroleum or natural gas equipment associated with all petroleum or natural gas production wells under common ownership or common control by an onshore petroleum and natural gas production owner or operator located in a single hydrocarbon basin as defined by the American Association of Petroleum Geologists which is assigned a three digit Geologic Province Code. Where an operating entity holds more than one permit in a basin, then all onshore petroleum and natural gas production equipment relating to all permits in their name in the basin is one onshore petroleum and natural gas production facility.

(227) "Onshore petroleum and natural gas production owner or operator" means the entity who is the permitee to operate petroleum and natural gas wells on the state drilling permit or a state operating permit where no drilling permit is issued by the state, which operates an onshore petroleum and/or natural gas production facility. Where more than one entity are permitees on the state drilling permit, or operating permit where no drilling permit is issued by the state, the permitted entities for the joint facility must designate one entity to report all emissions from the joint facility.

(228) "Operating pressure" means the containment pressure that characterizes the normal state of gas or liquid inside a particular process, pipeline, vessel or tank.

(229) "Operational control" for a facility subject to this article means the authority to introduce and implement operating, environmental, health and safety policies. In any circumstance where this authority is shared among multiple entities, the entity holding the permit to operate from the local air pollution control district or air quality management district is considered to have operational control for purposes of this article.

(230) "Operator" means the entity, including an owner, having operational control of a facility. For onshore petroleum and natural gas production, the operator is the operating entity listed on the state well drilling permit, or a state operating permit for wells where no drilling permit is issued by the state.

(231) "Other Biomass-Derived Fuel" means a biomass-derived fuel for which a reporting entity is required to hold a compliance obligation under title 17, California Code of Regulations, section 95852(g).

(232) "Outer Continental Shelf" means all submerged lands lying seaward and outside of the area of lands beneath navigable waters as defined in 43 U.S.C. § 1301, and of which the subsoil and seabed appertain to the United States and are subject to its jurisdiction and control.

(233) "Perfluorocarbons" or "PFCs" means a class of greenhouse gases consisting on the molecular level of carbon and fluorine.

(234) "Permanent" means, in the context of offset credits, either that GHG reductions or GHG removal enhancements are not reversible, or when GHG reductions or GHG removal enhancements may be reversible, that mechanisms are in place to replace any reversed GHG emission reductions or GHG removal enhancements to ensure that all credited reductions endure for a period that is comparable to the atmospheric lifetime of an anthropogenic CO_2 emission.

(235) "Petroleum" means oil removed from the earth and the oil derived from tar sands and shale.

(236) "Petroleum coke" means a black solid residue, obtained mainly by cracking and carbonizing of petroleum derived feedstocks, vacuum bottoms, tar and pitches in processes such as delayed coking or fluid coking. It consists mainly of carbon (90 to 95 percent), has low ash content, and may be used as a feedstock in coke ovens. This product is also known as marketable coke or catalyst coke.

(237) "Petroleum refinery" or "refinery" means any facility engaged in producing gasoline, gasoline blending stocks, naphtha, kerosene, distillate fuel oils, residual fuel oils, lubricants, or asphalt (bitumen) through distillation of petroleum or through redistillation, cracking, or reforming of unfinished petroleum derivatives. Facilities that distill only pipeline transmix (off-spec material created when different specification products mix during pipeline transportation) are not petroleum refineries, regardless of the products produced.

(238) "Physical address," with respect to a United States parent company as defined in this section, means the street address, city, State and zip code of that company's physical location.

(239) "Pipeline quality natural gas" means natural gas having a high heat value greater than 970 Btu/scf and equal to or less than 1,100 Btu/scf, and which is at least ninety percent methane by volume, and which is less than five percent carbon dioxide by volume.

(240) "Point of delivery" means the point on an electricity transmission or distribution system where a deliverer makes electricity available to a receiver, or available to serve load. This point can be an interconnection with another system or a substation where the transmission provider's transmission and distribution systems are connected to another system, or a distribution substation where electricity is imported into California over a multi-jurisdictional retail provider's distribution system.

(241) "Point of receipt" the point on an electricity transmission or distribution system where an electricity receiver receives electricity from a deliverer. This point can be an interconnection with another system or a substation where the transmission provider's transmission and distribution systems are connected to another system.

(242) "Point source" means any separately identifiable stationary point from which greenhouse gases are emitted.

(243) "Portable" means designed and capable of being carried or moved from one location to another. Indications of portability include wheels, skids, carrying handles, dolly, trailer, or platform. Equipment is not portable if any one of the following conditions exists:

(A) The equipment is attached to a foundation.

(B) The equipment or a replacement resides at the same location for more than 12 consecutive months.

(C) The equipment is located at a seasonal facility and operates during the full annual operating period of the seasonal facility, remains at the facility for at least two years, and operates at that facility for at least three months each year.

(D) The equipment is moved from one location to another in an attempt to circumvent the portable residence time requirements of this definition.

(244) "Portland cement" means hydraulic cement (cement that not only hardens by reacting with water but also forms a water-resistant product) produced by pulverizing clinkers consisting essentially of hydraulic calcium silicates, usually containing one or more of the forms of calcium sulfate as an inter-ground addition.

(245) "Position Holder" means an entity that holds an inventory position in motor vehicle fuel, ethanol, distillate fuel, biodiesel, or renewable diesel as reflected in the records of the terminal operator or a terminal operator that owns motor vehicle fuel or diesel fuel in its terminal.

(246) "Positive verification statement" means a verification statement rendered by a verification body attesting that the verification body can say with reasonable assurance that the submitted emissions data report is free of material misstatement and that the emissions data report conforms to the requirements of this article.

(247) "Power" means electricity, except where the context makes clear that another meaning is intended.

(248) "Power contract" means a written document arranging for the procurement of electricity. Power contracts may be, but are not limited to, power purchase agreements and tariff provisions.

(249) "Primary fuel" means the main fuel type (expressed in mmBtu) consumed by a unit for the applicable calendar year.

(250) "Prime mover" means the type of equipment such as an engine or water wheel that drives an electric generator. "Prime movers" include, but are not limited to, reciprocating engines, combustion or gas turbines, steam turbines, microturbines, and fuel cells.

(251) "Process" means the intentional or unintentional reactions between substances or their transformation, including, but not limited to, the chemical or electrolytic reduction or metal ores, the thermal decomposition of substances, and the formation of substances for use as product or feedstock.

(252) "Process emissions" means the emissions from industrial processes (e.g., cement production, ammonia production) involving chemical or physical transformations other than fuel combustion. For example, the calcination of carbonates in a kiln during cement production or the oxidation of methane in an ammonia process results in the release of process CO_2 emissions to the atmosphere. Emissions from fuel combustion to provide process heat are not part of process emissions, whether the combustion is internal or external to the process equipment.

(253) "Process gas" means any gas generated by an industrial process such as petroleum refining.

(254) "Process vent" means an opening where a gas stream is continuously or periodically discharged during normal operation.

(255) "Producer" means a person who owns, leases, operates, controls or supervises a California production facility.

(256) "Professional judgment" means the ability to render sound decisions based on professional qualifications and relevant greenhouse gas accounting and auditing experience.

(257) "Project baseline" means, in the context of a specific offset project, a conservative estimate of business-as-usual GHG emission reductions or GHG removal enhancements for the offset project's GHG emission sources, GHG sinks, or GHG reservoirs within the offset project boundary.

(258) "Propane" is a paraffinic hydrocarbon with molecular formula C_3H_8.

(259) "Public utility gas corporation" is a gas corporation defined in California Public Utilities Code section 222 that is also a public utility as defined in California Public Utilities Code section 216.

(260) "Publicly-owned natural gas utility" means a municipality or municipal corporation, a municipal utility district, a public utility district, or a joint powers authority that includes one or more of these agencies that furnishes natural gas services to end users.

(261) "Pump" means a device used to raise pressure, drive, or increase flow of liquid streams in closed or open conduits.

(262) "Pump seal emissions" means hydrocarbon gas released from the seal face between the pump internal chamber and the atmosphere.

(263) "Pump seals" means any seal on a pump drive shaft used to keep methane and/or carbon dioxide containing light liquids from escaping the inside of a pump case to the atmosphere.

(264) "Purchasing-selling entity" or "PSE" means the functional entity that purchases or sells, and takes title to energy, capacity, and reliability related services. A PSE is identified on a NERC E-tag for each physical path segment.

(265) "Pure" means consisting of at least 97 percent by mass of a specified substance. For facilities burning biomass fuels, this means the fraction of biomass carbon accounts for at least 97 percent of the total amount of carbon in the fuel burned at the facility.

(266) "Qualified positive verification statement" means a statement rendered by a verification body attesting that the verification body can say with reasonable assurance that the submitted emissions data report is free of material misstatement, but the emissions data report may include one or more nonconformance(s) with the requirements of this article which do not result in a material misstatement.

(267) "QA/QC" means quality assurance and quality control.

(268) "Quality-assured data" or "quality-assured value" means the data are obtained from a monitoring system that is operating within the performance specifications and the quality assurance/quality control procedures set forth

in the applicable rules, such as 40 CFR Part 60 or Part 75, without unscheduled maintenance, repair, or adjustment.

(269) "Quantifiable" means, in the context of offset projects, the ability to accurately measure and calculate GHG reductions or GHG removal enhancements relative to a project baseline in a reliable and replicable manner for all GHG emission sources, GHG sinks or GHG reservoirs included within the offset project boundary, while accounting for uncertainty, activity-shifting leakage and market-shifting leakage.

(270) "Rack" means a mechanism for delivering motor vehicle fuel or diesel from a refinery or terminal into a truck, trailer, railroad car, or other means of non-bulk transfer.

(271) "Real" means, in the context of offset projects, that GHG reductions or GHG enhancements result from a demonstrable action or set of actions, and are quantified using appropriate, accurate and conservative methodologies that account for all GHG emissions sources, GHG sinks, and GHG reservoirs within the offset project boundary and account for uncertainty and the potential for activity-shifting leakage and market-shifting leakage.

(272) "Reasonable assurance" means a high degree of confidence that submitted data and statements are valid.

(273) "Reciprocating compressor" means a piece of equipment that increases the pressure of a process natural gas by positive displacement, employing linear movement of a shaft driving a piston in a cylinder.

(274) "Recycled" refers to a material that is reused or reclaimed.

(275) "Reciprocating compressor rod packing" means a series of flexible rings in machined metal cups that fit around the reciprocating compressor piston rod to create a seal limiting the amount of compressed natural gas that escapes to the atmosphere.

(276) "Re-condenser" means heat exchangers that cool compressed boil-off gas to a temperature that will condense natural gas to a liquid.

(277) "Refinery fuel gas" or "still gas" means gas generated at a petroleum refinery or any gas generated by a refinery process unit, and that is combusted separately or in any combination with any type of gas or used as a chemical feedstock.

(278) "Reformulated Gasoline Blendstock for Oxygenate Blending" or "RBOB" has the same meaning as defined in title 13 of the California Code of Regulations, section 2260(a).

(279) "Relative Accuracy Test Audit" means a method of determining the correlation of continuous emissions monitoring system data to simultaneously collected reference method test data, such as required in 40 CFR Part 60 and 40 CFR Part 75.

(280) "Renewable diesel" means a motor vehicle fuel or fuel additive that is all of the following:

(A) Registered as a motor vehicle fuel or fuel additive under 40 CFR Part 79;

(B) Not a mono-alkyl ester;

(C) Intended for use in engines that are designed to run on conventional diesel fuel; and

(D) Derived from nonpetroleum renewable resources.

(281) "Renewable energy" means energy from sources that constantly renew themselves or that are regarded as practically inexhaustible. Renewable energy includes energy derived from solar, wind, geothermal, hydroelectric, wood, biomass, tidal power, sea currents, and ocean thermal gradients.

(282) "Reporting entity" means a facility operator, supplier, or electric power entity subject to the requirements of this article.

(283) "Reporting period" means the calendar year which coincides with the data year for the GHG report.

(284) "Reporting year" or "report year" means data year.

(285) "Reservoir" means a porous and permeable underground natural formation containing significant quantities of hydrocarbon liquids and/or gases. A reservoir is characterized by a single natural pressure system.

(286) "Residual fuel oil" means a general classification for the heavier oils, known as No. 5 and No. 6 fuel oils, that remain after the distillate fuel oils and lighter hydrocarbons are distilled away in refinery operations.

(287) "Retail provider" means an entity that provides electricity to retail end users in California and is an electric corporation as defined in Public Utilities Code section 218, electric service provider as defined in Public Utilities Code section 218.3, local publicly owned electric utility as defined in Public Utilities Code section 224.3, a community choice aggregator as defined in Public Utilities Code section 331.1, or the Western Area Power Administration. For purposes of this article, electrical cooperatives, as defined by Public Utilities Code section 2776, are excluded.

(288) "Retail sales" means electricity sold to retail end users.

(289) "Retail end-use customer" or "retail end user" means a residential, commercial, agricultural, or industrial electric customer who buys electricity to be consumed as a final product and not for resale.

(290) "Sales oil" means produced crude oil or condensate measured at the production lease automatic custody transfer (LACT) meter or custody transfer meter tank gauge.

(291) "Sector" means a broad industrial categorization such as specified in section 95101.

(292) "Sector-based offset credit" means a credit issued from a sector-based crediting program once the crediting baseline for a sector has been reached. For the limited purposes of this definition, "sector" means a group or subgroup of an economic activity - or a group of economic activities - as in "service sector" - or a cross-section of a group of economic activities - as in "informal sector."

(293) "Sector-based crediting program" is a GHG emissions reduction crediting mechanism established by a country, region, or subnational jurisdiction in a developing country and covering a particular economic sector within that jurisdiction. A program's performance is based on achievement toward an emissions reduction target for the particular sector within the boundary of the jurisdiction and beyond. Responsibility for reducing emissions in a sector-based crediting program is shared between GHG mitigation policies and activities specific to that sector that exceed legal requirements and market mechanisms. For the limited purposes of this definition, "sector" means a group or subgroup of an economic activity - or a group of economic activities - as in "service sector" - or a cross-section of a group of economic activities - as in "informal sector."

(294) "Separator" means a vessel in which streams of multiple phases are gravity separated into individual streams of single phase.

(295) "Short ton" means a common international measurement for mass, equivalent to 2,000 pounds.

(296) "Shutdown" means the cessation of operation of an emission source for any purpose.

(297) "Sour natural gas" means natural gas that contains significant concentrations of hydrogen sulfide and/or carbon dioxide that exceed the concentrations specified for commercially saleable natural gas delivered from transmission and distribution pipelines.

(298) "Source" means greenhouse gas source; any physical unit, process, or other use or activity that releases a greenhouse gas into the atmosphere.

(299) "Specified source of electricity" or "specified source" means a facility or unit which is permitted to be claimed as the source of imported electricity delivered by an electricity importer. The electricity importer must have either full or partial ownership in the facility/unit or a written contract to procure electricity generated by that facility/unit. Specified facilities/units include cogeneration systems. Specified source also means electricity procured from an asset-controlling supplier recognized by the ARB.

(300) "Standard cubic foot" or "scf" is a measure of quantity of gas, equal to a cubic foot of volume at 60 degrees Fahrenheit and either 14.696 pounds per square inch (1 atm) or 14.73 PSI (30 inches Hg) of pressure.

(301) "Standard conditions" or "standard temperature and pressure (STP)" means 68 degrees Fahrenheit and 14.7 pounds per square inch absolute.

(302) "SSM" means periods of startup, shutdown and malfunction during flare operations.

(303) "Stationary" means neither portable nor self propelled, and operated at a single facility.

(304) "Storage tank" means any tank, other container, or reservoir used for the storage of organic liquids, excluding tanks that are permanently affixed to mobile vehicles such as railroad tank cars, tanker trucks or ocean vessels.

(305) "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.

(306) "Sulfur hexafluoride" or "SF_6" means a GHG consisting on the molecular level of a single sulfur atom and six fluorine atoms.

(307) "Supplemental firing" means an energy input to the cogeneration facility used only in the thermal process of a topping-cycle plant, or in the electric generating or manufacturing process of a bottoming-cycle cogeneration facility.

(308) "Supplier" means a producer, importer, or exporter of a fossil fuel or an industrial greenhouse gas.

(309) "Sweet Gas" means natural gas with low concentrations of hydrogen sulfide (H_2S) and/or carbon dioxide (CO_2) that does not require (or has already had) acid gas treatment to meet pipeline corrosion-prevention specifications for transmission and distribution.

(310) "Tactical support equipment" is as defined in Title 17, California Code of Regulations, section 93116.2(a)(36).

(311) "Terminal" means a motor vehicle fuel or diesel fuel storage and distribution facility that is supplied by pipeline or vessel, and from which motor vehicle fuel may be removed at a rack. "Terminal" includes a fuel production facility where motor vehicle fuel is produced and stored and from which motor vehicle fuel may be removed at a rack.

(312) "Terminal Operator" means any entity that owns, operates or otherwise controls a terminal that is supplied by pipeline or vessel and from which accountable fuel products may be removed at a rack.

(313) "Thermal energy" means the thermal output produced by a combustion source used directly as part of a manufacturing process but not used to produce electricity.

(314) "Tier" means the level of calculation method from 40 CFR §98.33 that is required for a stationary combustion source in section 95115 of this article.

(315) "Tier 1" means a stationary combustion calculation method that applies default values for emission factors and high heat value to generate an emissions estimate, as specified in 40 CFR §98.33.

(316) "Tier 2" means a stationary combustion calculation method that applies a default value for an emission factor and a fuel's measured high heat value (or a boiler efficiency for steam-generating solid fuels) to generate an emissions estimate, as specified in 40 CFR §98.33.

(317) "Tier 3" means a stationary combustion calculation method that utilizes a fuel's measured carbon content to generate an emissions estimate, as specified in 40 CFR §98.33.

(318) "Tier 4" means a stationary combustion calculation method that utilizes quality-assured data from a continuous emission monitoring system to generate an emissions estimate, as specified in 40 CFR §98.33. This method may also capture process emissions from a common stack.

(319) "Topping cycle" means a type of cogeneration system in which the energy input to the plant is first used to produce electricity, and at least some of the reject heat from the electricity production process is then used to provide useful thermal output.

(320) "Transmission pipeline" means a high pressure cross country pipeline transporting sellable quality natural gas from production or natural gas processing to natural gas distribution pressure let-down, metering, regulating stations where the natural gas is typically odorized before delivery to customers.

(321) "Tribal nation" means those Native American tribes in the United States and listed in the Federal Register.

(322) "Turbine meter" means a flow meter in which a gas or liquid flow rate through the calibrated tube spins a turbine from which the spin rate is detected and calibrated to measure the fluid flow rate.

(323) "Uncertainty" means the degree to which data or a data system is deemed to be indefinite or unreliable.

(324) "Uncontrolled blowdown system" means the use of a blowdown procedure that does not result in the recovery of emissions for flaring or re-injection.

(325) "Unconventional wells" means gas wells in producing fields that employ hydraulic fracturing to enhance gas production volumes.

(326) "United States" means the 50 States, the District of Columbia, the Commonwealth of Puerto Rico, American Samoa, the Virgin Islands, Guam, and any other Commonwealth, territory or possession of the United States, as well as the territorial sea as defined by Presidential Proclamation No. 5928.

(327) "United States parent company(s)" mean the highest-level United States company(s) with an ownership interest in the reporting entity as of December 31 of the reporting year.

(328) "Unspecified source of electricity" or "unspecified source" means electricity generation that cannot be matched to a specific facility or unit that generates electricity or matched to an asset-controlling supplier recognized by the ARB. Unspecified sources contribute to the bulk system power pool and typically are dispatchable, marginal resources that do not serve baseload.

(329) "U.S. EPA" means the United States Environmental Protection Agency.

(330) "Useful thermal output" means the thermal energy made available in a cogeneration system for use in any industrial or commercial process, heating or cooling application, or delivered to other end users, i.e., total thermal energy made available for processes and applications other than electrical generation.

(331) "Vapor recovery system" means any equipment located at the source of potential gas emissions to the atmosphere or to a flare, that is composed of piping, connections, and, if necessary, flow-inducing devices, and that is used for routing the gas back into the process as a product and/or fuel.

(332) "Vaporization unit" means a process unit that performs controlled heat input to vaporize LNG to supply transmission and distribution pipelines or consumers with natural gas.

(333) "Variable renewable resource" means run-of-river hydroelectric, solar, or wind energy that requires firming and shaping to meet load requirements.

(334) "Vented emissions" means intentional or designed releases of CH_4 or CO_2 containing natural gas or hydrocarbon gas (not including stationary combustion flue gas), including process designed flow to the atmosphere through seals or vent pipes, equipment blowdown for maintenance, and direct venting of gas used to power equipment (such as pneumatic devices).

(335) "Verifiable," in the context of offset projects, means that an offset project data report assertion is well documented and transparent such that it lends itself to an objective review by an accredited verification body.

(336) "Verification" means a systematic, independent and documented process for evaluation of a reporting entity's emissions data report against ARB's reporting procedures and methods for calculation and reporting GHG emissions.

(337) "Verification body" means a firm accredited by ARB that is able to render a verification statement and provide verification services for reporting entities subject to reporting under this article.

(338) "Verification services" means services provided during verification as specified in section 95131 beginning with the development of the verification plan or first site visit, including but not limited to reviewing a reporting entity's emissions data report, verifying its accuracy according to the standards specified in this article, assessing the reporting entity's compliance with this article, and submitting a verification statement to the ARB.

(339) "Verification statement" means the final statement rendered by a verification body attesting whether a reporting entity's emissions data report is free of material misstatement, and whether the emissions data report conforms to the requirements of this article.

(340) "Verification team" means all of those working for a verification body, including all subcontractors, to provide verification services for a reporting entity.

(341) "Verified emissions data report" means an emissions data report that has been reviewed by a third-party verifier and has a verification statement accepted by the ARB.

(342) "Verifier" means an individual accredited by ARB to carry out verification services as specified in section 95131.

(343) "Verifier review" means a verifier conducts all reviews and services in section 95131, except the material misstatement assessment under section 95131(b)(14). If some of the sources are selected for data checks based on the sampling plan, the verifier will check for conformance with the requirements of this article.

(344) "Volatile organic compound" or "VOC" means any volatile compound of carbon, excluding carbon monoxide, carbon dioxide, carbonic acid, metallic carbides or carbonates, and ammonium carbonate, which participates in atmospheric photochemical reactions.

(345) "Weighted monthly average" means the sum of the products of two values measured during the same time period divided by the sum of the values not being averaged. For weighted average HHV it would be the sum of the products of volume and HHV measured during the same time period divided by the sum of the volumes.

(346) "Well completions" means a process that allows for the flow of petroleum or natural gas from newly drilled wells to expel drilling and reservoir fluids and test the reservoir flow characteristics. This process includes high-rate back-flow of injected water and sand used to fracture and prop-open fractures in low permeability gas reservoirs.

(347) "Well workover" means the performance of one or more of a variety of remedial operations on producing oil and gas wells to try to increase production. This process also includes high-rate back-flow of injected water and sand used to re-fracture and prop-open new fractures in existing low permeability gas reservoirs.

(348) "Wellhead" means the piping, casing, tubing and connected valves protruding above the Earth's surface for an oil and/or natural gas well. The wellhead ends where the flow line connects to a wellhead valve.

(349) "Wet natural gas" means natural gas in which water vapor exceeds the concentration specified for commercially saleable natural gas delivered from transmission and distribution pipelines. This input stream to a natural gas dehydrator is referred to as "wet gas".

(350) "Wholesale sales" means sales to other LDCs.

NOTE: Authority cited: Sections 39600, 39601, 39607, 39607.4, 41511, 38510, and 38530, Health and Safety Code. Reference: Sections 39600, 41511, and 38530, Health and Safety Code.

§ 95103. Greenhouse Gas Reporting Requirements.

The facilities, suppliers, and entities specified in section 95101 must monitor emissions and submit emissions data reports to the Air Resources Board following the requirements specified in 40 CFR §98.3 and §98.4, except as otherwise provided in this section.

(a) *Abbreviated Reporting for Facilities with Emissions Below 25,000 Metric Tons of CO_2e.* The facility operator without a compliance obligation under the Cap-and-Trade Regulation during any year of the current three-year compliance period, who is also not subject to the reporting requirements of 40 CFR Part 98 and whose total stationary and process emissions are below 25,000 metric tons of CO_2e in 2011 and each subsequent year, may submit abbreviated emissions data reports under this article. This provision does not apply to suppliers or electric power entities. Abbreviated reports must include the following information:

(1) Facility name, assigned ARB identification number, physical street address including the city, state and zip code, air basin, air district, county, and geographic location.
(2) Total facility GHG emissions aggregated for all stationary fuel combustion units and calculated according to any method available by fuel type in 40 CFR §98.33(a), expressed in metric tons of total CO_2, CO_2 from biomass-derived fuels, CH_4, and N_2O.
(3) If applicable, GHG emissions for each process source type found in 40 CFR Part 98 that was in operation at the facility during the period covered by the report. Emissions must be determined according to any method specified for that process emissions type in 40 CFR Part 98, and expressed in metric tons of CO_2, CO_2 from bio-based feedstock, CH_4, N_2O, and total CO_2e as applicable. At facilities where a continuous emissions monitoring system (CEMS) is installed and operated according to federal, state or local requirements, process emissions may be reported in combination with stationary combustion emissions, but fuel use by fuel type must be separately reported in the units specified below.
(4) Identification of the methods chosen for determining emissions.
(5) Any facility operating data or process information used for the GHG emission calculations, including fuel use by fuel type, reported in million standard cubic feet for gaseous fuels, gallons for liquid fuels, short tons for solid fuels, and bone-dry short tons for biomass-derived solid fuels. If applicable, include high heat values and carbon content values used to calculate emissions.
(6) For facilities with on-site electricity generation or cogeneration, the information specified in section 95112(a)-(b) of this article.
(7) A signed and dated certification statement provided by the designated representative of the owner or operator, according to the requirements of 40 CFR §98.4(e)(1).

(b) Abbreviated emissions data reports submitted under this provision must be certified no later than June 1 of each calendar year. Subsequent revisions according to the requirements of 40 CFR §98.3(h) must be submitted only if cumulative errors are found to exceed 5 percent of total CO_2e emissions, or if error correction would cause the emissions total to exceed 25,000 metric tons of CO_2e, in which case a report that meets the full requirements of this article must be submitted.

(c) For abbreviated reports submitted under this provision, records must be kept according to the requirements of 40 CFR 98.3(g), except that a written GHG Monitoring Plan is not required.

(d) An abbreviated emissions data report is not subject to the third-party verification requirements of this article.

(e) *Reporting Deadlines.* Except as otherwise specified in this paragraph, each facility operator or supplier must submit an emissions data report for the previous calendar year no later than April 1 of each calendar year. Each electric power entity must submit an emissions data report for the previous calendar year no later than June 1 of each calendar year. The operator submitting an abbreviated report under the provisions of section 95103(a)-(d) must submit the abbreviated report no later than June 1 of each calendar year.

(f) *Verification Requirement and Deadlines.* Each reporting entity submitting an emissions data report for the previous calendar year that indicates emissions equaled or exceeded 25,000 metric tons of CO_2e, including CO_2 from biomass-derived fuels and geothermal sources, and each reporting entity that has or has had a compliance obligation under the Cap-and-Trade Regulation in any year of the current three-year compliance period, must obtain third-party verification services for that report from a verification body that meets the requirements specified in Subarticle 4 of this article. Such services must be completed and a verification statement submitted by the verification body to the Executive Officer by September 1 each year for operators and suppliers, and by October 1 each year for electric power entities. Each reporting entity must ensure that this verification statement is submitted by the applicable deadline specified in this paragraph. Contracting with a verification body without providing sufficient time to complete the verification statement by the applicable deadline will not excuse the reporting entity from this responsibility. These requirements are additional to the requirements in 40 CFR §98.3(f).

(g) *Non-submitted/Non-verified Emissions Data Reports.* When a reporting entity that holds a compliance obligation under the Cap-and-Trade Regulation fails to submit an emissions data report or fails to obtain a positive or qualified positive verification statement by the applicable deadline, the Executive Officer shall develop an assigned emissions level for the reporting entity as set forth in section 95131(c)(5)(A)-(B).

(h) *Reporting in 2012.* For emissions data reports due in 2012, in cases where monitoring equipment and procedures were not in place in 2011 to enable reporting under the full specifications of this article, operators and suppliers must report 2011 emissions using monitoring and calculation methods that are applicable to them from 40 CFR Part 98. Electric power entities must report 2011 electricity transactions (MWh) and emissions (MT of CO_2e) under the full specifications of this article as applicable in 2012.

(i) *Calculation and Reporting of* De Minimis *Emissions.* A facility operator may designate as *de minimis* a portion of GHG emissions, representing no more than 3 percent of a facility's total CO_2 equivalent emissions (including emissions from biomass-derived fuels and feedstock), not to exceed 20,000 metric tons of CO_2e. The operator may estimate *de minimis* emissions using alternative methods of the operator's choosing, subject to the concurrence of the verification body that the methods used are reasonable, not biased toward significant underestimation or overestimation of emissions, and unlikely to exceed the *de minimis* limits. Where these emissions are required to be reported by 40 CFR Part 98, the operator must calculate and report them consistent with the report submitted to U.S. EPA under those requirements. The operator must separately identify and include in the emissions data report the emissions from designated *de minimis* sources. The operator must determine CO_2 equivalence according to the global warming potentials provided in Table A-1 of 40 CFR Part 98.

(j) *Calculating, Reporting, and Verifying Emissions from Biomass-Derived Fuels.* The operator or supplier must separately identify, calculate, and report all direct emission of CO_2 resulting from the combustion of biomass-derived fuels as specified in sections 95115 for facilities, and sections 95121-95122 for suppliers. Biomass-derived fuel emissions must be identified by the source of fuel as described in title 17, California Code of Regulations, section 95852.2. A biomass-derived fuel not listed in that section will be identified as an Other Biomass-Derived Fuel and the reporting entity will be required to hold a compliance obligation under title 17, California Code of Regulations, section 95852.1. For a fuel listed under title 17, California Code of Regulations, section 95852.2, reporting entities must also meet the verification requirements in section 95131(i) of this article, or the fuel must be identified as an Other Biomass-Derived Fuel and be subject to a compliance obligation under title 17, California Code of Regulations, section 95852.1. The responsibility for obtaining verification of a biomass-derived fuel falls on the entity that is claiming there is not a compliance obligation for the fuel, as indicated in section 95852.2 of the Cap-and-Trade Regulation.

(k) *Measurement Accuracy Requirement.* The operator or supplier submitting an emissions data report with fossil fuel emissions greater than or equal to 25,000 metric tons of CO_2e, and each operator or supplier with a compliance obligation under the Cap-and-Trade Regulation in any year of the current three-year compliance period, must meet the requirements of 40 CFR §98.3(i) for calibration and measurement device accuracy. The operator or supplier with infrequent

outages as specified at 40 CFR §98.3(i)(6) who documents in the monitoring plan a calibration postponement after January 1, 2012 must submit to the Executive Officer a request for postponement, within 30 days of the postponement or the effective date of this article, whichever occurs last. The request must include an explanation of the reasons for the postponement, the date when the calibration will be completed, or a demonstration of meter accuracy in the absence of calibration. Such postponement will be subject to the approval of the Executive Officer.

(l) *Weekly Fuel Monitoring.* In addition to the requirements specified in 40 CFR §98.3(g)(5), as a part of the GHG Monitoring Plan the operator must monitor fuel measurement equipment and maintain records of its proper operation by recording fuel consumption quantities at least weekly, where such equipment is used to calculate GHG emissions. The records of fuel consumption must be sufficient for the application of the missing data substitution procedure in section 95129(d)(2) in the event that the use of that procedure becomes necessary.

(m) *Changes in Methodology.* Except as specified below, where this article permits a choice between different methods for the monitoring and calculation of GHGs, the operator or supplier must make this choice by January 1, 2013, and continue to use the method chosen for all future emissions data reports, unless the use of an alternative calculation method is approved in advance by the Executive Officer.

(1) The operator or supplier is permitted to permanently improve the emissions calculation method after January 1, 2013 through a change to a higher-tier monitoring or calculation method, such as the addition of a continuous emissions monitoring system.
(2) The operator or supplier is permitted to temporarily modify the emissions monitoring or calculation method when consistent with and necessary to comply with the missing data provisions of this article.
(3) When proposing a change in monitoring or calculation method, an operator or supplier must indicate why the change in method is being proposed, and provide a demonstration of differences in estimated emissions under the two methods.
(4) When permitted, a change in method must be made after the completion of monitoring for a data year, and not for a portion of a data year except where necessary to comply with section 95129 and other missing data substitution provisions of this article.

(n) *Addresses.* The following address shall be substituted for the addresses provided in 40 CFR §98.9 for both U.S. mail and package deliveries:

Executive Officer
Attn: Emission Inventory Branch
California Air Resources Board
P.O. Box 2815
Sacramento, CA 95812

NOTE: Authority cited: Sections 39600, 39601, 39607, 39607.4, 41511, 38510, and 38530, Health and Safety Code. Reference: Sections 39600, 41511, and 38530, Health and Safety Code.

§ 95104. Emissions Data Report Contents and Mechanism.

The reporting entities specified in 95101 must develop, submit, and certify greenhouse gas emissions data reports to the Air Resources Board each year in accord with the following requirements.

(a) *General Contents.* In addition to the items specified at 40 CFR §98.3(c), each reporting entity must include in the emissions data report the following California information: ARB identification number, air basin, air district, county, and geographic location.

(b) *Designated Representative.* Each reporting entity must designate a reporting representative and adhere to the requirements for this representative at 40 CFR §98.4. Operators and suppliers with a reporting obligation under 40 CFR Part 98 must designate the same reporting representative as named under those requirements.

(c) *Corporate Parent and NAICS Codes.* Each reporting entity must submit information to meet the requirements specified in amendments to 40 CFR Part 98 on Reporting of Corporate Parent Information, NAICS Codes and Cogeneration, as promulgated by U.S. EPA on September 22, 2010.

(d) *Energy Purchases.* The operator must include in the emissions data report the facility's electricity purchases (kWh), and steam, heat, and cooling purchases (mmBtu), each by name and ARB identification number of the provider. The operator must report this information for the calendar year covered by the emissions data report, pro-rating purchases as necessary to include information for the full months of January and December.

(e) *Reporting Mechanism.* Reporting entities shall submit emissions data reports, and any revisions to the reports, through the California Air Resources Board's (ARB) Greenhouse Gas Reporting Tool, or any other reporting tool approved by the Executive Officer that will guarantee transmittal and receipt of data required by ARB's Mandatory Reporting Regulation and Cost of Implementation Fee Regulation.

NOTE: Authority cited: Sections 39600, 39601, 39607, 39607.4, 41511, 38510, and 38530, Health and Safety Code. Reference: Sections 39600, 41511, and 38530, Health and Safety Code.

§ 95105. Recordkeeping Requirements.

Each reporting entity that is required to report greenhouse gases under this article, except as provided in section 95103(c), must keep records as required by 40 CFR §98.3(g)-(h) with the following qualifications.

(a) *Duration.* Reporting entities with a compliance obligation under the Cap-and-Trade Regulation in any year of the current three-year compliance period must maintain all records specified in 40 CFR §98.3(g), and records associated with revisions to emissions data reports as provided under 40 CFR §98.3(h), for a period of ten years from the date of emissions data report certification. The retained documents, including GHG emissions data and input data, must be sufficient to allow for verification of each emissions data report. Reporting entities that do not have a compliance obligation under the Cap-and-Trade Regulation during any year of the current three-year compliance period must maintain such records for a period of five years from the date of certification.

(b) *ARB Requests for Records.* Copies of any records or other materials maintained under the requirements of 40 CFR Part 98 or this article must be made available to the Executive Officer upon request, within twenty days of receipt of such request by the designated representative of the reporting entity.

(c) *GHG Monitoring Plan.* Each reporting entity that reports under 40 CFR Part 98, and each reporting entity with a compliance obligation under the Cap-and-Trade Regulation in any year of the current three-year compliance period, must complete and retain for review by a verifier or ARB a written GHG Monitoring Plan that meets the requirements of 40 CFR §98.3(g)(5) and includes the following elements:

(1) All fuel use measurement devices used for emissions calculations must be clearly identified, and the plan must indicate how data from these devices are incorporated into the emissions data report;
2) Original equipment manufacturer (OEM) documentation, or other documentation that identifies instrument accuracy and required maintenance and calibration requirements for all measurement devices used in the calculation of GHG emissions.
(3) Training practices for personnel involved in GHG monitoring, including documented training procedures, and training materials;
(4) Copies of methodologies used for all fuel analyses.

NOTE: Authority cited: Sections 39600, 39601, 39607, 39607.4, 41511, 38510, and 38530, Health and Safety Code. Reference: Sections 39600, 41511, and 38530, Health and Safety Code.

§ 95106. Confidentiality.

(a) Emissions data submitted to the ARB under this article is public information and shall not be designated as confidential. Data reported to U.S. EPA under 40 CFR Part 98 which is determined to be non-confidential by U.S. EPA shall be considered public information by ARB.

(b) Any entity submitting information to the Executive Officer pursuant to this article may claim such information as "confidential" by clearly identifying such information as "confidential." Any claim of confidentiality by an entity submitting information must be based on the entity's belief that the information marked as confidential is either trade secret or otherwise exempt from public disclosure under the California Public Record Act (Government Code, section 6250 et seq.). All such requests for confidentiality shall be handled in accordance with the procedures specified in California Code of Regulations, title 17, sections 91000 to 91022.

NOTE: Authority cited: Sections 39600, 39601, 39607, 39607.4, 41511, 38510, and 38530, Health and Safety Code. Reference: Sections 39600, 41511, and 38530, Health and Safety Code.

§ 95107. Enforcement.

(a) Each day or portion thereof that any report required by this article remains unsubmitted, is submitted late, or contains information that is incomplete or inaccurate within the level of reproducibility of a test or measurement method is a separate violation. For purposes of this section, "report" means any emissions data report, verification statement, or other record required to be submitted to the Executive Officer by this article.

(b) Except as otherwise provided in this section, each day or portion thereof in which any other violation of this article occurs is a separate offense.

(c) Each metric ton of CO_2e emitted but not reported as required by this article is a separate violation.

(d) Each failure to measure, collect, record or preserve information needed for the calculation of emissions as required by this article or that this article otherwise requires be measured, collected, recorded or preserved constitutes a separate violation of this article.

(e) The Executive Officer may revoke or modify any Executive Order issued pursuant to this article as a sanction for a violation of this article.

(f) The violation of any condition of an Executive Order that is issued pursuant to this article is a separate violation.

(g) Penalties may be assessed for any violation of this article pursuant to Health and Safety Code section 38580.

(h) Any violation of this article may be enjoined pursuant to Health and Safety Code section 41513.

NOTE: Authority cited: Sections 39600, 39601, 39607, 39607.4, 41511, 38510, and 38530, Health and Safety Code. Reference: Sections 39600, 41511, and 38530, Health and Safety Code.

§ 95108. Severability.

Each part of this article shall be deemed severable, and in the event that any provision of this article is held to be invalid, the remainder of this article shall continue in full force and effect.

NOTE: Authority cited: Sections 39600, 39601, 39607, 39607.4, 41511, 38510, and 38530, Health and Safety Code. Reference: Sections 39600, 41511, and 38530, Health and Safety Code.

§ 95109. Standardized Methods.

(a) Entities that are required to report greenhouse gas emissions pursuant to this article must use either those standardized methods and materials listed in 40 CFR §98.7, or another similar method published by an organization listed in 40 CFR §98.7 that is applicable to the analysis being conducted. For gaseous fuels, fuel characteristics may be determined using chromatographic analysis as specified in 40 CFR §98.34(a)(6) and §98.34(b)(5). All methods used must be documented in the GHG Monitoring Plan that is as required by section 95105(c).

(b) Alternative test methods that are demonstrated to the satisfaction of the Executive Officer to be equally or more accurate than the methods in section 95109(a) may be used upon written approval by the Executive Officer.

NOTE: Authority cited: Sections 39600, 39601, 39607, 39607.4, 41511, 38510, and 38530, Health and Safety Code. Reference: Sections 39600, 41511, and 38530, Health and Safety Code.

Subarticle 2. Requirements for the Mandatory Reporting of Greenhouse Gas Emissions from Specific Types of Facilities, Suppliers, and Entities

§ 95110. Cement Production.

The operator of a facility who is required to report under section 95101 of this article, and who is not eligible for abbreviated reporting under section 95103(a), must comply with Subpart H of 40 CFR Part 98 (§§98.80 to 98.88) in reporting annual stationary combustion and process emissions from cement production to ARB, except as otherwise provided in this section.

(a) *CO_2 from Fossil Fuel Combustion.* When calculating CO_2 emissions from fuel combustion, the operator must use a method in 40 CFR §98.33(a)(1) to §98.33(a)(4) as specified by fuel type in section 95115 of this article.

(b) *Monitoring, Data and Records.* For each emissions calculation method chosen under section 95110(a), the operator must meet the applicable requirements for monitoring, missing data procedures, data reporting, and records retention that are specified in 40 CFR §98.34 to §98.37, except as modified in sections 95110(c), 95115, and 95129 of this article.

(c) *Missing Data Substitution Procedures.* The operator must comply with 40 CFR §98.85 when substituting for missing data, except as otherwise provided in paragraphs (1)-(3) below.

(1) To substitute for missing data for emissions reported under section 95115 of this article (stationary combustion units and units using continuous emissions monitoring systems), the operator must follow the requirements of section 95129 of this article.

(2) If data for the carbonate content of clinker or cement kiln dust as required by 40 CFR §98.83(d) are missing, and a new analysis cannot be undertaken, the operator must apply a substitute value according to the procedures in paragraphs (A)-(C) below.

(A) If the data capture rate is at least 90 percent for the data year, the operator must substitute each missing value using the best available estimate of the parameter, based on all available process data.

(B) If the data capture rate is at least 80 percent but not at least 90 percent for the data year, the operator must substitute each missing value with the highest quality assured value recorded for the parameter during the given data year, as well as the two previous data years.

(C) If the data capture rate is less than 80 percent for the data year, the operator must substitute each missing value with the highest quality assured value recorded for the parameter in all records kept according to section 95105(a).

(3) For each missing value of the monthly raw material consumption or monthly clinker production, the operator must apply a substitute value according to paragraphs (A)-(B) below.

(A) If the data capture rate is at least 80 percent for the data year, the operator must substitute each missing value according to 40 CFR §98.85(c) or 40 CFR §98.85(d), as applicable.

(B) If the data capture rate is less than 80 percent for the data year, the operator must substitute each missing value with the maximum tons of clinker per day capacity of the system or the maximum tons per day raw material throughput of the kiln, as applicable, and the number of days per month.

(4) The operator must document and retain records of the procedure used for all missing data estimates pursuant to the recordkeeping requirements of section 95105.

(d) *Additional Data to Support Benchmarking.* In addition to the information required by 40 CFR §98.86, the operator must report the additional parameters provided in paragraphs (1)-(2) below whether or not a CEMS is used to measure CO_2 emissions.

(1) Annual quantity of clinker substitute consumed for blending, by type (short tons).

(2) Annual quantity of cement substitute consumed, by type (short tons).

NOTE: Authority cited: Sections 39600, 39601, 39607, 39607.4, 41511, 38510, and 38530, Health and Safety Code. Reference: Sections 39600, 41511, and 38530, Health and Safety Code.

§ 95111. Data Requirements and Calculation Methods for Electric Power Entities.

Any electric power entity who is required to report under section 95101 of this article must comply with the following requirements when reporting to ARB.

(a) *General Requirements and Content for GHG Emissions Data Reports for Electricity Importers and Exporters.*

(1) *Greenhouse Gas Emissions.* The electric power entity must report GHG emissions separately for each category of delivered electricity required, in metric tons of CO_2 equivalent (CO_2e), according to the calculation methods in section 95111(b).

(2) *Delivered Electricity.* The electric power entity must report delivered electricity in MWh, and must also separately report all imported electricity from

unspecified sources by first point of receipt, and all imported electricity from each specified source.

(3) *Imported Electricity from Unspecified Sources.* When reporting imported electricity from unspecified sources, the electric power entity must aggregate electricity deliveries and associated GHG emissions by first point of receipt. The electric power entity also must report the following:

(A) The standardized acronym or code and the full name for the first point of receipt and the jurisdiction in which it is located;
(B) The amount of electricity from unspecified sources as measured at the first point of delivery in California; and,
(C) Whether transmission losses are made up in other electricity deliveries reported or from California sources. Transmission losses must be reported as required in section 95111(b).

(4) *Imported Electricity from Specified Facilities or Units.* When reporting imported electricity from specified facilities or units, the electric power entity must aggregate electricity deliveries and associated GHG emissions by facility or unit, as applicable.

(A) If the electric power entity holds a contract for a specified percentage of a facility's or unit's generation in the report year, the electric power entity must include electricity purchased or sold as being from a partially or fully owned facility or unit and meet the same requirements for partially or fully owned facilities or units in this section.
(B) Claims of specified sources of imported electricity must meet the requirements in section 95111(g) and include the following information:

1. Total facility or unit gross and net generation;
2. For specified deliveries from facilities or units that report GHG emissions to ARB or to U.S. EPA pursuant to 40 CFR Part 98, whether GHG emissions associated with net power generated exceed 1100 lbs CO_2e/MWh;
3. The amount of imported electricity from specified facilities or units as measured at the busbar; and
4. For imported electricity deliveries from specified facilities or units where measurements at the busbar are not known, the amount of imported electricity as measured at the first point of delivery in California and estimated transmission losses as required in section 95111(b). The electric power entity also must report whether transmission losses are made up in other imported electricity deliveries reported, or from California sources.

(5) *Imported Electricity from Asset-Controlling Suppliers.* The electric power entity must separately report imported electricity supplied by asset-controlling

suppliers recognized by ARB. Each asset-controlling supplier must be identified on the NERC E-tags as the PSE at the first point of receipt. The electric power entity must:

(A) Report the asset-controlling supplier standardized acronym or code, full name, and the ARB identification number;
(B) Report delivered electricity as specified and not as unspecified;
(C) Report delivered electricity from asset-controlling suppliers as measured at the first point of delivery in the state of California; and,
(D) Report GHG emissions calculated pursuant to section 95111(b).

(6) *Imported Electricity from Multi-jurisdictional Retail Providers.* The electric power entity must separately report imported electricity supplied by multi-jurisdictional retail providers who are recognized by the ARB as asset-controlling suppliers. Multi-jurisdictional retail providers are recognized by the ARB as asset-controlling suppliers when their system power emission factor, calculated and published on the ARB Mandatory Reporting website, is greater than 1100 lbs CO_2e/MWh.

(A) The electric power entity must report imported electricity supplied by multi-jurisdictional retail providers as measured at the first point of delivery in California.
(B) Multi-jurisdictional retail providers must report retail sales in their California service territory as imported electricity.
(C) The electric power entity must report GHG emissions calculated pursuant to section 95111(b). For multi-jurisdictional retail providers recognized by ARB as an asset-controlling suppliers, refer to subsection 95111(b)(3) and 95111(b)(4).

(7) *Exported Electricity.* The electric power entity must report exported electricity in MWh and associated GHG emissions in MT of CO_2e aggregated by each final point of delivery outside the state of California, as well as the following information:

(A) For each final point of delivery outside the state of California, include the standardized acronym or code, full name, and the jurisdiction in which it is located.
(B) Exported electricity as measured at the last point of delivery located in the state of California, if known. If unknown, report as measured at the final point of delivery outside California.
(C) Do not report estimated transmission losses.
(D) Report zero MT of CO_2e for each final point of delivery published on the ARB Mandatory Reporting website as located in a linked jurisdiction.
(E) For other final points of delivery, report associated emissions for each point by multiplying MWh exported by the emission factor calculated and

published on the ARB Mandatory Reporting website for unspecified imported electricity.

(8) *Exchange Agreements.* The electric power entity must report delivered electricity under power exchange agreements consistent with imported and exported electricity requirements of this section. Electricity delivered into the state of California under exchange agreements must be reported as imported electricity and electricity delivered out of California under exchange agreements must be reported as exported electricity.

(9) *Electricity Wheeled Through California.* The electric power entity must separately report electricity wheeled through California, aggregated by first point of receipt outside California, and must exclude wheeled power transactions from reported imports and exports. When reporting electricity wheeled through California, the power entity must include the quantities of electricity wheeled through California as measured at the first point of delivery inside the state of California.

(10) *Verification Documentation.* The electric power entity must retain for purposes of verification NERC E-tags, written contracts, settlements data, and all other information needed to confirm reported electricity procurements and deliveries pursuant to the recordkeeping requirements of section 95105.

(11) *Electricity Generating Units and Cogeneration in California.* Electric power entities that also operate electricity generating units or cogeneration located inside the state of California that meet the applicability requirements of this article must report GHG emissions to ARB under section 95112.

(12) *Electricity Generating Units and Cogeneration Outside California.* Operators and owners of electricity generating units and cogeneration located outside the state of California who elect to report to ARB under section 95112 must fully comply with the reporting and verification requirements of this article.

(b) Calculating GHG Emissions.

(1) *Calculating GHG Emissions from Unspecified Sources.* For electricity from unspecified sources, the electric power entity must calculate the annual CO_2 equivalent mass emissions using the following equation:

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

Where:

CO_2e = Annual CO_2 equivalent mass emissions from the unspecified electricity deliveries at each point of receipt identified (metric tons).

MWh = Megawatt-hours of unspecified electricity deliveries at each point of receipt identified.

EF_{unsp} = Default emission factor for unspecified electricity imports calculated and published on the ARB Mandatory Reporting website .

EF_{unsp} = 0.435 MT of CO_2e/MWh for first points of receipt located in non-linked jurisdictions.

EF_{unsp} = 0 MT of CO_2e/MWh for points of receipt located in linked jurisdictions.
TL = Transmission loss correction factor.
TL = 1.02 when transmission losses are not made up in other electricity deliveries reported or from California sources.
TL =1.0 when transmission losses are made up in other electricity deliveries reported or from California sources.

(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 (metric tons).
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. EF_{sp} = 0 MT of CO_2e for facilities located in linked jurisdictions and facilities, or units within facilities, below the GHG emissions compliance threshold for delivered electricity pursuant to the Cap-and-Trade Regulation
TL = Transmission loss correction factor.
TL = 1.02 when deliveries are not reported as measured at the busbar, and transmission losses are not made up in other electricity deliveries reported or from California sources.
TL = 1.0 when deliveries are reported as measured at the busbar, or transmission losses are made up in other electricity deliveries reported or from California sources.

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 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 from stationary combustion of fossil fuels, acid gas scrubbers, or acid gas reagents, as reported to ARB.

(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 equal to the sum of CO_2e emissions reported to U.S. EPA pursuant to 40 CFR Part 98.

(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.

$$E_{sp} = 0.001 \times \Sigma(Q_{fuel} \times EF_{fuel})$$

Where:

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

EF_{fuel} = CO_2e emission factor for the specified fuel type as required by this article (kg CO_2e /MMBtu).

(D) New facilities or units will be assigned an emission factor by the ARB based on the type of fuel combusted or the technology for the first year of reporting when a U.S. EPA GHG Report or EIA fuel consumption report is not available for the previous report year.

(3) *Calculating GHG Emissions of Imported Electricity from Specified Asset-Controlling Suppliers.* ARB will calculate and publish on the ARB Mandatory Reporting website system emission factors for the following asset-controlling suppliers: Bonneville Power Administration, multi-jurisdictional retail providers, and asset-controlling suppliers with a system emission factor greater than 1100 lbs CO_2e/MWh. For imported electricity from asset-controlling suppliers recognized by the ARB, the electric power entity must calculate emissions using the following equation:

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

Where:

CO_2e = Annual CO_2 equivalent mass emissions from the specified electricity deliveries from each supplier identified (metric tons).

MWh = Megawatt-hours of specified electricity deliveries.

EF_{ACS} = Supplier-specific emission factor published on the ARB Mandatory Reporting website (MT CO_2e/MWh). ARB will assign Bonneville Power Administration (BPA) a default system emission factor equal to 20 percent of the default emission factor for unspecified sources, or when available, based on a previously verified GHG report submitted to ARB, beginning in the 2010 data year and meeting the requirements for asset-controlling suppliers.

TL = Transmission loss correction factor.

TL = 1.02 when deliveries are not reported as measured at a first point of receipt located within the balancing authority area of the asset-controlling supplier and transmission losses are not made up in other electricity deliveries reported or from California sources.

TL = 1.0 when deliveries are reported as measured at a first point of receipt located within the balancing authority area of the asset-controlling supplier or transmission losses are made up in other electricity deliveries reported or from California sources.

The Executive Officer shall calculate the system emission factor for asset-controlling suppliers using the following equations:

EF_{ACS} = Sum of System Emissions MT of CO_2e / Sum of System MWh

Sum of System Emissions, MT of CO_2e = $\Sigma E_{asp} + \Sigma(PE_{sp} * EF_{sp}) + \Sigma(PE_{unsp} * EF_{unsp}) - \Sigma(SE_{sp} * EF_{sp})$

Sum of System MWh = $\Sigma EG_{asp} + \Sigma PE_{sp} + \Sigma PE_{unsp} - \Sigma SE_{sp}$

Where:

ΣE_{asp} = Sum of CO_2e emissions from each specified facility/unit in the asset-controlling supplier's fleet, consistent with section 95111(b)(2) (MT of CO_2e).

ΣEG_{asp} = Sum of net generation for each specified facility/unit in the asset-controlling supplier's fleet for the data year as reported to ARB under this article (MWh).

PE_{sp} = Amount of electricity purchased wholesale and taken from specified sources by the asset-controlling supplier for the data year as reported to ARB under this article (MWh).

PE_{unsp} = Amount of electricity purchased wholesale from unspecified sources by the asset-controlling supplier for the data year as reported to ARB under this article (MWh).

SE_{sp} = Amount of wholesale electricity sold from a specified source by the asset-controlling supplier for the data year as reported to ARB under this article (MWh).

EF_{sp} = CO_2e emission factor as defined for each specified facility or unit calculated consistent with section 95111(b)(2) (MT CO_2e/MWh).

EF_{unsp} = CO_2e default emission factor for unspecified sources calculated consistent with section 95111(b)(1) (MT CO_2e/MWh).

Multi-jurisdictional retail providers include emissions and megawatt-hours in the terms above from facilities or units that contribute to a common system power pool. Multi-jurisdictional retail providers do not include emissions or megawatt-hours in the terms above from facilities or units allocated to serve retail loads in designated states pursuant to a cost allocation methodology approved by the California Public Utilities Commission (CPUC) and the utility regulatory commission of at least one additional state in which the multi-jurisdictional retail provider provides retail electric service.

(4) *Calculating GHG Emissions of Imported Electricity from Multi-jurisdictional Retail Providers.* Multi-jurisdictional retail providers must calculate emissions using the following equation:

$$CO_2e = \left(MWh_R - MWh_{WSP-CA} - EG_{CA}\right) \times TL \times EF_{MJRP} + MWh_{WSP-notCA} \times TL \times EF_{MJRP} - CO_2e_{linked}$$

Where:

CO_2e = Annual CO_2e mass emissions of imported electricity (metric tons).

MWh_R = Total electricity procured by multi-jurisdictional retail provider to serve its retail customers in California, reported as retail sales for California service territory, MWh.

MWh_{WSP-CA} = Wholesale electricity procured in California by multi-jurisdictional retail provider to serve its retail customers in California, as determined by the first point of receipt on a NERC E-tag and pursuant to a cost allocation methodology approved by the California Public Utilities Commission (CPUC) and the utility regulatory commission of at least one additional state in which the multi-jurisdictional retail provider provides retail electric service, MWh.

$MWh_{WSP-not\ CA}$ = Wholesale electricity imported into California by multi-jurisdictional retail provider with a final point of delivery in California and not used to serve its California retail customers, MWh.

EF_{MJRP} = Multi-jurisdictional retail provider system emission factor calculated by ARB pursuant to subsection 95111(b)(3) and consistent with a cost allocation methodology approved by the California Public Utilities Commission (CPUC) and the utility regulatory commission of at least one additional state in which the multi-jurisdictional retail provider provides retail electric service.

EG_{CA} = net generation measured at the busbar of facilities and units located in California that are allocated to serve its retail customers in California pursuant to a cost allocation methodology approved by the California Public Utilities Commission (CPUC) and the utility regulatory

commission of at least one additional state in which the multi-jurisdictional retail provider provides retail electric service, MWh.
TL = Transmission loss correction factor.
TL = 1.02 when transmission losses are not made up in other electricity deliveries reported or from California sources.
TL = 1.0 when transmission losses are made up in other electricity deliveries reported or from California sources.

(c) *GHG Emissions Data Report: Additional Requirements for Retail Providers, excluding Multi-jurisdictional Retail Providers.* Retail providers must include the following information in the GHG emissions data report for each report year, in addition to the information identified in section 95111(a)-(b).

(1) Retail providers that serve California load must report California retail sales.
(2) Retail providers may elect to report the subset of retail sales attributed to the electrification of shipping ports, truck stops, and motor vehicles if metering is available to separately track these sales from other retail sales.
(3) Retail providers that serve California load must claim as specified electricity all electricity imported from facilities or units in which they have an ownership share or written contract to procure electricity.
(4) For facilities or units that are fully or partially owned by a retail provider that have GHG emissions greater than the default emission factor for unspecified imported electricity based on the most recent GHG emissions data report submitted to ARB or U.S. EPA, the retail provider must include:

(A) The facility name, ARB facility identification number and generating unit identification number as applicable, percent ownership share at the facility level, ownership share at the generating unit level as applicable, both net and gross nameplate capacity, and both net and gross power generated in the report year;
(B) The quantity of electricity sold by the retail provider or on behalf of the retail provider from the facility or unit having a final point of delivery outside California, as measured at the busbar.

(5) Retail providers that report as electricity importers also must separately report electricity imported from specified and unspecified sources by other electric power entities to serve their load, designating the electricity importer.

(d) *GHG Emissions Data Report: Additional Requirements for Multi-Jurisdictional Retail Providers.* Multi-jurisdictional retail providers that provide electricity into California at the distribution level must include the following information in the GHG emissions data report for each report year, in addition to the information identified in section 95111(a)-(b).

(1) A report of the electricity transactions and GHG emissions associated with the common power system or contiguous service territory that includes consumers

in California. This includes the requirements in this section as applicable for each generating facility or unit in the multi-jurisdictional retail provider's fleet;

(2) The multi-jurisdictional retail provider must include in its emissions data report wholesale power purchased and taken (MWh) from specified and unspecified sources and wholesale power sold from specified sources according to the specifications in this section, and as required for ARB to calculate a supplier-specific emission factor;

(3) Total retail sales (MWh) by the multi-jurisdictional retail provider in the contiguous service territory or power system that includes consumers in California;

(4) Retail sales (MWh) to California customers served in California's portion of the service territory;

(5) GHG emissions associated with the imported electricity, including both California retail sales and wholesale power imported into California from the retail provider's system, according to the specifications in this section;

(6) Multi-jurisdictional retail providers that serve California load must claim as specified power all power purchased or taken from facilities or units in which they have operational control or an ownership share or written contract;

(7) Multi-jurisdictional retail providers must provide the supplier-specific ARB identification number to electric power entities who purchase electricity from the supplier's system.

(e) *GHG Emissions Data Report:* Additional Requirements for WAPA and DWR.

(1) In reporting its GHG emissions to ARB, the California Department of Water Resources shall include all applicable information identified in this article for retail providers, including the amount of electricity used for pump loads, to operate the State Water Project.

(2) In reporting its GHG emissions to ARB, the Western Area Power Agency shall include all applicable information identified in this article for retail providers, including the amount of electricity used for pump loads, to operate the Central Valley Project.

(f) *GHG Emissions Data Report:* Additional Requirements for Asset-Controlling Suppliers. Bonneville Power Administration may request that ARB calculate its supplier-specific emission factor based on a previously verified GHG report that meets the requirements for asset-controlling suppliers, instead of a default system emission factor equal to 20 percent of the default emission factor for unspecified sources. An asset-controlling supplier that chooses this option must:

(1) Meet the requirements in this section as applicable for each generating facility or unit in the supplier's fleet;

(2) Include in its emissions data report wholesale power purchased and taken (MWh) from specified and unspecified sources and wholesale power sold from specified sources according to the specifications in this section, and as required for ARB to calculate a supplier-specific emission factor;

(3) Retain for verification purposes documentation that the power sold by the supplier originated from the supplier's fleet of facilities and either that the fleet is under the supplier's operational control or that the supplier serves as the fleet's exclusive marketer;
(4) Provide the supplier-specific ARB identification number to electric power entities who purchase electricity from the supplier's system.

(g) *Requirements for Claims of Specified Sources of Imported Electricity and Associated Emissions.* Electricity importers must register specified sources and report associated GHG emissions as follows:

(1) *Registration of Specified Sources and Suppliers.* Each electricity importer claiming specified sources or suppliers of electricity must register its specified sources and suppliers of electricity with ARB prior to January 1 of each reporting year. For purposes of registration under this paragraph, specified sources are facilities and units. Specified suppliers are asset-controlling suppliers and multi-jurisdictional retail providers. The electricity importer must include the following information when it registers its specified sources and suppliers:

(A) The facility names and, for specification to the unit level, provide the facility and unit names.
(B) For sources with a previously assigned ARB identification number, the ARB facility or unit identification number or supplier number published on ARB's mandatory reporting program website. For newly specified sources, ARB will assign a unique identification number.
(C) The facility and unit identification numbers as used for reporting to the Energy Information Administration, U.S. EPA Acid Rain Program, U.S. EPA pursuant to 40 CFR Part 98, and the California Energy Commission Eligible Renewable Resource identification number, as applicable.
(D) The physical address of each facility, including jurisdiction.
(E) The percent ownership share and whether the facility or unit is under the electricity importer's operational control.
(F) Total facility or unit gross and net nameplate capacity.
(G) Designate whether the facility emitted less than 25,000 metric tons of CO_2e as reported in the most recent GHG report to the ARB or to the U.S. EPA.
(H) Designate whether the facility or unit is a newly specified source, a continuing specified source, or was a specified source in the previous report year that will not be specified in the current report year.
(I) Provide the primary technology or fuel type as listed below:
1. Variable renewable resources by type, defined for purposes of this article as pure solar, pure wind, and run-of-river hydroelectricity;
2. Hybrid facilities such as solar thermal;
3. Hydroelectric facilities ≤ 30 MW, not run-of-river;
4. Hydroelectric > 30 MW;

5. Geothermal binary cycle plant or closed loop system;
6. Geothermal steam plant or open loop system;
7. Biomass-derived sources by primary fuel type;
8. Nuclear facilities;
9. Cogeneration by primary fuel type;
10. Fossil sources by primary fuel type;
11. Co-fired fuels;
12. Municipal solid waste combustion;
13. Other.

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

(3) *Owned Sources.* Electricity importers must report as specified sources of electricity the imported electricity from generating facilities or units located outside the state of California in which they have an ownership share, or written contract for a specified percentage of a facility's or unit's generation in the report year.

(4) *Delivery Tracking Conditions Required for Specified Electricity Imports.* Electricity importers may claim a specified source when the electricity delivery meets one of the following sets of conditions:

(A) The electricity importer has an ownership share in the facility or unit or a written contract for a specified percentage of the facility's or unit's generation in the report year;
(B) The electricity importer has a written contract to receive electricity generated by the facility or unit.

(5) *High GHG-Emitting Facilities or Units.* For facilities or units that are operated by a retail provider or fully or partially owned by a retail provider, excluding multi-jurisdictional retail providers, and that have emissions greater than the default emission factor for unspecified electricity based on the most recent GHG emissions data report submitted to ARB or to U.S.EPA, the retail provider must report the following information.

(A) When the product of net generation (MWh) and ownership share is greater than imported electricity (MWh), emissions transferred outside California must be reported as

$$CO_2e = (EG_{sp}*OS - I_{sp})*EF_{sp.}$$

Where:
EG_{sp} = facility or unit net generation, MWh.
OS = fraction ownership share.
I_{sp} = imported electricity, MWh.

$EF_{sp.}$ = facility or unit-specific emission factor, MT of CO_2e/MWh.

(B) List the replacement generation sources, locations, and whether they are new units when I_{sp}< 90% of EG_{sp}*OS and for a facility specified in the previous report year that has no imported electricity in the report year.

(6) *Low GHG-Emitting Existing, Fully Committed Resources: Nuclear and Large Hydroelectric Resources.* An emission factor of zero MT of CO_2e/MWh may only be used when electricity imported into California from a specified hydroelectric generating facility with nameplate capacity greater than 30 MW or a nuclear facility that was operational prior to January 1, 2010 meets one of the following conditions:

(A) Electricity purchased with a written contract in effect prior to January 1, 2010 that remains in effect or has been renegotiated for the same facility for the same share or quantity of net generation within one year of contract expiration;
(B) Electricity purchased that does not meet the first requirement that is associated with an increase in the facility's generating capacity due to increased efficiencies or other capacity increasing actions;
(C) Electricity purchased from hydroelectric generating facilities during a "spill or sell" situation where power not purchased is lost;
(D) Electricity purchased that does not meet the first requirement due to federal power redistribution policies for federally owned resources and not related to price bidding.

If none of the conditions in (A) through (D) above are met, apply the default emission factor for unspecified electricity pursuant to section 95111(b).

(7) *Substitute electricity.* Report substitute electricity received from specified and unspecified sources pursuant to the requirements of this section. Substitute electricity is provided under contract with specified facilities, not classified as variable renewable resources, to meet delivery requirements when the specified facility or unit is not operating.

NOTE: Authority cited: Sections 39600, 39601, 39607, 39607.4, 41511, 38510, and 38530, Health and Safety Code. Reference: Sections 39600, 41511, and 38530, Health and Safety Code.

§ 95112. Electricity Generation and Cogeneration Units.

The operator of a facility who is required to report under section 95101 of this article, and who is not eligible for abbreviated reporting under section 95103(a), must comply with Subparts C and D of 40 CFR Part 98 (§§98.30 to 98.48), as applicable, in reporting emissions from electricity generating and cogeneration units to ARB, except as otherwise provided in this section.

(a) *Basic Information for EGUs.* Notwithstanding any limitations in 40 CFR Parts 75 or 98, the operator of an electricity generating unit is required to include in the emissions data report the information listed in this paragraph. For aggregation of units that meet the applicable criteria in 40 CFR §98.36(c)(1)-(3), the operator may elect to report the following information for a group of aggregated units, in lieu of separately reporting for each single unit.

(1) Nameplate generating capacity in megawatts (MW);
(2) Net and gross power generated, in megawatt hours (MWh);
(3) Fuel consumption by fuel type, reporting in units of million standard cubic feet for gases, gallons for liquids, short tons for non-biomass solids, and bone dry short tons for biomass-derived solids;
(4) If not already required to be reported under 40 CFR §98.36(b)(6), annual CO_2, CH_4, and N_2O emissions from the unit, expressed in metric tons of each gas;
(5) If used to calculate CO_2 emissions and not already required to be reported under 40 CFR §98.36(b)(6), weighted average carbon content and high heat value by fuel type, determined using the same procedures as specified for HHV in 40 CFR §98.32(a)(2)(ii).
(6) For facilities whose primary sector is not electricity generation, report the following electricity generation information at the facility level, if known:
    (A) Electricity sold to the grid (MWh),
    (B) Electricity sold or provided directly to end-users (MWh), end-user's NAICS code and ARB ID (if an ARB ID has been assigned),
    (C) Electricity consumed on-site (MWh).

(b) *Basic Information for Cogeneration Units.* In addition to the information required by paragraph (a) of this section, the operator of a cogeneration unit must:

(1) Indicate whether the unit is topping or bottoming cycle, and the prime mover technology;
(2) Provide useful thermal output (mmBtu);
(3) Where steam or heat is acquired from another facility for the generation of electricity, report the provider, the provider's ARB ID, and the amount of acquired steam or heat (mmBtu);
(4) Where supplemental firing has been applied to support electricity generation or industrial output, report fuel consumption by fuel type using the units in paragraph (a)(3) of this section and indicate the purpose of the supplemental firing.

(c) *CO_2 from Fossil Fuel Combustion.* When calculating CO_2 emissions from fuel combustion, the operator who is subject to Subpart C or D of 40 CFR Part 98 must use a method in 40 CFR §98.33(a)(1) to §98.33(a)(4) as specified by fuel type in section 95115 of this article.

(d) *Monitoring, Data and Records.* For each emissions calculation method chosen under section 95112(c), the operator must meet the applicable requirements for monitoring, missing data procedures, data reporting, and records retention that are specified in 40 CFR §98.34 to §98.37, except as modified in sections 95112, 95115, and 95129 of this article.

(e) *Biomass Emissions for Units Reporting Under 40 CFR Part 75.* Operators of electricity generating and cogeneration units subject to 40 CFR Part 75 and the data reporting requirements in 40 CFR §98.36(d) that combust both fossil and biomass-derived fuels must separately report CO_2 emissions from combustion of fossil fuels and CO_2 emissions from the combustion of biomass-derived fuels. The biogenic portion of CO_2 emissions must be calculated according to the methodology specified in 40 CFR §98.33(e).

(f) *CO_2 and CH_4 Emissions from Geothermal Facilities.* Operators of geothermal generating facilities must calculate annual emissions of CO_2 and CH_4 from geothermal energy sources using source specific emission factors derived from a measurement plan approved by the ARB. The operator must submit to the Executive Officer a measurement plan at least 45 days prior to the first test date. The measurement plan must include testing at least annually, and more frequently as needed. Upon approval of the measurement plan by the Executive Officer, the test procedures in that plan must be performed as specified in the plan. The Executive Officer and the local air pollution control officer must be notified at least 20 days in advance of subsequent tests.

(g) *Hydrogen Fuel Cells.* Operators of stationary hydrogen fuel cell units that produce hydrogen on-site must report information on the feedstocks used in hydrogen production. The operator must include the following information in the annual GHG emissions data report:

(1) Nameplate generating capacity in megawatts (MW);
(2) Net and gross power generated, in megawatt hours (MWh);
(3) Fuel or feedstock consumption by fuel/feedstock type, reporting in units of million standard cubic feet for gases, gallons for liquids, short tons for non-biomass solids, and bone dry short tons for biomass-derived solids;
(4) The provider of each fuel or feedstock, and the user's customer account number;
(5) Cogeneration information in section 95112(b), if applicable.

(h) *Missing Data Substitution Procedures.* To substitute for missing data for emissions reported under sections 95112 or 95115 of this article (stationary combustion units and units using continuous emissions monitoring systems), the operator must follow the requirements of section 95129 of this article. Facilities reporting under 40 CFR Part 75 must substitute for missing data under the requirements of that part, as specified in 40 CFR §98.45.

NOTE: Authority cited: Sections 39600, 39601, 39607, 39607.4, 41511, 38510, and 38530, Health and Safety Code. Reference: Sections 39600, 41511, and 38530, Health and Safety Code.

§ 95113. Petroleum Refineries.

The operator of a facility who is required to report under section 95101 of this article, and who is not eligible for abbreviated reporting under section 95103(a), must comply with Subpart Y of 40 CFR Part 98 (40 CFR §§98.250 to 98.258) in reporting annual emissions from petroleum refineries to ARB, except as otherwise provided in this section.

(a) *CO_2 from Fossil Fuel Combustion.* When calculating CO_2 emissions from fuel combustion under subpart C as specified at 40 CFR §98.252(a), the operator must use a method in 40 CFR §98.33(a)(1) to §98.33(a)(4) as specified by fuel type in section 95115 of this article. CO_2 emissions from refinery fuel gas combustion must be calculated using a Tier 3 or Tier 4 methodology of subpart C, as specified in 40 CFR §98.252(a).

(b) *Monitoring, Data and Records.* For each emissions calculation method chosen under section 95113(a), the operator must meet the applicable requirements for monitoring, missing data procedures, data reporting, and records retention that are specified in 40 CFR §98.34 to §98.37, except as modified in sections 95113(l), 95115, and 95129 of this article.

(c) *Refinery Fuel Gas Sampling.* As required by 40 CFR §98.34(b)(3)(ii)(E), in cases where equipment necessary to perform daily sampling and analysis of carbon content and molecular weight for refinery fuel gas is not in place, such equipment must be installed and procedures established to implement daily sampling and analysis no later than January 1, 2013.

(d) *Calculating CO_2 from Flares.* For periods of normal flare operation, the operator must use Equation Y-1 or Equation Y-2 as specified in 40 CFR §98.253(b)(ii)(A) or 98.253(b)(ii)(B). For periods of startup, shutdown, and malfunction (SSM) during which the operator was unable to measure the parameters required by Equations Y-1 and Y-2, the operator must determine the quantity of gas discharged to the flare separately for each SSM, and calculate the CO_2 emissions as specified in the equation shown below. For SSM periods the operator must use engineering calculations and process knowledge to estimate the carbon content of flared gas as required by §98.253(b)(iii)(A). The terms of the equation below are defined as they are for Equation Y-3 in 40 CFR §98.253(b)(iii)(C).

$$CO_2 = 0.98 \times 0.001 \times \left(\sum_{p=1}^{n} \left[44/12 \times (Flare_{SSM})_p \right] \times MW_p / MVC \times CC_p \right)$$

(e) *Calculating CO_2 from FCCUs and Fluid Coking.* The requirements of 40 CFR §98.253(c)(2) apply under this article regardless of the rated capacity of a fluid catalytic cracking unit or a fluid coking unit. The operator may not use Equation Y-8 or the option provided under 40 CFR §98.253(c)(3) for units with rated capacities of 10,000 barrels per stream day or less.

(f) *Calculating CH_4 from Delayed Coking Units.* When calculating CH_4 emissions from the depressurization of the coking unit vessel as required by 40 CFR §98.253(i), the operator must conduct the sampling and engineering analysis necessary to apply the two terms below, from Equation Y-18, modified as follows:

f_{void} = Volumetric void fraction of coking vessel prior to steaming based on engineering calculations (cf gas/cf of vessel).

MF_{CH4} = Average mole fraction of methane in coking vessel gas based on the analysis of at least two samples per year, collected at least four months apart (kg-mole CH_4/kg-mole gas, wet basis).

(g) *Uncontrolled Blowdown Systems.* When calculating CH_4 emissions for uncontrolled blowdown systems as required by 40 CFR §98.253(k), the operator must use the methods for process vents in 40 CFR §98.253(j).

(h) *Data Reporting Requirements for Flares.* When the operator has calculated flare emissions for SSM periods using the modified equation specified in section 95113(d), the operator reporting data under the requirements of 40 CFR §98.256(e)(8) must report only the total number of SSM events, the volume of gas flared, and the average molecular weight and carbon content of the flare gas for each SSM event, using the units specified.

(i) *Data Reporting Requirements for FCCUs and Coking Units.* When the operator has calculated CO_2 from fluid catalytic cracking units or fluid coking units consistent with section 95113(e), the operator shall not report the data required by 40 CFR §98.256(f)(9).

(j) *Data Reporting Requirements for Uncontrolled Blowdown Systems.* When the operator has calculated CH_4 from uncontrolled blowdown systems consistent with section 95113(g), the operator must report the information required for process vents in 40 CFR §98.256(l), as applicable, in lieu of the information required by 40 CFR §98.256(m)(2).

(k) *Records that must be retained.* In addition to the requirements of 40 CFR §98.257, for each process vent for which the concentration of CO_2, N_2O and CH_4 are determined to be below the thresholds in 40 CFR §98.253(j), the operator must maintain records of the method used to determine the CO_2, N_2O, and CH_4 concentrations, and all supporting documentation necessary to demonstrate that the thresholds in 40 CFR §98.253(j) are not exceeded during the data year pursuant to the record keeping requirements of section 95105.

(l) *Missing Data Substitution Procedures.* The operator must comply with 40 CFR §98.255 when substituting for missing data, except as otherwise provided in paragraphs (1)-(2) below.

(1) To substitute for missing data for emissions reported under section 95115 of this article (stationary combustion units and units using continuous emissions monitoring systems), the operator must follow the requirements of section 95129 of this article.

(2) For all other data required for emissions calculations in this section, the operator must follow the requirements of paragraphs (A)-(B) below.

(A) If the analytical data capture rate is at least 90 percent for the data year, the operator must substitute each missing value using the best available estimate of the parameter, based on all available process data.

(B) If the analytical data capture rate is at least 80 percent but not at least 90 percent for the data year, the operator must substitute each missing value with the highest quality assured value recorded for the parameter during the given data year, as well as the two previous data years.

(C) If the analytical data capture rate is less than 80 percent for the data year, the operator must substitute each missing value with the highest quality assured value recorded for the parameter in all records kept according to section 95105(a).

(m) *Additional Data Reporting Requirements for Benchmarking Purposes.* The operator must report production quantities for the data year of each petroleum product listed in Table C-1 of 40 CFR Part 98, and each additional transportation fuel product listed in Table MM-1 of 40 CFR Part 98 (standard cubic feet for gaseous products, gallons for liquid products, short tons for solid products).

NOTE: Authority cited: Sections 39600, 39601, 39607, 39607.4, 41511, 38510, and 38530, Health and Safety Code. Reference: Sections 39600, 41511, and 38530, Health and Safety Code.

§ 95114. Hydrogen Plants.

The operator of a facility who is required to report under section 95101 of this article, and who is not eligible for abbreviated reporting under section 95103(a), must comply with Subpart P of 40 CFR Part 98 (40 CFR §§98.160 to 98.168) in reporting annual emissions from hydrogen production to ARB, except as otherwise provided in this section.

(a) *Definition of Source Category.* This source category includes merchant hydrogen production facilities located within another facility if they are not owned by, or under the direct control of, the other facility's owner or operator.

(b) *CO_2 from Fossil Fuel Combustion.* When calculating CO_2 emissions from fuel combustion under subpart C as specified at 40 CFR §98.162(b)-(c), the operator must use a method in 40 CFR §98.33(a)(1) to §98.33(a)(4) as specified by fuel type in section 95115 of this article.

(c) *Monitoring, Data and Records.* For each emissions calculation method chosen under section 95114(b), the operator must meet the applicable requirements for monitoring, missing data procedures, data reporting, and records retention that are specified in 40 CFR §98.34 to §98.37, except as modified in sections 95114(h), 95115, and 95129 of this article.

(d) *CO_2 Process Emissions.* When calculating CO_2 under the fuel and feedstock material balance approach specified at 40 CFR §98.163(b), the operator must apply the weighted average carbon content values obtained (the term CC_n in Equations P-1 through P-3) according to the frequencies specified in section 95114(e).

(e) *Sampling Frequencies.* When monitoring GHG emissions without a CEMS as specified at 40 CFR §98.164(b)(2), and reporting data as specified at §98.166, the operator must determine the carbon content and molecular weight values for fuels and feedstocks according to the frequencies specified below.

(1) When reporting CO_2 emissions for gaseous fuel and feedstock as specified in 40 CFR §98.163(b)(1), the operator must use a weighted average carbon content from the results of one or more analyses for month n for natural gas, or from daily analysis for gaseous fuels and feedstocks other than natural gas;
(2) When reporting CO_2 emissions for liquid fuel and feedstock as specified in 40 CFR §98.163(b)(2), the operator must use weighted average carbon content from the results of daily sampling for month n. Daily liquid samples may be combined to generate a monthly composite sample for carbon analysis;
(3) When reporting CO_2 emissions for solid fuel and feedstock as specified in 40 CFR §98.163(b)(3), the operator must use weighted average carbon content from the results of daily sampling for month n. Daily solid samples may be combined to generate a monthly composite sample for carbon analysis.

(f) *Weighted Average Sampling.* Where this section requires sampling of a parameter on a more frequent basis than 40 CFR Part 98, the operator or supplier must comply with the following:

(1) The samples must be spaced apart as evenly as possible over time, taking into account the operating schedule of the relevant unit or facility.
(2) The operator or supplier must calculate and report a weighted average of the values derived from the samples by using the following formula:

$$V_E = \frac{\sum_{j=1}^{n}(V_j \times M_j)}{\sum_{j=1}^{n} M_j}$$

Where:

V_E = The value of the parameter to be reported under 40 C.F.R. Part 98 for period E.

j = Each period during period E for which a sample is required by this article.

n = The number of periods j in period E.

V_j = The value of the sample for period j.

M_j = The mass of the sampled material processed or otherwise used by the relevant unit or facility in period j.

(3) The operator or supplier must keep records of the date and result for each sample or composite sample and mass measurement used in the equation above and of the calculation of each weighted average included in the emissions data report, pursuant to the record keeping requirements of section 95105.

(g) *Data Reporting Requirements.* When reporting data as specified at §98.166, the operator must also report the amount of carbon in unconverted feedstock for which GHG emissions are calculated and reported by the facility using other calculation methods provided in this regulation. For example, carbon in waste diverted to a fuel system or flare, where the CO_2 and CH_4 emissions are calculated and reported using other methods provided in this regulation, should be separately specified (metric tons of CO_2e/year). The operator must also report the amount of hydrogen produced and sold as a transportation fuel, if known.

(h) *Missing Data Substitution Procedures.* The operator must comply with 40 CFR §98.165 when substituting for missing data, except as otherwise provided in paragraphs (1)-(2) below.

(1) To substitute for missing data for emissions reported under section 95115 of this article (stationary combustion units and units using continuous emissions monitoring systems), the operator must follow the requirements of section 95129 of this article.

(2) For all other data required for emissions calculations in this section, the operator must follow the requirements of paragraphs (A)-(C) below.

(A) If the analytical data capture rate is at least 90 percent for the data year, the operator must substitute each missing value using the best available estimate of the parameter, based on all available process data.

(B) If the analytical data capture rate is at least 80 percent but not at least 90 percent for the data year, the operator must substitute each missing value with the highest quality assured value recorded for the parameter during the given data year, as well as the two previous data years.

(C) If the analytical data capture rate is less than 80 percent for the data year, the operator must substitute each missing value with the highest quality

assured value recorded for the parameter in all records kept according to section 95105(a).

NOTE: Authority cited: Sections 39600, 39601, 39607, 39607.4, 41511, 38510, and 38530, Health and Safety Code. Reference: Sections 39600, 41511, and 38530, Health and Safety Code.

§ 95115. Stationary Fuel Combustion Sources.

The operator of a facility who is required to report under section 95101 of this article, and who is not eligible for abbreviated reporting under section 95103(a), must comply with Subpart C of 40 CFR Part 98 (§§98.30 to 98.38) in reporting annual stationary fuel combustion emissions to ARB, except as otherwise provided in this section.

(a) *CO_2 from Steam Producing Units.* The operator of a steam producing unit combusting municipal solid waste or solid biomass fuels may use Equation C-2c of 40 CFR §98.33(a)(2)(B)(iii). Operators of units combusting fossil-based solid fuels must select applicable Tier 3 or Tier 4 methods.

(b) *CEMS CO_2 Monitoring.* Notwithstanding the allowance of oxygen concentration monitors in 40 CFR 98.33(a)(4)(iv), an operator installing a continuous emissions monitoring system that includes a stack gas volumetric flow rate monitor after January 1, 2012 must install and use a CO_2 monitor to report CO_2 emissions. An operator without a CO_2 monitor who uses a CEMS and O_2 concentrations to calculate and report a unit's CO_2 emissions, and who conducts a Relative Accuracy Test Audit (RATA) for the unit, must at least annually include in the RATA the direct monitoring of CO_2 concentration and flow, and the calculation of CO_2 mass per hour. The operator must retain these results pursuant to the recordkeeping requirements of section 95105 and make them available to ARB upon request. The requirements of this paragraph do not apply to facilities for which pipeline natural gas is the only fuel consumed.

(c) *Choice of Tier for Calculating CO_2 Emissions.* Notwithstanding the provisions of 40 CFR §98.33(b), the operator's selection of a method for calculation of CO_2 emissions from combustion sources is subject to the following limitations by fuel type and unit size. The operator is permitted to select a higher tier than that required for the fuel type or unit size as specified below.

(1) The operator may select the Tier 1 or Tier 2 calculation method specified in 40 CFR §98.33(a) for any fuel listed in Table 1 of this section that is combusted in a unit with a maximum rated heat input capacity of 250 mmBtu/hr or less, subject to the limitation at 40 CFR §98.33(b)(1)(iv), or for biomass-derived fuels not subject to a compliance obligation under the Cap-and-Trade Regulation, when listed in Table C-1 of 40 CFR Part 98.

(2) The operator may select the Tier 2 calculation method specified in 40 CFR §98.33(a)(2) for natural gas when it is pipeline quality as defined in section

95102 of this article, and for distillate fuels listed in Table 1 of this section. Equation C-2c may be selected for the units specified in paragraph (a) of this section.

(3) The operator may select any calculation method specified in 40 CFR §98.33(a) when calculating emissions that are shown to be *de minimis* under section 95103(i)of this article, or for a fuel providing less than 10 percent of the annual heat input to a unit with a maximum rated heat input capacity of 250 mmBtu/hr or less, unless not permitted under 40 CFR §98.33(b).

(4) The operator must use either the Tier 3 or the Tier 4 calculation method specified under 40 CFR §98.33(a)(3)-(4) for any other fuel, subject to the limitations of 40 CFR §98.33(b)(4)-(5) requiring use of the Tier 4 method.

(d) *Source Test Option for N_2O and CH_4.* In lieu of other methods specified in this article, a facility operator may conduct site-specific source testing to derive emission factors and determine annual emissions of N_2O or CH_4 from any combustion source. Alternatively, the operator may use the results of an applicable test method specified in title 17, California Code of Regulations, section 95471. For source testing:

(1) The facility operator must submit to the Executive Officer a test plan at least 45 days prior to the first test date. The test plan must provide for testing at least annually, and more frequently as needed to account for seasonal variations in fuels or processes.

(2) The plan must specify conduct of performance and stack tests consistent with the requirements of approved ARB or U.S. EPA test methods. Process rates during the test must be determined in a manner that is consistent with the procedures used for GHG report accounting purposes.

(3) Upon approval of the test plan by the Executive Officer, the test procedures in that plan must be repeated as specified in the plan. The Executive Officer and the local air pollution control officer must be notified at least ten days in advance of subsequent tests.

(e) *Procedures for Biomass CO_2 Determination.* When combusting MSW or any other fuel for which the biomass fraction is not known, the operator must follow the procedures specified in 40 CFR §98.33(e)(3) to specify a biomass fraction.

(f) *Fuel Sampling Frequencies.* The operator who collects and analyzes fuel samples to conduct the monitoring analyses required under 40 CFR §98.34 must sample at the frequencies specified in that section, except in the following cases.

(1) Natural gas that is outside the range of pipeline quality as defined in section 95102 must be sampled and analyzed at least monthly by the reporting entity or the fuel supplier.

(2) Under 40 CFR §98.34(b)(3)(ii)(E), in cases where equipment necessary to perform daily sampling and analysis of carbon content and molecular weight

for refinery fuel gas is not in place, such equipment must be installed and procedures established to implement daily sampling and analysis no later than January 1, 2013.

(g) *Electricity Generating and Cogeneration Units.* The operator of a facility that includes electricity generating and cogeneration units meeting the applicability criteria of section 95101 must meet the requirements specified in section 95112 of this article.

(h) *Natural Gas Provider.* The operator must report the provider(s) of natural gas to the facility, and the operator's customer account number(s).

(i) *Procedures for Missing Data.* To substitute for missing data for emissions reported under section 95115 of this article, the operator must follow the requirements of section 95129.

(j) *Additional Data to Support Benchmarking.* Operators of the following types of facilities must also report the production quantities indicated below.

(1) The operator of a facility engaged in the production and manufacture of hot rolled sheet steel, galvanized sheet steel, or both, must report the quantity of hot rolled sheet steel and galvanized sheet steel produced in the data year (short tons).
(2) The operator of a soda ash manufacturing facility must report the quantity of soda ash produced in the data year (short tons).
(3) The operator of a gypsum manufacturing facility must report quantities produced of each of the following products (short tons): dry gypsum; plaster; gypsum blocks, plasterboards and coving; and glass-fiber reinforced gypsum (GRG) plasterboards.

Table 1: Petroleum Fuels For Which Tier 1 or Tier 2 Calculation Methodologies May Be Used Under Section 95115(c)(1)

Fuel Type	*Default High Heat Value*	*Default CO_2 Emission Factor*
	mmBtu/gallon	*kg CO_2 /mmBtu*
Distillate Fuel Oil No. 1	0.139	73.25
Distillate Fuel Oil No. 2	0.138	73.96
Distillate Fuel Oil No. 4	0.146	75.04
Kerosene	0.135	75.20
Liquefied petroleum gases (LPG)[1]	0.092	62.98
Propane	0.091	61.46
Propylene	0.091	65.95
Ethane	0.096	62.64
Ethylene	0.100	67.43
Isobutane	0.097	64.91
Isobutylene	0.103	67.74
Butane	0.101	65.15

[1] Commercially sold as "propane," including grades such as HD5.

Table 1: Petroleum Fuels For Which Tier 1 or Tier 2 Calculation Methodologies May Be Used Under Section 95115(c)(1)

Fuel Type	*Default High Heat Value*	*Default CO_2 Emission Factor*
Butylene	0.103	67.73
Natural Gasoline	0.110	66.83
Motor Gasoline	0.125	70.22
Aviation Gasoline	0.120	69.25
Kerosene-Type Jet Fuel	0.135	72.22

NOTE: Authority cited: Sections 39600, 39601, 39607, 39607.4, 41511, 38510, and 38530, Health and Safety Code. Reference: Sections 39600, 41511, and 38530, Health and Safety Code.

§ 95116. Glass Production.

The operator of a facility who is required to report under section 95101 of this article, and who is not eligible for abbreviated reporting under section 95103(a), must comply with Subpart N of 40 CFR Part 98 (§§98.140 to 98.148) in reporting annual stationary combustion and process emissions from glass production to ARB, except as otherwise provided in this section.

(a) *CO_2 from Fossil Fuel Combustion.* When calculating CO_2 emissions from fuel combustion, the operator must use a method in 40 CFR §98.33(a)(1) to §98.33(a)(4) as specified by fuel type in section 95115 of this article.

(b) *Monitoring, Data and Records.* For each emissions calculation method chosen under section 95116(a), the operator must meet the applicable requirements for monitoring, missing data procedures, data reporting, and records retention that are specified in 40 CFR §98.34 to §98.37, except as modified in sections 95115, 95116(c), and 95129 of this article.

(c) *Missing Data Substitution Procedures.* The operator must comply with 40 CFR §98.145 when estimating missing data, except as otherwise provided in paragraphs (1)-(3) below.

(1) To substitute for missing data for emissions reported under section 95115 of this article (stationary combustion units and units using continuous emissions monitoring systems), the operator must follow the requirements of section 95129 of this article.

(2) For each missing value of the monthly amounts of carbonate-based raw materials charged to any continuous glass melting furnace, the operator must apply a substitute value according to the procedures in paragraphs (A)-(B) below.

(A) If the data capture rate is at least 80 percent for the data year, the operator must substitute each missing value according to 40 CFR §98.145(a).
(B) If the data capture rate is less than 80 percent for the data year, the operator must substitute each missing value with the maximum tons per day raw material capacity of the continuous glass melting furnace.

(3) The operator must document and retain records of the procedure used for all missing data estimates pursuant to the recordkeeping requirements of section 95105.

(d) *Additional Data to Support Benchmarking.* In addition to the information required by 40 CFR §98.146, the operator must report the additional parameters provided in paragraphs (1)-(2) below whether or not a CEMS is used to measure CO_2 emissions.

(1) Annual quantity of packed or sellable glass produced (short tons).
(2) Annual quantity of fiberglass produced (short tons).

NOTE: Authority cited: Sections 39600, 39601, 39607, 39607.4, 41511, 38510, and 38530, Health and Safety Code. Reference: Sections 39600, 41511, and 38530, Health and Safety Code.

§ 95117. Lime Manufacturing.

The operator of a facility who is required to report under section 95101 of this article, and who is not eligible for abbreviated reporting under section 95103(a), must comply with Subpart S of 40 CFR Part 98 (§§98.190 to 98.198) in reporting annual stationary combustion and process emissions from lime manufacturing to ARB, except as otherwise provided in this section.

(a) *CO_2 from Fossil Fuel Combustion.* When calculating CO_2 emissions from fuel combustion, the operator must use a method in 40 CFR §98.33(a)(1) to §98.33(a)(4), as specified by fuel type in section 95115 of this article.

(b) *Monitoring, Data and Records.* For each emissions calculation method chosen under section 95117(a), the operator must meet the applicable requirements for monitoring, missing data procedures, data reporting, and records retention that are specified in 40 CFR §98.34 to §98.37, except as modified in sections 95115, 95117(c), and 95129 of this article.

(c) *Missing Data Substitution Procedures.* The operator must comply with 40 CFR §98.195 when substituting for missing data, except as otherwise provided in paragraphs (1)-(2) below.

(1) To substitute for missing data for emissions reported under section 95115 of this article (stationary combustion units and units using continuous emissions monitoring systems), the operator must follow the requirements of section 95129 of this article.

(2) If CaO and MgO content data required by 40 CFR §98.193(b)(2) are missing and a new analysis cannot be undertaken, the operator must apply substitute values according to the procedures in paragraphs (A)-(C) below.

(A) If the data capture rate is at least 90 percent for the data year, the operator must substitute each missing value using the best available estimate of the parameter, based on all available process data.

(B) If the data capture rate is at least 80 percent but not at least 90 percent for the data year, the operator must substitute each missing value with the highest quality assured value recorded for the parameter during the given data year, as well as the two previous data years.

(C) If the data capture rate is less than 80 percent for the data year, the operator must substitute each missing value with the highest quality assured value recorded for the parameter in all records kept according to section 95105(a).

(3) For each missing value of the quantity of lime produced (by lime type) and quantity of lime byproduct/waste produced and sold, the operator must apply a substitute value according to the procedures in paragraphs (A)-(B) below.

(A) If the data capture rate is at least 80 percent for the data year, the operator must substitute each missing value according to 40 CFR §98.195(a).

(B) If the data capture rate is less than 80 percent for the data year, the operator must substitute each missing value with the maximum capacity of the system.

(4) The operator must document and retain records of the procedure used for all missing data estimates pursuant to the recordkeeping requirements of section 95105.

NOTE: Authority cited: Sections 39600, 39601, 39607, 39607.4, 41511, 38510, and 38530, Health and Safety Code. Reference: Sections 39600, 41511, and 38530, Health and Safety Code.

§ 95118. Nitric Acid Production.

The operator of a facility who is required to report under section 95101 of this article, and who is not eligible for abbreviated reporting under section 95103(a), must comply with Subpart V of 40 CFR Part 98 (§§98.220 to 98.228) in reporting annual stationary combustion and process emissions from nitric acid production to ARB, except as otherwise provided in this section.

(a) *CO_2 from Fossil Fuel Combustion.* When calculating CO_2 emissions from fossil fuel combustion at a stationary combustion unit under 40 CFR §98.222(b), the operator must use a method in 40 CFR §98.33(a)(2) to §98.33(a)(4) as specified by fuel type in section 95115 of this article.

(b) *Monitoring, Data and Records.* For each emissions calculation method chosen under section 95118(a), the operator must meet the applicable requirements for monitoring, missing data procedures, data reporting, and records retention that are specified 40 CFR §98.34 to §98.37, except as modified in sections 95115, 95118(d), and 95129 of this article.

(c) *Missing Data Substitution Procedures.* The operator must comply with 40 CFR §98.225 when substituting for missing data, except as otherwise provided in paragraphs (1)-(3) below.

(1) To substitute for missing data for emissions reported under section 95115 of this article (stationary combustion units and units using continuous emissions monitoring systems), the operator must follow the requirements of section 95129 of this article.

(2) For each missing value of nitric acid production, the operator must substitute the missing data values according to the procedures in paragraphs (A)-(B) below.

(A) If the analytical data capture rate is at least 80 percent for the data year, the operator must substitute each missing value according to 40 CFR §98.225(a) and the number of days per month.

(B) If the analytical data capture rate is less than 80 percent for the data year, the operator must substitute each missing value with the maximum capacity of the system and the number of days per month.

(3) The operator must document and keep records of the procedures used for estimating missing data pursuant to the recordkeeping requirements of section 95105.

NOTE: Authority cited: Sections 39600, 39601, 39607, 39607.4, 41511, 38510, and 38530, Health and Safety Code. Reference: Sections 39600, 41511, and 38530, Health and Safety Code.

§ 95119. Pulp and Paper Manufacturing

The operator of a facility who is required to report under section 95101 of this article, and who is not eligible for abbreviated reporting under section 95103(a), must comply with Subpart AA of 40 CFR Part 98 (40 CFR §§98.270 to 98.278) in reporting annual stationary combustion and process emissions from pulp and paper manufacturing to ARB, except as otherwise provided in this section.

(a) *CO_2 from Fossil Fuel Combustion.* When calculating CO_2 emissions from fossil fuel combustion in a chemical recovery furnace at a kraft or soda facility under 40 CFR §98.273(a)(1), a chemical recovery unit at a sulfite or stand-alone semichemical facility under 40 CFR §98.273(b)(1), a pulp mill lime kiln at a kraft or soda facility under 40 CFR §98.273(c)(1), or other stationary fuel combustion sources, the operator must use a method in 40 CFR §98.33(a)(1) to §98.33(a)(4) as specified by fuel type in section 95115 of this article.

(b) *Monitoring, Data and Records.* For each emissions calculation method chosen under section 95119(a), the operator must meet the applicable requirements for monitoring, missing data procedures, data reporting, and records retention that are specified in 40 CFR §98.34 to §98.37, except as modified in sections 95115, 95119(c), and 95129 of this article.

(c) *Procedures for Missing Data.* The operator must comply with 40 CFR §98.275 when substituting for missing data, except as otherwise provided in paragraphs (1)-(3) below.

(1) To substitute for missing data for emissions reported under section 95115 of this article (stationary combustion units and units using continuous emissions monitoring systems), the operator must follow the requirements of section 95129 of this article.

(2) For each missing value for the use of makeup chemicals (carbonates), the operator must apply a substitute value according to the procedures in paragraphs (A)-(B) below.

(A) If the data capture rate is at least 80 percent for the data year, the operator must substitute each missing value according to 40 CFR §98.275(c).

(B) If the data capture rate is less than 80 percent for the data year, the operator must substitute each missing value with the maximum metric tons per day capacity of the system.

(3) The operator must document and retain records of the procedure used for all missing data estimates pursuant to the recordkeeping requirements of section 95105.

(d) *Additional Data to Support Benchmarking.* In addition to the information required by 40 CFR §§98.276, the operator must report the annual production (short tons) of each of the following: pulp purchased or manufactured, secondary fiber from recycled paper purchased or manufactured, paper products manufactured from purchased pulp by product type, paper converted into paperboard products by product type, and the quantity of coated or laminated products by paper product type.

NOTE: Authority cited: Sections 39600, 39601, 39607, 39607.4, 41511, 38510, and 38530, Health and Safety Code. Reference: Sections 39600, 41511, and 38530, Health and Safety Code.

§ 95120. Iron and Steel Production

The operator of a facility who is required to report under section 95101 of this article, and who is not eligible for abbreviated reporting under section 95103(a), must comply with Subpart Q of 40 CFR Part 98 (40 CFR §§98.170 to 98.188) in reporting annual stationary combustion and process emissions from iron and steel production to ARB, except as otherwise provided in this section.

(a) *CO_2 from Fossil Fuel Combustion.* When calculating CO_2 emissions from fossil fuel combustion at a stationary combustion unit under §98.172(a), the operator must use a method in §98.33(a)(1) to §98.33(a)(4) as specified by fuel type in section 95115 of this article.

(b) *Monitoring, Data and Records.* For each emissions calculation method chosen under section 95120(a), the operator must meet the applicable requirements for monitoring, missing data procedures, data reporting, and records retention that are specified in 40 CFR §98.34 to §98.37, except as modified in sections 95115, 95120(c), and 95129 of this article.

(c) *Missing Data Substitution Procedures.* The operator must comply with 40 CFR §98.175 when substituting for missing data, except as otherwise provided in paragraphs (1)-(2) below.

(1) To substitute for missing data for emissions reported under section 95115 of this article (stationary combustion units and units using continuous emissions monitoring systems), the operator must follow the requirements of section 95129 of this article.

(2) If monthly mass or volume of carbon-containing inputs and outputs are missing when using the carbon mass balance procedure in 40 CFR §98.173(b)(1), the operator must apply substitute values according to the procedures in paragraphs (A)-(B) below.

(A) If the data capture rate is at least 80 percent for the data year, the operator must substitute for each missing value based on the best available estimate based on information used for accounting purposes (such as purchase records).

(B) If the data capture rate is less than 80 percent for the data year, the operator must substitute each missing value with the maximum throughput capacity of the system.

(3) The operator must document and retain records of the procedure used for all missing data estimates pursuant to the recordkeeping requirements of section 95105.

(d) *Additional Data to Support Benchmarking.* In addition to the information required by 40 CFR §§98.176, the operator must report the annual production of primary iron and steel products in metric tons and a description of the product(s).

NOTE: Authority cited: Sections 39600, 39601, 39607, 39607.4, 41511, 38510, and 38530, Health and Safety Code. Reference: Sections 39600, 41511, and 38530, Health and Safety Code.

§ 95121. Suppliers of Transportation Fuels.

Any position holder, enterer, refiner, or biomass-derived fuel producer who is required to report under section 95101 of this article must comply with Subpart MM of 40 CFR Part 98 (§§98.390 to 98.398) in reporting annual emissions to ARB, except as otherwise provided in this section.

(a) *GHGs to Report.*

(1) In addition to the CO_2 emissions specified under 40 CFR §98.392, all refiners that produce liquefied petroleum gas must report the CO_2, CH_4, N_2O and CO_2e emissions that would result from the complete combustion or oxidation of the annual quantity of liquefied petroleum gas (ex refinery gate), except for products for which a final destination outside California can be demonstrated.

(2) Refiners, position holders, and enterers of fossil fuels and biomass-derived fuels and producers of biomass-derived 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 petroleum product or biomass-derived fuel listed in Tables MM-1 or MM-2 of 40 CFR Part 98, except that distillate fuel oil is limited to diesel fuel as defined in this regulation and except for products for which a final destination outside California can be demonstrated. No fuel shall be reported as finished fuel. Fuels must be reported as the blendstock or diesel fuel plus any other components.

(b) *Calculating GHG emissions.*

(1) Refiners, position holders at California terminals, enterers who bring fuel into California outside the bulk transfer/terminal system, and biomass-derived fuel producers must use Equation MM-1 as specified in 40 CFR §98.393(a)(1) to estimate the CO_2 emissions that would result from the complete combustion of the product removed from the rack (for refiners and position holders), imported (by enterers), sold to unlicensed entities as specified in section 95121(d)(3) (by refiners), or produced (by biomass-derived fuel producers). For fuels that are mixtures of multiple components, emissions must be reported for each

individual component separately, and not as finished motor gasoline, biofuel blends, or other similar finished fuel. Emission factors must be taken from column C of 40 CFR Part 98 Table MM-1 as specified in Calculation Method 1 of 40 CFR §98.393(f)(1).

(2) Refiners that produce liquefied petroleum gas must use Equation MM-1 as specified in 40 CFR §98.393(a)(1) to estimate the CO_2 emissions that would result from the complete combustion of the product supplied. For calculating the emissions from liquefied petroleum gas, the emissions from the individual components must be summed. Emission factors must be taken from column C of 40 CFR Part 98 Table MM-1 as specified in Calculation Method 1 of 40 CFR §98.393(f)(1).

(3) Refiners, position holders at California terminals, enterers outside of the bulk transfer/terminal system, and biomass-derived fuel producers must estimate and report CH_4 and N_2O emissions using Equation C–8 and Table C-2 as described in 40 CFR §98.33(c)(1).

(4) All fuel suppliers in this section must estimate CO_2e emissions using the following equation:

$$CO_2e = \sum_{i=1}^{n} GHG_i \times GWP_i$$

Where:

CO_2e = Carbon dioxide equivalent, metric tons/year.

GHG_i = Mass emissions of CO_2, CH_4, N_2O from fuels combusted or oxidized.

GWP_i = Global warming potential for each greenhouse gas from Table A-1 of 40 CFR Part 98.

n = Number of greenhouse gases emitted.

(c) *Monitoring and QA/QC Requirements.* For the emissions calculation method chosen under section 95121(b), the operator must meet all the monitoring and QA/QC requirements as specified in 40 CFR §98.394, and the requirements of 40 CFR §98.3(i) as further specified in section 95103 of this article and below.

(1) Position holders are exempt from 40 CFR §98.3(i) calibration requirements except when the fuel supplier and fuel receiver have common ownership or are owned by subsidiaries or affiliates of the same company. In such cases the 40 CFR §98.3(i) calibration requirements apply, unless:

(A) The fuel supplier does not operate the fuel billing meter;
(B) The fuel billing meter is also used by companies that do not share common ownership with the fuel supplier; or
(C) The fuel billing meter is sealed with a valid seal from the county sealer of weights and measures and the operator has no reason to suspect inaccuracies.

(2) As required by 40 CFR §98.394(a)(1)(iii), for products that are liquid at 60 degrees Fahrenheit and one standard atmosphere, the volume reported must

be temperature- and pressure-adjusted to these conditions. For liquefied petroleum gas the volume reported must be temperature-adjusted to 60 degrees Fahrenheit.

(d) *Data Reporting Requirements.* In addition to reporting the information required in 40 CFR §98.3(c), the following entities must also report the information identified below:

(1) California position holders must report the annual quantity in barrels, as reported by the terminal operator, and as corrected to reflect the individual components of the product, for each petroleum product or biomass-derived fuel listed in Tables MM-1 and MM-2 of 40 CFR Part 98 that is delivered across the rack in California, except that distillate fuel oil is limited to diesel fuel and except for products for which a final destination outside California can be demonstrated.

(2) California position holders that are also terminal operators and refiners with on-site racks must report the annual quantity in barrels delivered across the rack corrected to reflect the individual components of the product, for each petroleum product or biomass-derived fuel listed in Tables MM-1 and MM-2 of 40 CFR Part 98, except distillate fuel oil is limited to diesel fuel and except for products for which a final destination outside California can be demonstrated.

(3) Refiners that supply fuel within the bulk transfer system to entities not licensed by the California Board of Equalization as a fuel supplier must report the annual quantity in barrels delivered corrected to reflect the individual components of the product, for each petroleum product or biomass-derived fuel listed in Tables MM-1 and MM-2 of 40 CFR Part 98, except Distillate Fuel Oil is limited to diesel fuel and except for products for which a final destination outside California can be demonstrated.

(4) Enterers must report the annual quantity in barrels, as reported on the bill of lading or other shipping documents, corrected to reflect the individual components of the product, for each petroleum product or biomass-derived fuel listed in Tables MM-1 and MM-2 of 40 CFR Part 98 that is imported into California, except that distillate fuel oil is limited to diesel fuel and except for products for which a final destination outside California can be demonstrated.

(5) Producers of biomass-derived fuels in California must report the annual quantity in barrels, as measured at a custody transfer meter or listed on a bill of lading, corrected to reflect the individual components of the product, for each fuel listed in Tables MM-1 and MM-2 of 40 CFR Part 98 that is delivered in California, except for products for which a final destination outside California can be demonstrated. This requirement does not apply to the annual reporting of the total volume of biodiesel, renewable diesel, and denatured fuel ethanol produced or imported, if this information has been provided under the requirements of title 17, California Code of Regulations, sections 95480-95490 (Low Carbon Fuel Standard).

(6) Biomass-derived fuel producers in California that blend biomass-derived fuel with fossil fuels outside the bulk transfer/terminal system must indicate the

supplier or source of the fossil-based fuels when reporting component volumes.

(7) In addition to the information required in 40 CFR §98.396 petroleum refineries must also report the volume of liquefied petroleum gas in barrels supplied in California as well as the volumes of the individual components as listed in 40 CFR 98 Table MM-1, except for products for which a final destination outside California can be demonstrated.

(8) All fuel suppliers identified in this section must also report CO_2, CO_2 from biomass-derived fuels, CH_4, N_2O and CO_2e emissions in metric tons that would result from the complete combustion or oxidation of each petroleum product, liquefied petroleum gas, or biomass-derived fuel reported in this section, calculated according to section 95121(b).

(9) Enterers and biomass-derived fuel producers who deliver fuel to position holders at terminals or refiners must report the name of the recipient and the volumes delivered according to the bill of lading or other sales document.

(e) *Procedures for Missing Data.* For quantities of fuels that are purchased, sold, or transferred in any manner, fuel suppliers must follow the missing data procedures specified in 40 CFR §98.395. The supplier must document and retain records of the procedure used for all missing data estimates pursuant to the recordkeeping requirements of section 95105. If any combination of data elements used to measure emissions from fuel or direct measurement are missing, such that more than 20 percent of annual emissions cannot be directly calculated, a nonconformance occurs for the emissions source. The missing data must still be substituted as specified in 40 CFR §98.395. For the purpose of applying this provision, data substituted using an approved interim data collection procedure will be considered captured data and not count toward the 20 percent missing data limitation.

NOTE: Authority cited: Sections 39600, 39601, 39607, 39607.4, 41511, 38510, and 38530, Health and Safety Code. Reference: Sections 39600, 41511, and 38530, Health and Safety Code.

§ 95122. Suppliers of Natural Gas, Natural Gas Liquids, and Liquefied Petroleum Gas.

Any supplier of natural gas or natural gas liquids who is required to report under section 95101 must comply with Subpart NN of 40 CFR Part 98 (§§98.400 to 98.408) in reporting annual emissions to ARB, except as otherwise provided in this section.

(a) *GHGs to Report.*

(1) In addition to the CO_2 emissions specified under 40 CFR §98.402(a), natural gas liquid fractionators must report the CO_2, CH_4, N_2O and CO_2e emissions that would result from the complete combustion or oxidation of liquefied

petroleum gas sold or delivered to others, except for products for which a final destination outside California can be demonstrated.

(2) In addition to the CO_2 emissions specified under 40 CFR §98.402(b), local distribution companies must report the CO_2, CO_2 from biomass-derived fuels, CH_4, N_2O, and CO_2e emissions from the complete combustion or oxidation of the annual volume of natural gas provided to all entities on their distribution systems in California

(3) The California consignee for liquefied petroleum gas will report the CO_2, CH_4, N_2O and CO_2e emissions that would result from the complete combustion or oxidation of the annual quantity of liquefied petroleum gas imported into the state, except for products for which a final destination outside California can be demonstrated.

(b) *Calculating GHG Emissions.*

(1) Natural gas liquid fractionators must use calculation methodology 1 as specified in 40 CFR §98.403(a)(1) or calculation methodology 2 as specified in 40 CFR §98.403(a)(2) to estimate the CO_2 emissions that would result from the complete combustion of the product supplied. For calculating the emissions from liquefied petroleum gas, the fractionators must sum the emissions from the individual constituents. For components of liquefied petroleum gas not listed in Table NN-1 of 40 CFR 98, values from Tables MM-1 and C-1 of 40 CFR 98 must be used as appropriate.

(2) Local distribution companies must estimate CO_2 emissions at the state border or city gate for pipeline quality natural gas using calculation methodology 1 as specified in 40 CFR §98.403(a)(1), using the reporter specific weighted yearly average higher heating value and a default or reporter specific CO_2 emission factor. Receipts of pipeline quality natural gas from in-state natural gas producers and net volume of pipeline quality natural gas injected into storage are estimated according to 40 CFR §98.403(b)(3) using reporter specific emission factors. For 40 CFR §98.403(b)(3), reporter specific emission factors will be calculated as the product of the local distribution company's own weighted yearly average HHV measurement and the default emission factor, from Table NN-1 of 40 CFR Part 98, or reporter specific CO_2 emission factor for natural gas. Alternatively, local distribution companies may estimate CO_2 emissions from pipeline quality natural gas at the city gate as the sum of the products of the volume of gas received at each city gate and the reporter specific HHV measurement at the receipt location recorded at a minimum of a monthly frequency multiplied by the default emission factor from Table NN-1 of 40 CFR Part 98, or reporter specific CO_2 emission factor for natural gas. Receipts from in-state natural gas producers and net volume of natural gas injected into storage may also be estimated according to the above method. For natural gas outside the range of 970-1100 Btu/scf the local distribution company must estimate CO_2 emissions using the Tier 3 methodologies specified in 40 CFR §98.33(a)(3)(iii) with monthly carbon content samples

used to calculate the annual carbon content as specified in 40 CFR §98.33(a)(2)(ii)(A).

When calculating total CO_2 emissions for California, the equation below must be used:

$$CO_2 = \sum CO_{2i} - \sum CO_{2I}$$

Where:
CO_2 = Total emissions
CO_{2i} = Emissions from natural gas received at the state border or city gate
CO_{2I} = Emissions from storage and direct deliveries from producers

For the purpose of this section, a public utility gas corporation may use the California border as the city gate.

(3) Natural gas liquid fractionators and local distribution companies must estimate and report CH_4 and N_2O emissions using equation C-8 and Table C-2 as described in 40 CFR §98.33(c)(1) for all fuels where annual CO_2 emissions are required to be reported by 40 CFR §98.406 and this section. Local distribution companies must use the reporter specific weighted yearly average higher heating value when calculating emissions.

(4) Local distribution companies must separately and individually calculate end-user emissions of CH_4, N_2O, CO_2 from biomass-derived fuels, and CO_2e by replacing CO_2 in the equation in section 95122(b)(2) with CH_4, N_2O, CO_2 from biomass-derived fuels, and CO_2e.

(5) The California consignee for liquefied petroleum gas must use calculation methodology 2 described in 40 CFR §98.403(a)(2) for calculating CO_2 emissions. The consignee must sum the emissions from the individual components of the liquefied petroleum gas, to calculate the total emissions. For components of liquefied petroleum gas not listed in Table NN-1 of 40 CFR 98, values from Tables MM-1 and C-1 of 40 CFR 98 must be used as appropriate. If the composition is not supplied by the producer, the consignee must use the default value for liquefied petroleum gas presented in Table C-1 of 40 CFR Part 98.

(6) The California consignee for liquefied petroleum gas must estimate and report CH_4 and N_2O emissions using equation C-8 and Table C-2 as described in 40 CFR §98.33(c)(1).

(7) All fuel suppliers in this section must also estimate CO_2e emissions using the following equation

$$CO_2e = \sum_{i=1}^{n} GHG_i \times GWP_i$$

Where:
CO_2e = Carbon dioxide equivalent, metric tons/year.
GHG_i = Mass emissions of CO_2, CH_4, N_2O from fuels combusted or oxidized.

GWP_i = Global warming potential for each greenhouse gas from Table A-1 of 40 CFR Part 98.
n = Number of greenhouse gases emitted.

(c) *Monitoring and QA/QC Requirements.* For each emissions calculation method chosen under this section, the supplier must meet all monitoring and QA/QC requirements specified in 40 CFR §98.404, except as modified in sections 95103, 95115, and below.

(1) All natural gas suppliers must measure required values at least monthly.
(2) All natural gas suppliers must determine reporter specific HHV at least monthly, or if the local distribution company does not make its own measurements according to standard business practices it must use the delivering pipeline measurement.
(3) All natural gas liquid fractionators must sample for composition at least monthly.
(4) All California consignees of liquefied petroleum gas must record composition, if provided by the supplier, and quantity in barrels, corrected to 60 degrees Fahrenheit, for each shipment received.

(d) *Data Reporting Requirements.*

(1) For the emissions calculation method selected under section 95122(b), natural gas liquid fractionators must report, in addition to the data required by 40 CFR §98.406(a), the annual volume of liquefied petroleum gas, corrected to 60 degrees Fahrenheit, sold or delivered to others, except for products for which a final destination outside California can be demonstrated. Natural gas liquid fractionators must report the annual quantity of liquefied petroleum gas delivered to others as the total volume in barrels as well as the volume of its individual components for all components listed in 40 CFR 98 Table MM-1. Fractionators must also include the annual CO_2, CH_4, N_2O, and CO_2e mass emissions (metric tons) from the volume of liquefied petroleum gas reported in 40 CFR §98.406(a)(5) as modified by this regulation, calculated in accordance with section 95122(b)(1)-(3).
(2) For the emissions calculation method selected under section 95122(b), local distribution companies must report all the data required by 40 CFR §98.406(b) subject to the following modifications:

(A) Publicly-owned natural gas utilities that report in-state receipts at the city gate under 40 CFR §98.406(b)(1) must also identify each delivering entity by name and report the monthly volumes received in Mscf and the monthly weighted average HHV.
(B) Local distribution companies that report under 40 CFR §98.406(b)(1) through (b)(7) must also report the annual energy of natural gas in MMBtu associated with the volumes.

(C) In addition to the requirements in 40 CFR §98.406(b)(8), local distribution companies must also include CO_2, CO_2 from biomass-derived fuels, CH_4, N_2O, and CO_2e annual mass emissions in metric tons calculated in accordance with 40 CFR §98.403(a) and (b)(1) through (b)(3) as modified by section 95122(b).

(D) For each publicly-owned natural gas utility, local distribution companies must report the monthly volumes, monthly weighted average HHV, and the information required in 40 CFR §98.406(b)(12), including EIA number. These requirements are in addition to the requirements of 40 CFR §98.406(b)(6).

(E) For each customer, local distribution companies that report under 40 CFR §98.406 (b)(7) must report the annual volumes in Mscf, annual energy in MMBtu, and customer information required in 40 CFR §98.406(b)(12).

(F) Local distribution companies that report under 40 CFR §98.406(b)(9) must report annual CO_2, CO_2 from biomass-derived fuel, CH_4, N_2O, and CO_2e emissions (metric tons) that would result from the complete combustion or oxidation of the natural gas supplied to all entities calculated in accordance with section 95122(b)(2), (b)(4), and (b)(7).

(3) In addition to the information required in 40 CFR §98.3(c), the operator of non-utility interstate pipelines must report the customer name, address, and customer number along with monthly volumes of natural gas, in Mscf, and the corresponding weighted average monthly HHV in Btu/scf for natural gas delivered to each end user or wholesale customer, including themselves.

(4) In addition to the information required in 40 CFR §98.3(c), the operator of an intrastate pipeline not subject to Subpart NN of 40 CFR Part 98 that delivers natural gas directly to end users or wholesale customers must follow the reporting requirements described under Subpart NN and this section for local distribution companies. In lieu of the information specified by 40 CFR §98.406(b)(1), the operator must report volumes (Mscf) of natural gas received by the intrastate pipeline from interconnects with local distribution companies, interstate pipelines, or other intrastate pipelines.

(5) In addition to the information required in 40 CFR §98.3(c), the California consignee for liquefied petroleum gas must report the annual quantity of liquefied petroleum gas imported as the total volume in barrels as well as the volume of its individual components for all components listed in 40 CFR 98 Table MM-1, if supplied by the producer, and report CO_2, CH_4, N_2O, and CO_2e annual mass emissions in metric tons using the calculation methods in section 95122(b).

(e) *Procedures for estimating missing data.* Suppliers must follow the missing data procedures specified in 40 CFR §98.405. The operator must document and retain records of the procedure used for all missing data estimates pursuant to the recordkeeping requirements of section 95105. If any combination of data elements used to measure emissions from fuel or direct measurement is missing, such that

more than 20 percent of annual emissions cannot be directly calculated, a nonconformance occurs for the emissions source. The missing data must still be substituted as specified in this section. For the purpose of applying this provision, data substituted using an approved interim data collection procedure will be considered captured data and not count toward the 20 percent missing data limitation.

NOTE: Authority cited: Sections 39600, 39601, 39607, 39607.4, 41511, 38510, and 38530, Health and Safety Code. Reference: Sections 39600, 41511, and 38530, Health and Safety Code.

§ 95123. Calculation Methods for Suppliers of Carbon Dioxide.

Any supplier of carbon dioxide who is required to report under section 95101 of this article must comply with Subpart PP of 40 CFR Part 98 (§§98.420 to 98.428) in reporting to ARB, except as otherwise provided in this section.

(a) When reporting imported and exported quantities of CO_2 as required in 40 CFR §98.422, the supplier must also report quantities of carbon dioxide imported into or exported from the State of California.

(b) *Missing Data Substitution Procedures.* The supplier must comply with 40 CFR §98.165 when substituting for missing data, except as otherwise provided below.

(1) For all data required for emissions calculations in this section, the supplier must follow the requirements of paragraphs (A)-(D) below.

(A) If the data capture rate is at least 90 percent for the data year, the supplier must substitute each missing value using the best available estimate of the parameter, based on all available process data.

(B) If the data capture rate is at least 80 percent but not at least 90 percent for the data year, the supplier must substitute each missing value with the highest quality assured value recorded for the parameter during the given data year, as well as the two previous data years.

(C) If the data capture rate is less than 80 percent for the data year, the supplier must substitute each missing value with the highest quality assured value recorded for the parameter in all records kept according to section 95105(a).

(D) The supplier must document and retain records of the procedure used for all missing data estimates pursuant to the recordkeeping requirements of section 95105.

NOTE: Authority cited: Sections 39600, 39601, 39607, 39607.4, 41511, 38510, and 38530, Health and Safety Code. Reference: Sections 39600, 41511, and 38530, Health and Safety Code.

Subarticle 3
Additional Requirements for Reported Data

§95125. Additional Calculation Methods.

[Repealed]

§ 95129. Substitution for Missing Data Used to Calculate Emissions from Stationary Combustion and CEMS Sources.

In lieu of the requirements for estimating missing data in Subparts C and D of 40 CFR Part 98, the operator of a facility who is reporting emissions under section 95115 or 95112 of this article, and who is not eligible for abbreviated reporting under section 95103(a), must follow the applicable procedures of this section for estimating missing or invalid data. The operator must include the substituted data in the GHG emissions data report and maintain all records, calculations, and data used to estimate substituted data according to the requirements of section 95105 and 40 CFR Part 98. Alternatively, under the limited circumstances specified in this section for equipment breakdown, the operator may request approval of an interim data collection procedure as specified in paragraphs 95129(h)-(i). For units combusting pure biomass-derived fuels, the operator who is reporting emissions must follow either the requirements below or the requirements of 40 CFR §98.35.

(a) *Missing Data Substitution Procedures for Units Reporting Under 40 CFR Part 75.* The operator of a unit that is subject to reporting under 40 CFR Part 75 must follow the applicable missing data substitution procedures in Part 75 for CO_2 concentration, stack gas flow rate, fuel flow rate, high heat value, and fuel carbon content. Paragraphs (b) through (g) of this section do not apply to these units.

(b) *Missing Data Substitution Procedures for Other Units Equipped with CEMS.* The operator of a stationary combustion unit who monitors and reports emissions and heat input data for that unit under section 95115 of this article using Tier 4 of Subpart C (40 CFR §98.33(a)(4)) must follow the applicable missing data substitution procedures in 40 CFR Part §75.31 to 75.37 (revised as of July 1, 2009).

(c) *Missing Data Substitution Procedures for Fuel Characteristic Data.* When the applicable emissions estimation methods of this article require periodic collection of fuel characteristic data (including carbon content, high heat value, and molecular weight) the operator must demonstrate every reasonable effort to obtain a fuel characteristic data capture rate of 100 percent for each data year. When fuel characteristic data of a required fuel sample are missing or invalid, the operator must first attempt to either reanalyze the original sample or perform the fuel analysis on a backup sample, or replacement sample from the same collection period as specified in 40 CFR §98.34(a)(2)-(3), to obtain valid fuel characteristic data. If the sample collection period has elapsed and no valid fuel characteristic data can be obtained from a backup or replacement sample, the operator must substitute for the missing data the values obtained according to the procedures in paragraphs

95129(c)(1)-(3). The data capture rate for the data year must be calculated as follows for each type of fuel and each fuel characteristic parameter:

Data capture rate = S / T x 100%

Where:

S = Number of fuel samples for which valid fuel characteristic data were obtained according to the applicable sampling requirements (including sampling schedule)

T = Total number of fuel samples required by the applicable sampling requirements

(1) If the fuel characteristic data capture rate is at least 90.0 percent for the data year, the operator must substitute the arithmetic average of the values of that parameter immediately preceding and immediately following the missing data incident that are representative of the fuel type. If the "after" value has not been obtained by the time that the GHG emissions data report is due, the operator must use the "before" value for missing data substitution.

(2) If the fuel characteristic data capture rate is at least 80.0 percent but not more than 90.0 percent for the data year, the operator must substitute for each missed value with the highest valid value recorded for that type of fuel during the data year as well as the two previous data years.

(3) If the operator is unable to obtain fuel characteristic data such that less than 80.0 percent of emissions from a source are directly accounted for, a nonconformance results for the emissions source. The operator must then substitute for each missed data point the greater of the following:

(A) the highest valid value recorded for that type of fuel for all records kept under the requirements of section 95105, or

(B) the default value in Table 1 of this section (for carbon content) or Table C-1 of 40 CFR Part 98 (for high heat value). If a substitute value is not available in Table 1 of this section or Table C-1 of 40 CFR Part 98, the operator must substitute the highest value recorded for that type of fuel for all records kept pursuant to the requirements of section 95105.

Table 1. Default Carbon Content

Parameter	Missing Data Value
Anthracite Coal	*90%*
Bituminous	*85%*
Subbituminous/Lignite	*75%*
Oil	*90%*
Natural Gas	*75%*
Other Gaseous Fuels	*90%*

(d) *Missing Data Substitution Procedures for Fuel Consumption Data.* For each fuel type, when annual fuel consumption data that meet the accuracy requirements of this article are available at the facility level, but such data are missing or invalid at

the unit level, the operator must either estimate missing unit-level fuel consumption data using available process data that are routinely measured at the facility (e.g., electrical load, steam production, operating hours), or use an applicable missing data substitution procedure from paragraphs 95129(d)(1)-(3). If a portion of annual fuel consumption data at the facility level is missing or cannot be determined at the accuracy required by this article, the operator must use the applicable missing data substitution procedure from paragraphs 95129(d)(1)-(3) below.

(1) *Continuous Fuel Flow Rate Data Using Load Ranges.* The requirements of this paragraph apply to sources that combust gaseous or liquid fuels, produce electrical or thermal output, use a fuel flowmeter system to continuously measure fuel flow rate; and are equipped with a data acquisition and handling system (DAHS) that continuously records fuel flow rates and measured electrical or thermal output on an hourly basis, which enables segregation of the fuel flow rate data into bins. The operator of such sources must substitute missing fuel flow rate data according to this paragraph.

Whenever quality-assured fuel flow rate data are missing and there is no backup system available to record the fuel flow rate, the operator must use the following procedures to account for the flow rate of fuel combusted at the source for each hour during the missing data period. Before using these procedures, operators must establish load ranges for the affected sources using the procedures in paragraph (f) of this section.

When load ranges are used for estimating missing fuel flow rate data, the operator must create and maintain separate fuel-specific databases for the source. The database for each type of fuel combusted must include the hours in which the fuel is combusted alone at the source and the hours in which it is co-fired with any other fuel types. The database must record fuel flow rate and corresponding electrical output or thermal output, and assign these values into the established load bins. To be eligible to use the missing data procedures in this paragraph, measured electrical output or thermal output must be available for the hour(s) in which fuel flow rate data are missing. If output data are missing, the operator must follow the requirements of paragraph (d)(3).

(A) *Single Fuel Type.* For missing data periods that occur when only one type of fuel is being combusted, the operator must provide substitute data for each hour of the missing data period as follows: Substitute the arithmetic average of the hourly quality-assured fuel flow rate(s) measured and recorded by a fuel flowmeter system at the corresponding operating source load range during the previous 720 operating hours in which the source combusted only that same fuel. If 720 hours of fuel flow rate data are not available at the corresponding load range, the operator may combine available data with data from higher load ranges if available until 720 hours are reached. If 720 hours of quality-assured fuel flow rate data are not available when combined with higher load

ranges, the operator must substitute the maximum potential fuel flow rate for each hour of the missing data period.

(B) *Multiple Fuel Types.* For missing data periods that occur when two or more different types of fuel are being co-fired, the operator must provide substitute fuel flow rate data for each hour of the missing data period as follows:

1. Substitute the maximum hourly quality-assured fuel flow rate(s) measured and recorded by a fuel flowmeter system at the corresponding operating source load range during the previous 720 operating hours when the fuel for which the flow rate data are missing was co-fired with any other type of fuel. If 720 hours of fuel flow rate data are not available at the corresponding load range, data from higher load ranges if available may be combined until 720 hours are reached. If 720 hours of quality-assured fuel flow rate data are not available when combined with higher load ranges, the operator must substitute the maximum potential fuel flow rate for each hour of the missing data period.
2. If, during an hour in which different types of fuel are co-fired, quality-assured fuel flow rate data are missing for two or more of the fuels being combusted, apply the procedures in subparagraph (d)(1)(B)1. separately for each type of fuel.
3. If the missing data substitution required in subparagraphs (d)(1)(B)1.-2. causes the reported hourly heat input rate based on the combined fuel usage to exceed the maximum rated hourly heat input of the unit, adjust the substitute fuel flow rate value(s) so that the reported heat input rate equals the unit's maximum rated hourly heat input.

(C) *Lookback Period.* In any case where the missing data provisions of this section require substitution of data measured and recorded more than three years (26,280 clock hours) prior to the date and time of the missing data period, the operator must substitute the maximum potential fuel flow rate for each hour of the missing data period. In addition, for sources in operation less than three years (26,280 clock hours), until 720 hours of quality-assured fuel flowmeter data are available for the lookback periods described in subparagraphs (d)(1)(A) and (d)(1)(B), the methodology in section (d)(3) must be used to determine the appropriate substitute data values.

(2) *Fuel Consumption Data Without Load Ranges.* This paragraph applies to fuel combusting units that cannot use the missing data procedures in paragraph (d)(1). Whenever quality-assured fuel consumption data are missing and there is no backup system available to record the fuel consumption, the operator must use the procedures in this paragraph to account for the consumption of fuel combusted at the unit during the missing data period. To be eligible to use the missing data procedures in this paragraph (d)(2), the

operator must monitor and keep records of fuel consumption on a regular basis. For fuels that are combusted less than 180 days in a calendar year, the operator must record fuel consumption at least daily on each day the fuel is combusted. For all other sources or fuels, the operator must record fuel consumption at least weekly.

The data capture rate for the data year must be calculated as follows for each unit with missing fuel consumption data:

Data capture rate = S / T x 100%

Where:

S = Number of fuel monitoring periods (e.g., days or weeks) in the data year for which valid measured fuel consumption data are available. Do not include fuel monitoring periods when the fuel was not combusted at the unit.

T = Total number of fuel monitoring periods (e.g., days or weeks) that the unit is operated in the data year.

(A) *Single Fuel.* For missing data periods that occur when only one type of fuel is being combusted, the operator must provide substitute data for each missing data period as follows:

1. If the fuel consumption data capture rate is equal to or greater than 95.0 percent during the data year, the operator must develop an estimate based on available process data that are routinely measured and recorded at the unit (e.g., electrical load, steam production, operating hours).
2. If the fuel consumption data capture rate is equal to or greater than 90.0 percent but less than 95.0 percent during the data year, the operator must calculate substitute data as the 90th percentile value of the fuel consumption data recorded for the data year as well as the two previous data years.
3. If the fuel consumption data capture rate is at least 80.0 percent but less than 90.0 percent during the data year, the operator must calculate substitute data as the 95th percentile value of the fuel consumption data recorded for the data year as well as the two previous data years.
4. If the fuel consumption data capture rate is less than 80.0 percent during the data year, a nonconformance occurs for the emissions source, and the operator must apply as substitute data the maximum potential fuel consumption rate.

(B) *Multiple Fuels.* For missing data periods that occur when two or more different types of fuel are being co-fired, the operator must provide substitute fuel flow rate data for each missing data period as follows:

1. If the fuel consumption data for a single fuel are missing, provide substitute fuel consumption data for the missing data period using the procedures in paragraph 95129(d)(2)(A).
2. If fuel consumption data are missing for two or more of the fuels being combusted, apply the procedures in section 95129(d)(2)(A) (as applicable) separately for each type of fuel.
3. If the missing data substitution required in section 95129(d)(2)(A)causes the reported heat input rate based on the combined fuel usage to exceed the maximum rated heat input of the source, adjust the substitute fuel consumption value(s) so that the reported heat input rate equals the source's maximum rated heat input.

(C) *Prorating Substitute Value.* When applying the procedures in subparagraphs (d)(2)(A)-(B), if an individual missing data period is shorter than the fuel consumption data monitoring period, the operator must prorate the specified value for the fuel consumption data monitoring period by the missing data period. For example, for a unit with a missing data period length of one day but weekly fuel consumption monitoring schedule, the operator may divide the substitute value, estimated on a weekly basis, by the number of days the unit operates in a week to obtain the substitute value for the missing data day.

(3) *Alternate Missing Data Procedure for Fuel Consumption Data.* This paragraph applies to fuel combusting units that cannot use the missing data procedures in paragraphs (d)(1) and (d)(2). If fuel consumption data are missing or invalid for a fuel combusting unit, and fuel consumption data at the facility level or aggregated unit level cannot be determined at the accuracy required by this article, the operator must substitute for each hour of missing data using the maximum potential fuel consumption rate for the unit. If fuel consumption data at the facility level or at a higher aggregated-units level are available and meet the accuracy requirements of this article, the operator may estimate the missing unit-level fuel consumption data using available process data that are routinely measured at the facility (e.g., electrical load, steam production, operating hours).

(e) *Missing Data Substitution Procedures for Steam Production.* The operator of a steam-producing unit who calculates and reports emissions using Equation C-2c in 40 CFR §98.33(a)(2) must apply the procedures in this paragraph to substitute for missing steam production data, unless a backup system to record steam production is available. For sources for which steam production data are not used to calculate emissions, the operator may develop an estimate using available process data that are routinely measured and recorded at the unit (e.g., electrical load, steam production, product output, operating hours) to estimate missing steam production.

If hourly steam production data are not available at the facility, the operator must record steam production data at least weekly and use the weekly records for substituting the missing steam production data. The operator must prorate the steam data using the same procedure in paragraph (d)(2)(C).

The data capture rate for the data year must be calculated as follows for each unit with a missing data period:

Data capture rate = S / T x 100%

Where:

S = Number of monitoring intervals (e.g. hourly, daily, or weekly) with valid measured steam production data.

T = Total number of monitoring intervals that the unit is operated in the data year.

(1) If the steam production data capture rate is at least 90.0 percent during the data year, the operator must develop an estimate using available process data that are routinely measured and recorded at the unit (e.g., electrical load, steam production, product output, and operating hours).

(2) If the steam production data capture rate is at least 80.0 percent but less than 90.0 percent during the data year, the operator must calculate substitute data as the 90th percentile value of the steam production data recorded for the data year.

(3) If the steam production data capture rate is less than 80.0 percent during the data year, a nonconformance occurs for the emissions source, and the operator must substitute the highest valid steam production value recorded in all records kept according to section 95105(a).

(f) *Procedure for Establishing Load Ranges.* This paragraph is applicable to units that produce electrical output or thermal output. For a single unit, the operator must establish ten operating load ranges, each defined in terms of percent of the maximum hourly average gross load of the unit, in gross megawatts (MW). (Do not use integrated hourly gross load in MWh.) For a cogenerating unit or other unit at which some portion of the heat input is not used to produce electricity, or for a unit for which hourly average gross load in MW is not recorded separately, the operator must use the hourly gross steam load of the unit, in pounds of steam per hour at the measured temperature (°F) and pressure (psia), instead of gross MW.

Beginning with the first hour of unit operation after installation and certification of the fuel flowmeter, for each hour of unit operation the operator must record a number, 1 through 10, that identifies the operating load range corresponding to the integrated hourly gross load of the unit(s) recorded for each unit operating hour. The operator must calculate maximum values and percentile values determined by this procedure using bias adjusted values in the load ranges. When a bias adjustment is necessary for the fuel flowmeter, the operator must apply the adjustment factor to

all data values placed in the load ranges. The operator must use the calculated maximum values and percentile values to substitute for missing flow rate according to the procedures in paragraph (d)(1) of this section.

(g) *Executive Officer Approved Load Range.* An operator may petition the Executive Officer for approval to use an alternate load based methodology for substituting missing data to using the procedures in paragraph 95129(d)(1). The operator must be able to prove to the satisfaction of the Executive Officer that there is a direct correlation between fuel consumption and the proposed load metric. At a minimum, the operator will have a system in place that electronically measures and records fuel consumption and load at least hourly. The alternate load metric must be a metric that can be accurately measured, correlated to fuel consumption, and divided into ten operating load ranges. In order to verify the feasibility of the methodology the Executive Officer will require at least three years of fuel consumption and load data and may request up to the maximum years of data required to be retained under section 95105(a).

(h) *Procedure for Approval of Interim Fuel Analytical Data Collection Procedure During Equipment Breakdowns.*

(1) In the event of an unforeseen breakdown of the fuel characteristic data monitoring or fuel flow monitoring equipment used to estimate emissions under this article, the Executive Officer may authorize an operator to use an interim data collection procedure under the circumstances specified below. The operator must satisfactorily demonstrate to the Executive Officer that:

(A) The breakdown may result in a loss of more than 20 percent of a fuel characteristic or fuel usage data element for the data year, and back-up sampling for affected fuel characteristics is unavailable;
(B) The affected monitoring equipment cannot be promptly repaired or replaced without shutting down a process unit significantly affecting facility operations, or the monitoring equipment must be replaced and replacement equipment is not immediately available; and,
(C) The interim procedure will not remain in effect longer than is reasonably necessary for repair or replacement of the malfunctioning monitoring equipment.

(2) An operator seeking approval of an interim data collection procedure must, within sixty days of the monitoring equipment breakdown, submit a written request to the Executive Officer that includes all of the following:

(A) The proposed start date and end date of the interim procedure;
(B) A detailed description of what data are affected by the breakdown;
(C) A discussion of the accuracy of data collected during the interim procedure compared with the data collected under the usual procedure used by the operator;

(D) A demonstration that the criteria in paragraph (h)(1) are satisfied, and operator certification that no feasible alternative procedure exists that would provide more accurate emissions data.

(3) The Executive Officer may limit the duration of the interim data collection procedure to ensure the criteria in paragraph (h)(1) are met.

(4) When reviewing an interim data collection procedure, the Executive Officer shall determine whether the accuracy of data collected under the procedure is reasonably equivalent to data collected from properly functioning monitoring equipment, and if it is not, the relative accuracy to assign for purposes of assessing possible material misstatement under section 95131 of this article. Data collected pursuant to an approved interim data collection procedure shall be considered captured data for purposes of compliance with the capture rate requirements in this section.

(5) The Executive Officer shall provide written notification to the operator of approval or disapproval of the interim data collection procedure within sixty days of receipt of the request, or within thirty days of receipt of any additional information requested by the Executive Officer, whichever is later.

(i) *Procedure for Approval of Interim Data Collection Procedure During Breakdown for Units Equipped with CEMS.*

(1) In the event of an unforeseen breakdown of CEMS equipment at a combustion unit where the operator uses the Tier 4 Calculation Methodology (40 CFR 98.33(a)(4)) to monitor and report emissions under this article, the operator may request approval from the Executive Officer to temporarily use the Tier 2 Calculation Methodology (40 CFR 98.33(a)(2)) for natural gas, biomass, or municipal solid waste, or the Tier 3 Calculation Methodology (40 CFR 98.33(a)(3)) for other fuels, to calculate emissions during the equipment breakdown period. The operator must satisfactorily demonstrate to the Executive Officer that:

(A) The breakdown will result in a loss of more than 20 percent of the concentration, flow rate, or other information used to calculate and report annual emissions for the data year, and that back-up monitoring is unavailable;

(B) The affected monitoring equipment cannot be promptly repaired or replaced without shutting down a process unit significantly affecting facility operations, or the monitoring equipment must be replaced and replacement equipment is not immediately available; and,

(C) The interim procedure will not remain in effect longer than is reasonably necessary for repair or replacement of the malfunctioning monitoring equipment.

(2) The operator must collect fuel samples and comply with all applicable requirements of the Tier 2 or Tier 3 Calculation Methodology in 40 CFR

98.33(a)(2) or (3), as modified by section 95115 of this article, during the equipment breakdown period. Fuel characteristics data provided by the fuel suppliers can be used if available. The operator must, within sixty days of the monitoring equipment breakdown, submit a written request to the Executive Officer that includes all the following information:

(A) The proposed start date and end date of the interim procedure, including a demonstration that the interim procedure will not remain in effect longer than is reasonably necessary for repair or replacement of the malfunctioning equipment;
(B) A detailed description of what data are affected by the breakdown; and,
(C) An interim monitoring plan that meets the requirements of the Tier 3 Calculation Methodology as applicable by fuel type in section 95115.

(3) The Executive Officer may limit the duration of the interim data collection procedure to ensure the criteria in paragraph (i)(1) are met.
(4) The Executive Officer shall provide written notification to the operator of approval or disapproval of the interim data collection procedure within sixty days of receipt of the request, or within thirty days of receipt of any additional information requested by the Executive Officer, whichever is later.

(j) *Cumulative Missing Data Elements.* If any combination of data elements used to measure emissions from fuel or direct measurement is missing, such that more than 20 percent of annual emissions cannot be calculated from directly measured data, a nonconformance occurs for the emissions source. The missing data must still be substituted as specified in this section. For the purpose of applying this provision, data substituted using an approved interim data collection procedure will be considered captured data and not count toward the 20 percent missing data limitation.

NOTE: Authority cited: Sections 39600, 39601, 39607, 39607.4, 41511, 38510, and 38530, Health and Safety Code. Reference: Sections 39600, 41511, and 38530, Health and Safety Code.

Subarticle 4. Requirements for Verification of Greenhouse Gas Emissions Data Reports and Requirements Applicable to Emissions Data Verifiers; Requirements for Accreditation of Emissions Data and Offset Project Data Report Verifiers

§ 95130. Requirements for Verification of Emissions Data Reports.

The reporting entity who is required to report under section 95101 of this article, and who is not eligible for abbreviated reporting under section 95103(a), must obtain the services of an accredited verification body for purposes of verifying each emissions data report submitted under this article, as specified in section 95103(f).

(a) *Annual Verification.*

(1) Reporting entities required to obtain annual verification services as specified in section 95103(f) are subject to full verification requirements in the first year that verification is required in each compliance period. Upon receiving a positive verification statement under full verification requirements, the reporting entity may choose to obtain less intensive verification services for the remaining years of the compliance period. Full verification requirements shall apply at least once in each compliance period. Reporting entities subject to this section are required to obtain full verification services if any of the following apply:

(A) The emissions data report is for the 2011 data year;
(B) There has been a change in the verification body;
(C) An adverse verification statement or qualified positive verification statement was issued for the previous year;
(D) A change of ownership of the reporting entity occurred in the previous year;
(E) The total reported GHG emissions during the data year differs by greater than 25 percent relative to the preceding emission data report;
(F) The total reported MWh during the data year differs by greater than 25 percent relative to the preceding emission data report;

(2) Reporting entities subject to annual verification under section 95130 shall not use the same verification body or verifiers(s) for a period of more than six consecutive years, which includes any verifications conducted under this article and for the California Climate Action Registry, The Climate Registry, or Climate Action Reserve. If a reporting entity is required or elects to contract with another verification body or verifier(s), the reporting entity may contract verification services from the previous verification body or verifier(s) only after not using the previous verification body or verifiers(s) for at least three years.

NOTE: Authority cited: Sections 39600, 39601, 39607, 39607.4, 41511, 38510, and 38530, Health and Safety Code. Reference: Sections 39600, 41511, and 38530, Health and Safety Code.

§ 95131. Requirements for Verification Services.

Verification services shall be subject to the following requirements.

(a) *Notice of Verification Services.* After the Executive Officer has provided a determination that the potential for a conflict of interest is acceptable as specified in section 95133(f) and that verification services may proceed, the verification body shall submit a notice of verification services to ARB. The verification body may begin verification services for the reporting entity ten working days after the notice is received by the Executive Officer, or earlier if approved by the Executive Officer in writing. In the event that the conflict of interest statement and the notice of verification services are submitted together, verification services cannot begin until ten working days after the Executive Officer has deemed acceptable the potential for conflict of interest as specified in 95133(f). The notice shall include the following information:

(1) A list of the staff who will be designated to provide verification services as a verification team, including the names of each designated staff member, the lead verifier, and all subcontractors, and a description of the roles and responsibilities each member will have during verification. If any staff change on the verification team, that information must be updated and resubmitted to ARB five days before the verification services begin with the reporting entity;

(2) Documentation that the verification team has the skills required to provide verification services for the reporting facility. This shall include a demonstration that a verification team includes at least one member accredited to provide sector specific verification services when required below:

(A) For providing verification services to an electric power entity, a supplier of petroleum products or biofuels, a supplier of natural gas, natural gas liquids, or liquefied petroleum gas, or a supplier of carbon dioxide, at least one verification team member must be accredited by ARB as a transactions specialist;

(B) For providing verification services to the operator of a petroleum refinery, hydrogen production unit or facility, or petroleum and natural gas system listed in section 95101(e), at least one verification team member must be accredited by ARB as an oil and gas systems specialist;

(C) For providing verification services to the operator of a facility engaged in cement production, glass production, lime manufacturing, pulp and paper manufacturing, iron and steel production, or nitric acid production, at least one verification team member must be accredited by ARB as a process emissions specialist.

(3) General information on the reporting entity, including:

(A) The name of the reporting entity and the facilities and other locations that will be subject to verification services, reporting entity contact, address, telephone number, and e-mail address;
(B) The industry sector and the North American Industry Classification System (NAICS) code for the reporting facility;
(C) The date(s) of the on-site visit, with facility address and contact information;
(D) A brief description of expected verification services to be performed, including expected completion date.

(4) If any of the information under section 95131(a)(1) or 95131(a)(3) changes after the notice is submitted to ARB, the verification body must notify ARB at least five days before the verification services start date. If any information submitted under section 95131(a)(1) or 95131(a)(3) changes during the verification services, the verification body must notify ARB before the verification statement is provided to ARB.

(b) Verification services shall include, but are not limited to, the following:

(1) *Verification Plan.* The verification team shall obtain information from the reporting entity necessary to develop a verification plan. Such information shall include, but is not limited to:

(A) Information to allow the verification team to develop a general understanding of facility or entity boundaries, operations, emissions sources, and electricity or fuel transactions as applicable;
(B) Information regarding the training or qualifications of personnel involved in developing the emissions data report;
(C) Description of the specific methodologies used to quantify and report greenhouse gas emissions, electricity and fuel transactions, and associated data as needed to develop the verification plan;
(D) Information about the data management system used to track greenhouse gas emissions, electricity and fuel transactions, and associated data as needed to develop the verification plan.

(2) The verification team shall develop a verification plan that includes, at a minimum:

(A) Dates of proposed meetings and interviews with reporting facility personnel;
(B) Dates of proposed site visits;
(C) Types of proposed document and data reviews;
(D) Expected date for completing verification services.

(3) The verification team shall discuss with the reporting entity the scope of the verification services and request any information and documents needed for initial verification services. The verification team shall review the documents submitted and plan and conduct a review of original documents and supporting data for the emissions data report.

(4) *Site visits.* At least one accredited verifier in the verification team, including the sector specialist, if applicable, shall at a minimum make one site visit, during each year full verification is required, to each facility for which an emissions data report is submitted. The verification team member(s) shall visit the headquarters or other location of central data management when the reporting entity is a retail provider, marketer, or fuel supplier. During the site visit, the verification team member(s) shall conduct the following:

(A) The verification team member(s) shall check that all sources specified in sections 95110 to 95123, and 95150 to 95158, as applicable to the reporting entity are identified appropriately.

(B) The verification team member(s) shall review and understand the data management systems used by the reporting entity to track, quantify, and report greenhouse gas emissions and, when applicable, electricity and fuel transactions. The verification team member(s) shall evaluate the uncertainty and effectiveness of these systems.

(C) The verification team shall carry out tasks that, in the professional judgment of the team, are needed in the verification process, including the following:

1. Interviews with key personnel, such as process engineers and metering experts, as well as staff involved in compiling data and preparing the emissions data report;
2. Making direct observations of equipment for data sources and equipment supplying data for sources determined in the sampling plan to be high risk;
3. Assessing conformance with fuel analytical data requirements including: fuel meter accuracy requirements, data capture, and missing data substitution requirements;
4. Reviewing financial transactions to confirm fuel and electricity purchases and sales.

(5) The verification team shall review facility operations to identify applicable greenhouse gas emissions sources. This shall include a review of the emissions inventory and each type of emission source to ensure that all sources listed in sections 95110 to 95123 and sections 95150 to 95158 of this article are properly included in the emissions data report.

(6) Reporting entities shall make available to the verification team all information and documentation used to calculate and report emissions, fuels and electricity transactions, and other information required under this article, as applicable.

(7) For electricity importers and exporters, the verification team shall review electricity transaction records, including receipts of power attributed to the Northwest or Southwest region as verifiable via North American Electric Reliability Corporation (NERC) E-Tags, settlements data, or other information as confirmation of the region of origin.

(8) *Sampling Plan.* As part of confirming emissions data, electricity transactions, or fuel transactions the verification team shall develop a sampling plan that meets the following requirements:

(A) The verification team shall develop a sampling plan based on a strategic analysis developed from document reviews and interviews to assess the likely nature, scale and complexity of the verification services for a reporting entity. The analysis shall review the inputs for the development of the submitted emissions data report, the rigor and appropriateness of data management systems, and the coordination within the reporting entity's organization to manage the operation and maintenance of equipment and systems used to develop emissions data reports.

(B) The verification team shall include in the sampling plan a ranking of emissions sources by amount of contribution to total CO_2 equivalent emissions for the reporting entity, and a ranking of emissions sources with the largest calculation uncertainty. As applicable and deemed appropriate by the verification team, fuel and electricity transactions shall also be ranked or evaluated relative to the amount of fuel or power exchanged and uncertainties that may apply to data provided by the reporting entity.

(C) The verification team shall include in the sampling plan a qualitative narrative of uncertainty risk assessment in the following areas as applicable under sections 95110 to 95123, 95129, and 95150 to 95158:

1. Data acquisition equipment;
2. Data sampling and frequency;
3. Data processing and tracking;
4. Emissions calculations;
5. Data reporting;
6. Management policies or practices in developing emissions data reports.

(D) After completing the analyses required by sections 95131(b)(8)(A)-(C), the verification team shall include in the sampling plan a list which includes the following:

1. Emissions sources and/or transactions that will be targeted for document reviews, and data checks as specified in 95131(b)(9), and an explanation of why they were chosen;
2. Methods used to conduct data checks for each source or transaction;

3. A summary of the information analyzed in the data checks and document reviews conducted for each emissions source or transaction targeted.

The sampling plan list must be updated and finalized prior to the completion of verification services.

(E) The verification team shall revise the sampling plan to describe tasks completed by the verification team as relevant information becomes available and potential issues emerge with material misstatement or nonconformance with the requirements of this article.

(F) The verification body shall retain the sampling plan in paper, electronic, or other format for a period of not less than ten years following the submission of each verification statement. The sampling plan shall be made available to ARB upon request.

(G) The verification body shall retain all material received, reviewed, or generated to render a verification statement for a reporting entity for no less than ten years. The documentation must allow for a transparent review of how a verification body reached its conclusion in the verification statement.

(9) *Data Checks.* To determine the reliability of the submitted emissions data report, the verification team shall use data checks. Such data checks shall focus on the largest and most uncertain estimates of emissions and fuel and electricity transactions, and shall include the following:

(A) The verification team shall use data checks to ensure that the appropriate methodologies and emission factors have been applied for the emissions sources and fuel and electricity transactions covered under sections 95110 to 95123, 95129, and 95150 to 95158;

(B) The verification team shall choose for data checks emissions sources and fuel and electricity transactions data, as applicable, based on their relative contributions to emissions and the associated risks of contributing to material misstatement or nonconformance, as indicated in the sampling plan;

(C) The verification team shall use professional judgment in the number of data checks required for the team to conclude with reasonable assurance whether the total reporting entity reported emissions are free of material misstatement and the emissions data report otherwise conforms to the requirements of this article. At a minimum, data checks must include the following:

1. Tracing data in the emissions data report to its origin;
2. Looking at the process for data compilation and collection;
3. Recalculating emission estimates to check original calculations;

4. Reviewing calculation methodologies used by the reporting entity for conformance with this article; and
5. Reviewing meter and fuel analytical instrumentation measurement accuracy and calibration for consistency with the requirements of section 95103(k).

The verification team shall compare its own calculated results with the reported data in order to confirm the extent and impact of any omissions and errors. Any discrepancies must be investigated. The comparison of data checks must provide enough detail to indicate which sources and transactions were checked, the types and quantity of data that were evaluated for each source and transaction, and any discrepancies that were identified.

(10) *Emissions Data Report Modifications.* As a result of data checks by the verification team and prior to completion of a verification statement, the reporting entity must make any possible improvements or corrections to the submitted emissions data report, and submit a revised emissions data report to ARB. The reporting entity shall maintain documentation to support any revisions made to the initial emissions data report. Documentation for all emissions data report submittals shall be retained by the reporting entity for ten years pursuant to section 95105.

(11) *Findings.* To verify that the emissions data report is free of material misstatement, the verification team shall make its own determination of emissions for checked sources and shall determine whether there is reasonable assurance that the emissions data report does not contain a material misstatement for the reporting entity, on a CO_2 equivalent basis for GHG emissions. To assess conformance with this article the verification team shall review the methods and factors used to develop the emissions data report for adherence to the requirements of this article and ensure that other requirements of this article are met.

(12) *Log of Issues.* The verification team must keep a log of any issues identified in the course of verification activities that may affect determinations of material misstatement and nonconformance. The issues log must identify the regulatory section related to the nonconformance, if applicable, and indicate if the issues were corrected by the reporting entity prior to completing the verification. Any other concerns that the verification team has with the preparation of the emissions data report, including with any *de minimis* method calculations, must be documented in the issues log. The log of issues must indicate whether each issue has a potential bearing on material misstatement, nonconformance, or both.

(13) An assessment of material misstatement is conducted on total reported GHG emissions (metric tons of CO_2e), except those emissions without a compliance obligation as set forth in title 17, California Code of Regulations, section 95852.2.

(14) In assessing whether an emissions data report contains a material misstatement, the verification team must determine whether the total reported emissions contain a material misstatement using the following equation:

$$Percent\ accuracy = 100\% - \sum \frac{[Errors + Omissions + Misreporting]\ x\ 100\%}{Total\ reported\ emissions}$$

Where:
"Errors" means any differences between the reported emissions and verifier calculated emissions for a data source subject to data checks in 95131(b)(9).

"Omissions" means any emissions the verifier concludes must be part of the emissions data report, but were not included by the reporting entity in the emissions data report.

"Misreporting" means duplicate, incomplete or other emissions the verifier concludes should, or should not, be part of the emissions data report.

"Total reported emissions" means the total annual reporting entity CO2e emissions reported for the emission sources which hold a compliance obligation as set forth in title 17, California Code of Regulations, sections 95852 and 95852.1 for which the verifier is conducting a material misstatement assessment.

(15) The verification team must check the following for conformance as part of verifier review with the reporting requirements under this article, when applicable data checks are chosen under 95131(b)(9), but does not have to conduct a material misstatement assessment using the equation in 95131(b)(14);

(A) Total reported facility indirect electricity purchases (kWH);
(B) Total reported facility indirect thermal purchases (Btu);
(C) Total reported GHG emissions (metric tons of CO_2e) included in the emissions data report as emissions without a compliance obligation under title 17, California Code of Regulations, section 95852.2.

(16) *Review of Missing Data Substitution.* If a source selected for a data check was affected by a loss of data used to calculate GHG emissions for the data year:

(A) The verification team shall confirm that the reported emissions for that source were calculated using the applicable missing data procedures, or that an approved interim data collection procedure was used for the source.

(B) The difference between the reporting entity's calculated emissions and verifier's calculated emissions for that source will be zero when assessing for material misstatement under section 95131(b)(14), when the applicable missing data substitution procedures or interim data collection procedure has been correctly applied by the reporting entity; or, any relative accuracy assigned to the emissions estimate under section 95129(h)(4) has been correctly applied.

(C) If 20 percent or less of any combination of data elements used to measure emissions from fuel or direct measurement are missing, and emissions correctly calculated using the missing data requirements in sections 95110 to 95123, 95129, and 95150 to 95158 will be considered accurate and as meeting the reporting requirements for that source.

(D) If greater than 20 percent of the emissions for a source has been calculated from data that has been substituted according to the missing data provisions of this article, the verifier will note a non-conformance as part of the verification finding.

(c) Completion of verification services must include:

(1) *Verification Statement.* Upon completion of the verification services specified in section 95131(b), the verification body shall complete a verification statement, and provide that statement to the reporting entity and the ARB by the applicable verification deadline specified in section 95103(f). Before that statement is completed, the verification body shall have the verification services and findings of the verification team independently reviewed within the verification body by an independent reviewer who is a lead verifier not involved in services for that reporting entity during that year.

(2) The independent reviewer shall serve as a final check on the verification team's work to identify any significant concerns, including:

(A) errors in planning,
(B) errors in data sampling, and
(C) errors in judgment by the verification team that are related to the draft verification statement.

The independent reviewer must maintain independence from the verification services by not making specific recommendations about how the verification services should be conducted. The independent reviewer will review documents relevant to the verification services provided, and identify any failure to comply with requirements of this article or with the verification body's internal policies and procedures for providing verification services. The independent reviewer must concur with the verification findings before the verification statement can be issued.

(3) When the verification team completes its findings:

(A) The verification body shall provide to the reporting entity a detailed verification report. The detailed verification report shall at a minimum include the verification plan, the detailed comparison of the data checks conducted during verification services, the log of issues identified in the course of verification activities and their resolution, and any qualifying comments on findings during verification services. The detailed verification report shall also include the calculation performed in section 95131(b)(14). The detailed verification report shall be made available to ARB upon request.

(B) The verification team shall have a final discussion with the reporting entity explaining its findings, and notify the reporting entity of any unresolved issues noted in the issues log before the verification statement is finalized.

(C) The verification body shall provide the verification statement to the reporting entity and the ARB, attesting whether the verification body has found the submitted emissions data report to be free of material misstatement, and whether the emissions data report is in conformance with the requirements of this article. In the case of a qualified positive verification statement, the verification body shall explain the non-conformances contained within the emissions data report and why the non-conformances do not result in a material misstatement. In the case of an adverse verification statement, the verification body must explain all non-conformances and material misstatements leading to the adverse verification statement.

(D) The lead verifier in the verification team shall attest that the verification team has carried out all verification services as required by this article, and the lead verifier who has conducted the independent review of verification services and findings shall attest to his or her independent review on behalf of the verification body and his or her concurrence with the verification findings.

(4) Prior to the verification body providing an adverse verification statement to the ARB, the reporting entity shall be provided at least ten working days to modify the emissions data report to correct any material misstatement or nonconformance found by the verification team. The modified report and verification statement must be submitted to ARB before the applicable verification deadline, unless the reporting entity makes a request to the Executive Officer as provided below in section 95131(c)(4)(A).

(A) If the reporting entity and the verification body cannot reach agreement on modifications to the emissions data report that result in a positive verification statement or qualified positive verification statement because of a disagreement on the requirements of this article, the reporting entity may petition the ARB Executive Officer to make a final decision as to the verifiability of the submitted emissions data report.

(B) If the Executive Officer determines that the emissions data report does not meet the standards and requirements specified in this article, the reporting entity shall have the opportunity to submit within thirty days of the date of this decision any emissions data report revisions that address the Executive Officer's determination, for re-verification of the emissions data report. In re-verifying a revised emissions data report, the verification body and verification team shall be subject to the requirements in section 95131(c)(1)-(3), and must submit the revised verification statement to ARB within 15 days.

(5) *Assigned Emissions Level.* When a reporting entity fails to receive a positive or qualified positive verification statement for a data year by the applicable deadline, the Executive Officer shall develop an assigned emissions level for the data year for the reporting entity. Within ten days of a written request by the Executive Officer, the verification body (if applicable) shall provide any available verification services information or correspondence related to the emissions data. Within ten days of a request by the Executive Officer, the reporting entity shall provide the data that is required to calculate GHG emissions for the entity according to the requirements of this article, the preliminary or final detailed verification report prepared by the verification body (if applicable), and other information requested by the Executive Officer, including the operating days and hours of the reporting entity during the data year. The reporting entity shall also make available personnel who can assist the Executive Officer's determination of an assigned emissions level for the data year.

(A) In preparing the assigned emissions level for the reporting entity, the Executive Office shall consider at a minimum the following information:

1. The number, types and days and hours of operation of the sources operated by the reporting entity for the emissions data year;
2. Any previous emissions data reports submitted by the reporting entity and verification statements rendered for those reports;
3. The potential maximum fuel and process material input and output capacities for the reporting entity's emissions sources during operating hours;
4. For electric power entities, wholesale and retail transactions that would affect an assigned emissions level, for the relevant data year and for previous years;
5. Emissions, electricity transactions, fuel use, or product output information reported to ARB or other State, federal, or local agencies.

(B) The Executive Officer shall calculate the assigned emissions level for the reporting entity using the best information available, including the information in section 95131(c)(5)(A), as applicable. The reporting entity

shall be provided at least 5 days to review and comment on the assigned emissions level.

(d) Upon provision of the verification statement to ARB, the emissions data report shall be considered final. No changes shall be made to the report as submitted to ARB, notwithstanding the requirements of 40 CFR §98.3(h), and all verification requirements of this article shall be considered complete except in the circumstance specified in section 95131(e).

(e) If the Executive Officer finds a high level of conflict of interest existed between a verification body and a reporting entity, or an emissions data report that received a positive or qualified positive verification statement fails an ARB audit, the Executive Officer may set aside the positive or qualified positive verification statement issued by the verification body, and require the reporting entity to have the emissions data report re-verified by a different verification body within 90 days.

(f) Upon request by the Executive Officer the reporting entity shall provide the data used to generate an emissions data report, including all data available to a verifier in the conduct of verification services, within 10 working days.

(g) Upon request of the Executive Officer the verification body shall provide ARB the full verification report given to the reporting entity, as well as the sampling plan and any other supporting documents and calculations, within 10 working days.

(h) Upon written notification by the Executive Officer, the verification body shall make its personnel available for an ARB audit.

(i) *Verifying Biomass-derived Fuels.* Requirements for providing verification services for biomass-derived fuels not subject to a compliance obligation as set forth in title 17, California Code of Regulations, Section 95852.2 In the absence of certification of the fuel by an accredited certifier of biomass-derived fuels, the verification body shall conduct the following requirements to verify a biomass-derived fuel that will not be subject to a compliance obligation:

(1) The verification body shall provide information assessing its potential for conflict of interest as set forth in section 95133(b),(c) and (d) with the reporting entity and each biomass-derived fuel entity in the chain of custody for that fuel as part of the conflict of interest submittal requirements in 95133(e)

(2) At least one accredited verifier in the verification team, including the transactions sector specialist, shall at a minimum make one site visit, during each year full verification is required, to each biomass-derived fuel entity in the chain of custody for that fuel. One member of the verification team must visit the headquarters or other location of central data management when the biomass-derived fuel entity is a marketer, distributor, or suppler and does not physically store or produce the fuel on-site and conduct the site visit as

required in section 95131(b)(4) for each biomass-derived fuel entity in the chain of custody for that fuel.

(A) The verification team members shall examine biomass-derived fuel contracts to determine that one of the two following conditions has been met:

1. That the contract for purchasing any biomass-derived fuel was in effect prior to January 1, 2010 and remains in effect or has been renegotiated for the same California operator within one year of contract expiration;
2. That the fuel being provided under a contract dated after January 1, 2010 is only for an amount of fuel that is associated with an increase in the biomass-based fuel producer's capacity.

If a contract includes both fuel that does and does not meet this condition, then only the portion of the fuel that does meet this condition will be considered biomass-derived fuel.

(B) The verification team shall determine that no entity in the chain of custody has applied for or received credit for the use of biomass-derived fuel in offset credits or any other credit for greenhouse gas reductions in another voluntary or regulatory project.

(C) The verification team shall determine that any entity that produces biomass-derived fuels is doing so in accordance with the requirements of title 17, California Code of Regulations, section 95852.2.

(D) The verification team shall determine that an entity's total volume of biomass-derived fuel transferred to all customers in a calendar year does not exceed the entity's purchases and production of biomass-derived fuels during that year.

(E) The verification team must be able to track the exact amount of fuel indentified in contracts or invoices from the producer to the reporting entity, and have reasonable assurance that the reporting entity is the only customer receiving that fuel.

(F) The verification team shall review and evaluate all fuel analytical devices and data management systems used by biomass-derived fuel entities to quantify, track, and report fuel amounts. The verification team must evaluate the uncertainty and effectiveness of these systems using the requirements in section 95131(b)(8).

(G) Verifying fuel transactions shall include evaluating the measured and estimated fuel volumes, as well as any relevant information required to calculate emissions including composition, high heat value, carbon content, or supplier specific emission factors.

(3) If any biomass-derived fuel entity in the chain of custody does not make available to the verification team all the information and documentation

necessary to establish the validity of the reporting entity's claim of biomass-derived fuel purchase, the fuel purchase, as described in section 95131(i)(2)(B-G), will be considered unverifiable and be required to hold a compliance obligation under title 17, California Code of Regulations, section 95852.1.

(4) To verify that the amount of biomass-derived fuel reported by a reporting entity is free of a material misstatement, the verification team shall determine whether there is reasonable assurance that the amount of biomass derived fuel purchased was actually produced and delivered, or injected into a transmission pipeline to the reporting entity, and any errors, omissions, or misreporting of the biofuels emissions do not result in a material misstatement. To assess conformance with this article, the verification team shall review the methods and factors used to calculate and report biomass-derived fuel amounts for adherence to the requirements of this article.

(5) Verification requirements specific to biomass-derived fuel producing facilities are as follows:

(A) The verification team shall establish that the biomass-derived fuel entity employs procedures for fuel data measurement with an accuracy within ±5 percent. All fuel analytical measurement devices shall be installed, maintained and calibrated in a manner and at a frequency required to maintain this level of accuracy. If the documentation to support this level of accuracy is not provided to the verification team, then the fuel will be considered unverifiable and be required to hold a compliance obligation under title 17, California Code of Regulations, section 95852.1.

(B) The verification team shall establish that the heating value of the biomass-derived fuel used in any transaction was appropriately calculated using the method required by section 95115(c).

(C) The verification team shall establish that the biomass-derived fuel entity retains at least 95% of its fuel production or fuel transaction data. If more than 5% of data is missing, the fuel will be considered unverifiable and be required to hold a compliance obligation under title 17, California Code of Regulations, section 95852(g).

(6) If the verification body is unable to verify the biomass-based fuel to the above requirement, it will be considered unverifiable and be required to hold a compliance obligation under title 17, California Code of Regulations, section 95852.1.

NOTE: Authority cited: Sections 39600, 39601, 39607, 39607.4, 41511, 38510, and 38530, Health and Safety Code. Reference: Sections 39600, 41511, and 38530, Health and Safety Code.

§ 95132. Accreditation Requirements for Verification Bodies, Lead Verifiers, and Verifiers of Emissions Data Reports and Offset Project Data Reports.

(a) The accreditation requirements specified in this subarticle shall apply to all verification bodies, lead verifiers, and verifiers that wish to provide verification services under this article and under the Cap-and-Trade Regulation.

(b) The Executive Officer may issue accreditation to verification bodies, lead verifiers, and verifiers that meet the requirements specified in this section.

(1) *Verification Body Accreditation Application.* To apply for accreditation as a verification body, the applicant shall submit the following information to the Executive Officer:

(A) A list of all verification staff and a description of their duties and qualifications, including ARB accredited verifiers on staff. The applicant shall demonstrate staff qualifications by listing each individual's education, experience, professional licenses, and other pertinent information.

1. A verification body shall have and retain at least two verifiers that have been accredited as lead verifiers, as specified in section 95132(b)(2);
2. A verification body shall have and retain at least five total full-time staff.

(B) The applicant shall provide a list of any judicial proceedings or administrative actions filed against the body within the previous 5 years, with an explanation as to the nature of the proceedings.

(C) The applicant shall provide documentation that the proposed verification body maintains a minimum of four million U.S. dollars of professional liability insurance and must maintain this insurance for three years after completing verification services.

(D) The applicant shall provide a demonstration that the body has policies and mechanisms in place to prevent conflicts of interest and to identify and resolve potential conflict of interest situations if they arise. The applicant shall provide the following information:

1. Identification of services provided by the verification body, the industries that the body serves, and the locations where those services are provided;
2. A detailed organizational chart that includes the verification body, its management structure, and any related entities;

3. The verification body's internal conflict of interest policy that identifies activities and limits to monetary or non-monetary gifts that apply to all employees.

(E) The applicant shall provide a demonstration that the body has procedures or policies to support staff technical training as it relates to verification. This training shall include participating in ARB verifier training on an ongoing basis.

(F) The verification body shall notify ARB within 30 days of when it no longer meets the requirements for accreditation as a verification body in section 95132(b)(1). The verification body may request that the Executive Officer provide an additional time to hire additional staff to meet the minimum requirements of this section.

(G) If the applicant is a California air pollution control district or air quality management district, the requirements of section 95132(b)(1)(A)(2) and 95132(b)(1)(B)-(D) do not apply, except that the applicant shall provide a demonstration that the district has policies and mechanisms in place to prevent conflicts of interest and resolve potential conflict of interest situations if they arise.

(2) *Lead Verifier Accreditation Application.* To apply for accreditation as a lead verifier, the applicant shall submit documentation to the Executive Officer that provides the evidence specified in section 95132(b)(2)(A), and section 95132(b)(2)(B), or (C):

(A) Evidence that the applicant meets the criteria in 95132(b)(3); and,
(B) Evidence that the applicant has been an ARB accredited verifier for two continuous years and has worked as a verifier in at least three completed verifications under the supervision of an ARB accredited lead verifier, with evidence of favorable assessment by ARB for services performed; or,
(C) Evidence that at the time of the verification training examination, the applicant has worked as a project manager or lead person for not less than four years, of which two may be graduate level work:

1. In the development of GHG or other air emissions inventories; or,
2. As a lead environmental data or financial auditor in the private sector.

(3) *Verifier Accreditation Application.* To apply for accreditation as a verifier, the applicant shall submit the following documentation to the Executive Officer:

(A) Evidence demonstrating the minimum education background required to act as a verifier for ARB. Minimum education background means that the applicant has either:

1. A bachelors level college degree or equivalent in science, technology, business, statistics, mathematics, environmental policy, economics, or financial auditing; or
2. Evidence demonstrating the completion of significant and relevant work experience or other personal development activities that have provided the applicant with the communication, technical and analytical skills necessary to conduct verification.

(B) Evidence demonstrating sufficient workplace experience to act as a verifier, including evidence that the applicant has a minimum of two years of fulltime work experience in a professional role involved in emissions data management, emissions technology, emissions inventories, environmental auditing, or other technical skills necessary to conduct verification.

(4) The applicant must take an ARB approved general verification training course and receive a passing score of greater than an unweighted 70% on an exit examination. If the applicant does not pass the exam after the training, they may retake the exam a second time. Only one retake of the examination is allowed before the applicant is required to retake the ARB approved general verification training course. Training under the previous version of the regulation does not qualify an applicant to retake an exam under this version without first taking the training class for this revised regulation.

(5) Sector Specific and Offset Project Specific Verifiers.

(A) The applicant seeking to be accredited as a sector specific verifier as specified in section 95131(a)(2) must, in addition to meeting the requirements for lead verifier or verifier qualification, have at least two years of professional experience related to the sector in which they are seeking accreditation, take ARB sector specific verification training and receive a passing score of greater than an unweighted 70% on an exit examination. If the applicant does not pass the exam after the training, they may retake the exam a second time. Only one retake of the examination is allowed before the applicant is required to retake the ARB approved general verification training course.

(B) The applicant seeking to be accredited as an offset project specific verifier as specified in title 17, California Code of Regulations, section 95977(e)(4)(A)(iii), in addition to meeting the requirements for verifier qualification, shall meet the following requirements:

1. Be a verifier in good standing for the Climate Action Reserve prior to November 1, 2010 and have performed at least two project verifications for a project type by December 31, 2010; or
2. Have at least two years of professional experience related to developing emission inventories, conducting technical analyses, or environmental audits of the offset project type; and
3. Take ARB offset project verification training for an offset project type and receive a passing score of greater than an unweighted 70% on an exit examination. If the applicant does not pass the exam after the training, they may retake the exam a second time. Only one retake of the examination is allowed before the applicant is required to retake the ARB approved general verification training course.

(6) Nothing in this section shall be construed as preventing the Executive Officer from requesting additional information or documentation from an applicant after receipt of the application for accreditation as a verification body, lead verifier, or verifier, or from seeking additional information from other persons or entities regarding the applicant's fitness for qualification.

(c) *ARB Accreditation.*

(1) Within 90 days of receiving an application for accreditation as a verification body, lead verifier, or verifier, the Executive Officer shall inform the applicant in writing either that the application is complete or that additional specific information is required to make the application complete.
(2) Upon a finding by the Executive Officer that an application for accreditation as a verifier or lead verifier is complete and meets all applicable regulatory requirements, the prescreening requirement is met and the applicant will be eligible to attend the verification training required by this section.
(3) Within 45 days following completion of the application process and all applicable training and examination requirements, the Executive Officer shall act to issue an Executive Order to grant or withhold accreditation for the verification body, lead verifier, or verifier.
(4) The Executive Order for accreditation is valid for a period of three years, whereupon the applicant may re-apply for accreditation as a verifier, lead verifier, or verification body if the applicant has not been subject to ARB enforcement action under this article. All ARB approved general, sector specific, or offset project specific verification training and examination requirements applicable at the time of re-application must be met for accreditation to be renewed by the Executive Officer. The following requirements also apply at the time of application for re-accreditation as a lead verifier, verifier, sector specific verifier, or offset project verifier:

(A) If the applicant has not participated in at least one ARB verification by January 1, 2012, the applicant must take ARB approved GHG verification training that includes general verifier training and receive a

passing score of greater than an unweighted 70% on the exit examination.

(B) If the applicant has participated in at least one ARB verification by January 1, 2012, then the applicant must take ARB approved abbreviated training that includes changes to the program since the original training was provided under 95132(b)(4), 95132(b)(5)(A), and 95132(b)(5)(B)3, and receive a passing score of greater than an unweighted 70% on the exit examination. This examination shall cover general verification and the training.

(5) All verification body requirements in section 95132(b)(1) must be met for the Executive Officer to renew the verification body accreditation.

(6) The Executive Officer and the applicant may mutually agree to longer time periods than those specified in subsections 95132(c)(1) or 95132(c)(3), and the applicant may submit additional supporting documentation before a decision has been made by the Executive Officer.

(7) Within 15 working days of being notified of any corrective action in another voluntary or mandatory GHG program, an ARB accredited verification body or verifier shall provide written notice to the Executive Officer of the corrective action. That notification shall include reasons for the corrective action and the type of corrective action. The verification body or verifier must provide additional information to the Executive Officer upon request.

(8) Verifiers accredited by ARB prior to January 1, 2011 shall take ARB approved training to continue to provide verification services after January 1, 2012. The training will focus on changes to the program since the original training was provided under 95132(b)(4) and 95132(b)(5)(A). The verifier must receive a passing score of greater than an unweighted 70% on the exit examination.

(d) *Modification, Suspension, or Revocation of an Executive Order Approving a Verification Body, Lead Verifier, or Verifier.* The Executive Officer may review and, for good cause, including any violation of subarticle 4 of this article or any similar action in an analogous GHG system, modify, suspend, or revoke an Executive Order providing accreditation to a verification body, lead verifier, or verifier. The Executive Officer shall not revoke an Executive Order without affording the verification body, lead verifier, or verifier the opportunity for a hearing in accordance with the procedures specified in title 17, California Code of Regulations, section 60055.1 et seq.

(1) During suspension or revocation proceedings, the verification body, lead verifier, or verifier may not continue to provide verification services.

(2) Within 5 working days of suspension or revocation of accreditation, a verification body must notify all reporting entities, offset project operators, or authorized project designees for whom it is providing verification services, or has provided verification services within the past 6 months of its suspension or revocation of accreditation.

(3) A reporting entity, offset project operator, or authorized project designee who has been notified by a verification body of a suspended or revoked accreditation must contract with a new verification body for verification services.

(e) *Subcontracting.* The following requirements shall apply to any verification body that elects to subcontract a portion of verification services.

(1) All subcontractors must be accredited by ARB to perform the verification services for which the subcontractor has been engaged by the verification body.
(2) The verification body must assume full responsibility for verification services performed by subcontractor verifiers.
(3) A verification body shall not use subcontractors to meet the minimum staff total or lead verifier requirements as specified in section 95132(b)(1)(A)1. and section 95132(b)(1)(A)2.
(4) A verifier acting as a subcontractor to another verification body shall not further subcontract or outsource verification services for a reporting entity.
(5) A verification body that engages a subcontractor shall be responsible for demonstrating an acceptable level of conflict of interest, as provided in section 95133, between its subcontractor and the reporting entity for which it will provide verification services.
(6) A verification body may not use a subcontractor as the independent reviewer.

NOTE: Authority cited: Sections 39600, 39601, 39607, 39607.4, 41511, 38510, and 38530, Health and Safety Code. Reference: Sections 39600, 41511, and 38530, Health and Safety Code.

§ 95133. Conflict of Interest Requirements for Verification Bodies for Emissions Data Reports.

(a) The conflict of interest provisions of this section shall apply to verification bodies, lead verifiers, and verifiers accredited by ARB to perform verification services for reporting entities.

(b) The potential for a conflict of interest must be deemed to be high where:

(1) The verification body and reporting entity share any management staff or board of directors membership, or any of the senior management staff of the reporting entity have been employed by the verification body, or vice versa, within the previous three years; or
(2) Within the previous five years, any staff member of the verification body or any related entity has provided to the reporting entity any of the following non-verification services:

(A) Designing, developing, implementing, reviewing, or maintaining an inventory or information or data management system for facility air emissions, or, where applicable, electricity or fuel transactions, unless the review was part of providing greenhouse gas verification services;
(B) Developing greenhouse gas emission factors or other greenhouse gas-related engineering analysis, including developing or reviewing a California Environmental Quality Act (CEQA) greenhouse gas analysis that includes facility specific information;
(C) Designing energy efficiency, renewable power, or other projects which explicitly identify greenhouse gas reductions as a benefit;
(D) Designing, developing, implementing, conducting an internal audit, consulting, or maintaining a GHG emissions reduction or GHG removal offset project as defined in the Cap-and-Trade Regulation;
(E) Owning, buying, selling, trading, or retiring shares, stocks, or emissions reduction credits from an offset project that was developed by or resulting reduction credits are owned by the reporting entity;
(F) Dealing in or being a promoter of credits on behalf of an offset project operator or authorized project designee where the credits are owned by or the offset project was developed by the reporting entity;
(G) Preparing or producing greenhouse gas-related manuals, handbooks, or procedures specifically for the reporting entity;
(H) Appraisal services of carbon or greenhouse gas liabilities or assets;
(I) Brokering in, advising on, or assisting in any way in carbon or greenhouse gas-related markets;
(J) Directly managing any health, environment or safety functions for the reporting entity;
(K) Bookkeeping or other services related to accounting records or financial statements;
(L) Any service related to information systems, including ISO 14001 certification, unless those systems will not be part of the verification process;
(M) Appraisal and valuation services, both tangible and intangible;
(N) Fairness opinions and contribution-in-kind reports in which the verification body has provided its opinion on the adequacy of consideration in a transaction, unless the resulting services will not be part of the verification process;
(O) Any actuarially oriented advisory service involving the determination of amounts recorded in financial statements and related accounts;
(P) Any internal audit service that has been outsourced by the reporting entity or offset project operator that relates to the reporting entity's internal accounting controls, financial systems or financial statements, unless the result of those services will not be part of the verification process;
(Q) Acting as a broker-dealer (registered or unregistered), promoter or underwriter on behalf of the reporting entity;
(R) Any legal services;

(S) Expert services to the reporting entity or a legal representative for the purpose of advocating the reporting entity's interests in litigation or in a regulatory or administrative proceeding or investigation.

"Member" for the purposes of this section means any employee or subcontractor of the verification body or related entities of the verification body. "Member" also includes any individual with majority equity share in the verification body or its related entities. "Related entity" for the purposes of this section means any direct parent company, direct subsidiary, or sister company.

(3) The potential for conflict of interest shall be deemed to be high when any staff member of the verification body provides any type of non-monetary incentive to a reporting entity to secure a verification services contract.

(4) The potential for a conflict of interest shall also be deemed to be high where any staff member of the verification body has provided verification services for the reporting entity except within the time periods in which the reporting entity is allowed to use the same verification body as specified in sections 95130(a).

(c) The potential for a conflict of interest shall be deemed to be low where no potential for a conflict of interest is found under section 95133(b) and any non-verification services provided by any member of the verification body to the reporting entity within the last three years are valued at less than 20 percent of the fee for the proposed verification.

(d) The potential for a conflict of interest shall be deemed to be medium where the potential for a conflict of interest is not deemed to be either high or low as specified in sections 95133(b) and 95133(c). The potential for conflict of interest will also be deemed to be medium where there are any instances of personal or familial relationships between the members of the verification body and management or staff of the reporting entity.

(1) If a verification body identifies a medium potential for conflict of interest and intends to provide verification services for the reporting entity, the verification body shall submit, in addition to the submittal requirements specified in section 95133(e), a plan to avoid, neutralize, or mitigate the potential conflict of interest situation. At a minimum, the conflict of interest mitigation plan shall include:

(A) A demonstration that any individuals with potential conflicts have been removed and insulated from the project.

(B) An explanation of any changes to the organizational structure or verification body to remove the potential conflict of interest. A demonstration that any unit with potential conflicts has been divested or moved into an independent entity or any subcontractor with potential conflicts has been removed.

(C) Any other circumstance that specifically addresses other sources for potential conflict of interest.

(2) As provided in section 95133(f)(4), the Executive Officer shall evaluate the conflict of interest mitigation plan and determine whether verification services may proceed.

(e) *Conflict of Interest Submittal Requirements for Accredited Verification Bodies.*

(1) Before the start of any work related to providing verification services to a reporting entity, a verification body must first be authorized in writing by the Executive Officer to provide verification services. To obtain authorization the verification body shall submit to the Executive Officer a self-evaluation of the potential for any conflict of interest that the body, its partners, or any subcontractors performing verification services may have with the reporting entity for which it will perform verification services. The submittal shall include the following:

(A) Identification of whether the potential for conflict of interest is high, low, or medium based on factors specified in sections 95133(b), (c), and (d);
(B) Identification of whether the verification body or any member of the verification team has previously provided verification services for the reporting entity and, if so, the years in which such verification services were provided;
(C) Identification of whether any member of the verification team or related entity has engaged in any non-verification services of any nature with the reporting entity either within or outside California during the previous three years. If non-verification services have previously been provided, the following information shall also be submitted:

1. Identification of the nature and location of the work performed for the reporting entity and whether the work is similar to the type of work to be performed during verification, such as emissions inventory, auditing, energy efficiency, renewable energy, or other work with implications for the reporting entity's greenhouse gas emissions or the accounting of greenhouse gas emissions or electricity or fuel transactions;
2. The nature of past, present or future relationships with the reporting entity including:

a. Instances when any member of the verification team has performed or intends to perform work for the reporting entity;
b. Identification of whether work is currently being performed for the reporting entity, and if so, the nature of the work;
c. How much work was performed for the reporting entity in the last three years, in dollars;

d. Whether any member of the verification team has any contracts or other arrangements to perform work for the reporting entity or a related entity;
e. How much work related to greenhouse gases or electricity transactions the verification team has performed for the reporting entity or related entities in the last three years, in dollars.

3. Explanation of how the amount and nature of work previously performed is such that any member of the verification team's credibility and lack of bias should not be under question.

(D) A list of names of the staff that would perform verification services for the reporting entity, and a description of any instances of personal or family relationships with management or employees of the reporting entity that potentially represent a conflict of interest; and,
(E) Identification of any other circumstances known to the verification body, or reporting entity that could result in a conflict of interest.
(F) Attest, in writing, to ARB as follows:

"I certify under penalty of perjury of the laws of California the information provided in the Conflict of Interest submittal is true, accurate, and complete."

(f) *Conflict of Interest Determinations.* The Executive Officer must review the self-evaluation submitted by the verification body and determine whether the verification body is authorized to perform verification services for the reporting entity.

(1) The Executive Officer shall notify the verification body in writing when the conflict of interest evaluation information submitted under section 95132(e) is deemed complete. Within 30 working days of deeming the information complete, the Executive Officer shall determine whether the verification body is authorized to proceed with verification and must so notify the verification body.
(2) If the Executive Officer determines the verification body or any member of the verification team meets the criteria specified in section 95133(b), the Executive Officer shall find a high potential conflict of interest and verification services may not proceed.
(3) If the Executive Officer determines that there is a low potential conflict of interest, verification services may proceed.
(4) If the Executive Officer determines that the verification body and verification team have a medium potential for a conflict of interest, the Executive Officer shall evaluate the conflict of interest mitigation plan submitted pursuant to sections 95133(d), and may request additional information from the applicant to complete the determination. In determining whether verification services may proceed, the Executive Officer may consider factors including, but not limited to, the nature of previous work performed, the current and past

relationships between the verification body and its subcontractors with the reporting entity, and the cost of the verification services to be performed. If the Executive Officer determines that these factors when considered in combination demonstrate an acceptable level of potential conflict of interest, the Executive Officer will authorize the verification body to provide verification services.

(g) *Monitoring Conflict of Interest Situations.*

(1) After commencement of verification services, the verification body shall monitor and immediately make full disclosure in writing to the Executive Officer regarding any potential for a conflict of interest situation that arises. This disclosure shall include a description of actions that the verification body has taken or proposes to take to avoid, neutralize, or mitigate the potential for a conflict of interest.

(2) The verification body shall continue to monitor arrangements or relationships that may be present for a period of one year after the completion of verification services. During that period, within 30 days of the verification body or any verification team member entering into any contract with the reporting entity for which the body has provided verification services, the verification body shall notify the Executive Officer of the contract and the nature of the work to be performed. The Executive Officer, within 30 working days, will determine the level or conflict using the criteria in section 95133(a)-(d), if the reporting entity must reverify their emissions data report, and if accreditation revocation is warranted.

(3) The verification body shall notify the Executive Office, within 30 days, of any emerging conflicts of interest during the time verification services are being provided.

(A) If the Executive Officer determines that a disclosed emerging potential conflict is medium risk and this risk can be mitigated, the verification body is deemed to have met the conflict of interest requirements to continue to provide verification services to the reporting entity and will not be subject to suspension or revocation of accreditation as specified in section 95132(d).

(B) If the Executive Officer determines that a disclosed emerging potential conflict is medium or high risk and this risk cannot be mitigated, the verification body will not be able to continue to provide verification services to the reporting entity, and may be subject to suspension or revocation of accreditation under section 95132(d).

(4) The verification body shall report to the Executive Officer any changes in its organizational structure, including mergers, acquisitions, or divestitures, for one year after completion of verification services.

(5) The Executive Officer may invalidate a verification finding if a potential conflict of interest has arisen for any member of the verification team. In such a case, the reporting entity shall be provided 90 days to complete re-verification.
(6) If the verification body or its subcontractor(s) are found to have violated the conflict of interest requirements of this article, the Executive Officer may rescind accreditation of the body, its verifier staff, or its subcontractor(s) as provided in section 95132(d).

NOTE: Authority cited: Sections 39600, 39601, 39607. 39607.4, 41511, 38510, and 38530, Health and Safety Code. Reference: Sections 39600, 41511, and 38530, Health and Safety Code.

Subarticle 5. Reporting Requirements and Calculation Methods for Petroleum and Natural Gas Systems.

§ 95150. Definition of the Source Category.

(a) This source category consists of the following:

(1) *Offshore petroleum and natural gas production.* Offshore petroleum and natural gas production is any platform structure, affixed temporarily or permanently to offshore submerged lands, that houses equipment to extract hydrocarbons from the ocean or lake floor and that transfers such hydrocarbons to storage, transport vessels, or onshore. In addition, offshore production includes secondary platform structures and storage tanks associated with the platform structure.

(2) *Onshore petroleum and natural gas production.* Onshore petroleum and natural gas production equipment means all structures associated with wells (including compressors, generators, or storage facilities), piping (including flowlines or intra-facility gathering lines), and portable non-self-propelled equipment (including well drilling and completion equipment, workover equipment, gravity separation equipment, auxiliary non-transportation-related equipment, and leased, rented or contracted equipment) used in the production, extraction, recovery, lifting, stabilization, separation or treating of petroleum and/or natural gas (including condensate). This also includes associated storage or measurement and all systems engaged in gathering produced gas from multiple wells, all enhanced oil recovery (EOR) operations using CO_2 and thermal energy, and all petroleum and natural gas production located on islands, artificial islands or structures connected by a causeway to land, an island, or artificial island.

(3) *Onshore natural gas processing plants.* Natural gas processing plants are designed to separate and recover natural gas liquids (NGLs) or other non-methane gases and liquids from a stream of produced natural gas to meet onshore natural gas transmission pipeline quality specifications through equipment performing one or more of the following processes: oil and condensate removal, water removal, separation of natural gas liquids, sulfur and carbon dioxide removal, fractionation of NGLs, or other processes, and also the capture of CO_2 separated from natural gas streams for delivery outside the facility. In addition, field gathering and/or boosting stations that gather and process natural gas from multiple wellheads, and compress and transport natural gas (including flowlines or intra-facility gathering lines or compressors) as feed to the natural gas processing plants are considered a part of the processing plant. Gathering and boosting stations that send the natural gas to an onshore natural gas transmission compression facility, or natural gas distribution facility, or to an end user are considered stand alone natural gas processing facilities. All residue gas compression equipment operated by a processing plant, whether inside or outside the processing plant fence, are considered part of the natural gas processing plant.

(4) *Onshore natural gas transmission compression.* Onshore natural gas transmission compression means any fixed combination of compressors that move natural gas at elevated pressure from production fields or natural gas processing facilities, in transmission pipelines, to natural gas distribution pipelines, or into storage. In addition, a transmission compressor station includes equipment for liquids separation, natural gas dehydration, and tanks for the storage of water and hydrocarbon liquids.

(5) *Underground natural gas storage.* Underground natural gas storage means subsurface storage, including depleted gas or oil reservoirs and salt dome caverns utilized for storing natural gas that has been transferred from its original location for the primary purpose of load balancing (the process of equalizing the receipt and delivery of natural gas); natural gas underground storage processes and operations (including compression, dehydration and flow measurement); and all the wellheads connected to the compression units located at the facility.

(6) *Liquefied natural gas (LNG) storage.* LNG storage means onshore LNG storage vessels located above ground, equipment for liquefying natural gas, compressors to capture and re-liquefy boil-off-gas, re-condensers, and vaporization units for re-gasification of the liquefied natural gas.

(7) *LNG import and export equipment.* LNG import equipment means all onshore or offshore equipment that receives imported LNG via ocean transport, stores LNG, re-gasifies LNG, and delivers re-gasified natural gas to a natural gas transmission or distribution system. LNG export equipment means all onshore or offshore equipment that receives natural gas, liquefies natural gas, stores LNG, and transfers the LNG via ocean transportation to any location, including locations in the United States.

(8) *Natural Gas Distribution.* Natural gas distribution means distribution pipelines (not interstate pipelines or intrastate pipelines) and metering and regulating stations that physically deliver natural gas to end users.

NOTE: Authority cited: Sections 39600, 39601, 39607, 39607.4, 41511, 38510, and 38530, Health and Safety Code. Reference: Sections 39600, 41511, and 38530, Health and Safety Code.

§ 95151. Reporting Threshold and Reporting Entity.

(a) The operator of a facility in section 95150 who is required to report under section 95101 of this article, and who is not eligible for abbreviated reporting under section 95103(a), must comply with this subarticle in reporting GHG emissions from petroleum and natural gas systems to ARB.

(1) For the purposes of reporting for onshore petroleum and natural gas production, the operator is the operating entity listed on the state well drilling permit, or the state operating permit for wells where no drilling permit is issued by the state, who operates onshore petroleum and natural gas production wells and controls by means of ownership (including leased and rented) and operation (including contracted) stationary and portable equipment located on all well pads within a single hydrocarbon basin as defined by the American Association of Petroleum Geologists (AAPG) three-digit Geological Province Code (published 1991). Where more than one entity holds the state well drilling permit, or well operating permit where no well drilling permit is issued by the state, the permitted entities for the facility must designate one entity to report all emissions from the jointly controlled facility. Where an operating entity holds more than one permit to operate wells in a basin, then all onshore petroleum and natural gas production well permits in their name in the basin, including all equipment on well pads, would be considered one onshore petroleum and natural gas production facility for the purposes of reporting under this article.

(b) In determining whether a facility in section 95150 meets the reporting threshold defined in section 95101(e), the operator must include combustion emissions from portable equipment that cannot move on roadways under its own power and drive train and that is stationed at a wellhead, including drilling rigs, dehydrators, compressors, electrical generators, steam boilers, and heaters.

NOTE: Authority cited: Sections 39600, 39601, 39607, 39607.4, 41511, 38510, and 38530, Health and Safety Code. Reference: Sections 39600, 41511, and 38530, Health and Safety Code.

§ 95152. GHGs to Report.

(a) The operator must monitor, calculate and report CO_2, CH_4, and N_2O emissions as applicable from each source type specified in paragraphs (b) through (i) of this section, according to the requirements of sections 95153 through 95156.

(b) For offshore petroleum and natural gas production, the operator must report emissions from all "stationary fugitive" and "stationary vented" sources as identified in the Minerals Management Service (MMS) Gulfwide Offshore Activity Data System (GOADS) study (2005 Gulfwide Emission Inventory Study MMS 2007-067).

(c) For onshore petroleum and natural gas production, the operator must report emissions from the following source types:

(1) Natural gas pneumatic high bleed device venting.
(2) Natural gas pneumatic low bleed device venting.
(3) Natural gas driven pneumatic pump venting.
(4) Well venting for liquids unloading.
(5) Gas well venting during conventional well completions.
(6) Gas well venting during unconventional well completions.
(7) Gas well venting during conventional well workovers.
(8) Gas well venting during unconventional well workovers.
(9) Gathering pipeline fugitives.
(10) Storage tanks.
(11) Reciprocating compressor rod packing venting.
(12) Well testing venting and flaring.
(13) Associated gas venting and flaring.
(14) Dehydrator vent stacks.
(15) Coal bed methane produced water emissions.
(16) EOR injection pump blowdown.
(17) Acid gas removal vent stacks.
(18) Centrifugal compressor wet seal degassing venting.
(19) Produced water dissolved CO_2.
(20) Fugitive emissions from valves, connectors, open ended lines, pressure relief valves, compressor starter gas vents, pumps, flanges, and other fugitive sources (such as instruments, loading arms, pressure relief valves, stuffing boxes, compressor seals, dump lever arms, and breather caps for crude services).

(d) For onshore natural gas processing, the operator must report emissions from the following sources:

(1) Reciprocating compressor rod packing venting.
(2) Centrifugal compressor wet seal degassing venting.
(3) Storage tanks.
(4) Blowdown vent stacks.
(5) Dehydrator vent stacks.
(6) Acid gas removal vent stacks.
(7) Flare stacks.
(8) Gathering pipeline fugitives.
(9) Fugitive emissions from: valves, connectors, open ended lines, pressure relief valves, meters, and centrifugal compressor dry seals.

(e) For onshore natural gas transmission compression, the operator must report emissions from the following sources:

(1) Reciprocating compressor rod packing venting.

(2) Centrifugal compressor wet seal degassing venting.
(3) Blowdown vent stacks.
(4) Natural gas pneumatic high bleed device venting.
(5) Natural gas pneumatic low bleed device venting.
(6) Fugitive emissions from connectors, block valves, control valves, compressor blowdown valves, pressure relief valves, orifice meters, other meters, regulators, and open ended lines.

(f) For underground natural gas storage, the operator must report emissions from the following sources:

(1) Reciprocating compressor rod packing venting.
(2) Centrifugal compressor wet seal degassing venting.
(3) Natural gas pneumatic high bleed device venting.
(4) Natural gas pneumatic low bleed device venting.
(5) Fugitive emissions from connectors, block valves, control valves, compressor blowdown valves, pressure relief valves, orifice meters, other meters, regulators, and open ended lines.

(g) For LNG storage, the operator must report emissions from the following sources:

(1) Reciprocating compressor rod packing venting.
(2) Centrifugal compressor wet seal degassing venting.
(3) Fugitive emissions from valves, pump seals, connectors, vapor recovery compressors, and other fugitive sources.

(h) For LNG import and export equipment, the operator must report emissions from the following sources:

(1) Reciprocating compressor rod packing venting.
(2) Centrifugal compressor wet seal degassing venting.
(3) Blowdown vent stacks.
(4) Fugitive emissions from valves, pump seals, connectors, vapor recovery compressors, and other fugitive sources.

(i) For natural gas distribution, the operator must report emissions from the following sources:

(1) Above ground meter regulators and gate station fugitive emissions from connectors, block valves, control valves, pressure relief valves, orifice meters, other meters, regulators, and open ended lines.
(2) Below ground meter regulators and vault fugitives.
(3) Pipeline main fugitives.
(4) Service line fugitives.

(j) The operator must report the CO_2, CH_4, and N_2O emissions from each flare.

(k) The operator must report emissions of CO_2, CH_4, and N_2O from each stationary fuel combustion unit by following the requirements of section 95115 of this article.

(l) The operator must report CO_2 emissions captured and transferred off site by following the requirements of section 95123 of this article.

NOTE: Authority cited: Sections 39600, 39601, 39607, 39607.4, 41511, 38510, and 38530, Health and Safety Code. Reference: Sections 39600, 41511, and 38530, Health and Safety Code.

§ 95153. Calculating GHG Emissions.

(a) *Natural Gas Pneumatic High Bleed Device and Pneumatic Pump Venting.* The operator must calculate emissions from natural gas high bleed flow control device venting using the applicable method below:

(1) Method 1: The operator must calculate vented CH_4 and CO_2 emissions using manufacturer data. The operator may use this method through reporting year 2013 when metering of natural gas consumption in all high bleed devices and pneumatic pumps is required. By January 1, 2013 natural gas consumption must be metered for 50 percent of the operator's pneumatic high bleed devices and pneumatic pumps, and the operator must use Method 2 in section 95153(a)(3) for these metered devices and pumps. The operator may use Method 1 to calculate emissions from all unmetered devices and pumps in 2013. By January 1, 2014, the operator must meter natural gas consumption for all pneumatic high bleed devices and pneumatic pumps, and use Method 2 in section 95153(a)(3) to calculate emissions.

(2) The operator must calculate natural gas emissions for all unmetered high bleed devices and pneumatic pumps using the following equation:

$$E_{nm} = \sum_{d/p=1}^{n} B_{d/p} * T$$

Where:

E_{nm} = Annual natural gas emissions at standard conditions, in cubic feet for all pneumatic high bleed devices and pumps where natural gas consumption is not metered.

n = Total number of un-metered high bleed devices and pumps.

$B_{d/p}$ = Natural gas driven pneumatic device or pump emissions rate at standard conditions in cubic feet per minute, as provided by the manufacturer.

T = Amount of time in minutes that the pneumatic device or pump has been operational through the reporting period.

(3) Method 2: The operator must calculate vented emissions for all metered pneumatic high bleed devices and pneumatic pumps using the following equation:

$$E_m = \sum_{1}^{n} B_n$$

Where:

E_m = Annual natural gas emissions at standard conditions, in cubic feet for all pneumatic high bleed devices and pneumatic pumps where gas is metered.

n = Total number of meters

B_n = Natural gas consumption for meter n.

(4) For both Method 1 and Method 2 of this paragraph, CH_4 and CO_2 volumetric and mass emissions must be calculated from volumetric natural gas emissions using calculations in paragraphs (s) and (t) of this section.

(b) *Natural Gas Pneumatic Low Bleed Device Venting.* The operator must calculate CH_4 and CO_2 emissions from natural gas pneumatic low bleed devices using the following equation:

$$E_{LB} = \sum_{LB=1}^{n} B_{LB} * T$$

Where:

E_{LB} = Annual natural gas emissions at standard conditions, in cubic feet for all pneumatic low bleed devices where natural gas consumption is not metered.

n = Total number of low bleed devices

B_{LB} = Natural gas driven low bleed pneumatic device emissions rate at standard conditions in cubic feet per minute, as provided by the manufacturer.

T = Amount of time in minutes that the pneumatic low bleed device has been operational during the reporting period.

(1) CH_4 and CO_2 volumetric and mass emissions must be calculated from volumetric natural gas emissions using calculations in paragraphs (s) and (t) of this section.

(c) *Acid Gas Removal (AGR) Vent Stacks.* For AGR (including processes such as amine, membrane, molecular sieve or other absorbents and adsorbents), the operator must calculate emissions for CO_2 using the following equation:

$$E_{a,CO2} = (V_1 * \%Vol_1) - (V_2 * \%Vol_2)$$

Where:

$E_{a,CO2}$ = Annual volumetric CO_2 emissions at ambient condition, in cubic feet per year.

V_1 = Metered total annual volume of natural gas flow into AGR unit in cubic feet per year at ambient condition.

$\%Vol_1$ = Volume weighted CO_2 content of natural gas into the AGR unit.

V_2 = Metered total annual volume of natural gas flow out of the AGR unit in cubic feet per year at ambient condition.

$\%Vol_2$ = Volume weighted CO_2 content of natural gas out of the AGR unit.

(1) If a continuous gas analyzer is installed, then the continuous gas analyzer results must be used. If a continuous gas analyzer is not available, quarterly gas samples must be taken to determine $\%Vol_1$ and $\%Vol_2$ according to methods set forth in section 95154(a)(2) of this article.

(2) If AGR vent stack emissions are captured and re-injected into the oil/gas field, operators are exempt from reporting AGR vent stack emissions.

(3) The operator must calculate CO_2 volumetric emissions at standard conditions using calculations in paragraph (r) of this section.

(4) Mass CO_2 emissions must be calculated from volumetric CO_2 emissions using calculations in paragraphs (s) and (t) of this section.

(d) *Dehydrator Vent Stacks.* For dehydrator vent stacks without vapor recovery or thermal control devices, the operator must calculate annual mass CH_4 and CO_2 emissions at standard temperature and pressure (STP) conditions using the simulation software package GRI-GLYCalc Version 4.0 (published 2008).

(1) A minimum of the following parameters must be used for characterizing emissions from dehydrators:

(A) Feed natural gas flow rate.
(B) Feed natural gas water content.
(C) Outlet natural gas water content.
(D) Absorbent circulation pump type (natural gas pneumatic/ air pneumatic/ electric).
(E) Absorbent circulation rate.
(F) Absorbent type: including triethylene glycol (TEG), diethylene glycol (DEG) or ethylene glycol (EG).
(G) Use of stripping natural gas.
(H) Use of flash tank separator (and disposition of recovered gas).
(I) Hours operated.
(J) Wet natural gas temperature, pressure, and composition.

(2) The operator must calculate annual emissions from dehydrator vent stacks to flares or regenerator fire-box/fire tubes as follows:

(A) The operator must use the dehydrator vent stack volume and gas composition as determined in paragraph (e)(1) of this section.

(B) The operator must use the calculation methodology of flare stacks in paragraph (l) of this section to determine dehydrator vent stack emissions from the flare or regenerator combustion gas vent.

(3) Operators of dehydrators that use desiccant must calculate emissions from the amount of gas vented from the vessel every time it is depressurized for the desiccant refilling process using the following equation:

$$E_{s,n} = \sum_{1}^{n} \left(H * D^2 * \pi * P_2 * \%G\right)/\left(4 * P_1 * 1{,}000 cf/Mcf\right)$$

Where:

$E_{s,n}$ = Annual natural gas emissions at standard conditions (Mcf).
n = number of desiccant refillings during reporting period
H = Height of the dehydrator vessel (ft).
D = Inside diameter of the vessel (ft).
P_1 = Atmospheric pressure (psia) default = 14.7 psia.
P_2 = Pressure of the gas (psia).
π = pi (3.1416).
%G = Percent of packed vessel volume that is gas.

(A) Both CH_4 and CO_2 volumetric and mass emissions must be calculated from volumetric natural gas emissions using calculations in paragraphs (s) and (t) of this section.

(e) *Well Venting For Liquids Unloadings*

(1) The operator must calculate emissions from each well venting for liquids unloading using the following equation:

$$E_{s,n} = \left\{\left(0.371 * 10^{-3}\right) * CD^2 * WD * SP * V\right\} + \left\{SFR * HR\right\}$$

Where:

$E_{s,n}$ = Annual natural gas emissions at standard conditions, in cubic feet/year.
$0.371 * 10^{-3}$ = {pi(3.1416)/4}/{(14.7*144) psia converted to pounds per square feet}
CD = Casing diameter (inches).
WD = Well depth (feet).
SP = Shut-in pressure (psig).
V = Number of vents per year.
SFR = Sales flow rate of gas well in cubic feet per hour immediately prior to the venting event.

HR = Hours that the well was left open to the atmosphere during unloading.

(2) Both CH_4 and CO_2 volumetric and mass emissions must be calculated from volumetric natural gas emissions using calculations in paragraphs (s) and (t) of this section.

(f) *Gas Well Venting During Unconventional Well Completions and Workovers.*

(1) The operator must calculate emissions from unconventional gas well venting during well completions and workovers from hydraulic fracturing using the following equation:

$$E_{a,n} = T * FR$$

Where:

$E_{a,n}$ = Annual natural gas vented emissions at ambient conditions in cubic feet.
T = Cumulative amount of time in hours of well venting during the year.
FR = Gas Flow Rate in cubic feet per hour, under ambient conditions, as required in paragraph (f)(1) of this section.

(2) The operator must calculate natural gas volumetric emissions at standard conditions using calculations in paragraph (r) of this section.

(3) Both CH_4 and CO_2 volumetric and mass emissions must be calculated from volumetric natural gas emissions using calculations in paragraphs (s) and (t) of this section.

(4) The flow rate for gas well venting during well completions and workovers from hydraulic fracturing must be determined using either of the calculation methodologies described in subparagraphs (A) and (B) below. The same calculation methodology must be used for the entire reporting year.

(A) Calculation Methodology 1. For one well completion in each gas producing field and for one well workover in each gas producing field, a recording flow meter must be installed on the vent line during each well unloading event according to methods set forth in section 95154(a)(2) of this article.

1. The average flow rate in cubic feet per minute of venting must be calculated for one well completion in each field and for one well workover in each field.
2. The respective flow rates must be applied to all well completions in the field and to all well workovers in the field, multiplied by the number of minutes of venting of all well completions and workovers, respectively, in that field.

3. New flow rates for completions and workovers must be calculated every other year for each reporting field and horizon.

(B) Calculation Methodology 2. For one well completion in each gas producing field and for one well workover in each gas producing field, the operator must record the pressures measured before and after the well choke according to methods set forth in section 95154(a)(2) of this article.

1. The average flow rate in cubic feet per minute of venting across the choke must be calculated for one well completion in each field and for one well workover in each field.
2. The respective flow rates must be applied to all well completions in the field and to all well workovers in the field, multiplied by the number of minutes of venting of all well completions and workovers in that field.
3. New flow rates for completions and workovers must be calculated every other year for each reporting field and horizon.

(C) The operator must calculate natural gas volumetric emissions at standard conditions using calculations in paragraph (r) of this section.

(D) Both CH_4 and CO_2 volumetric and mass emissions must be calculated from volumetric natural gas emissions using calculations in paragraphs (s) and (t) of this section.

(E) The operator must calculate annual emissions from gas well venting during well completions and workovers to flares as follows:

1. The operator must use the gas well venting volume during well completions and workovers as determined in paragraph (f)(4) of this section.
2. The operator must use the calculation methodology of flare stacks in paragraph (l) of this section to determine gas well venting during well completions and workovers emissions from the flare.

(g) *Gas Well Venting During Conventional Well Completions and Workovers.* The operator must calculate emissions from each gas well venting during conventional well completions and workovers using the following equation:

$$E_{a,n} = \sum_{1}^{n} V * T$$

Where:

$E_{a,n}$ = Annual emissions in cubic feet at ambient conditions from gas well ventings during conventional well completions or workovers.

n = number of venting events per reporting period.

V = Daily gas production rate in cubic feet per minute immediately prior to venting event.

T = Cumulative amount of time of well venting in minutes during venting event.

(1) The operator must calculate natural gas volumetric emissions at standard conditions using calculations in paragraph (r) of this section.
(2) Both CH_4 and CO_2 volumetric and mass emissions must be calculated from volumetric natural gas emissions using calculations in paragraphs (s) and (t) of this section.

(h) *Blowdown Vent Stacks.* The operator must calculate blowdown vent stack emissions as follows:

(1) The operator must calculate the total volume (including from pipelines, compressor case or cylinders, manifolds, suction and discharge bottles and vessels) between isolation valves.
(2) The operator must retain logs of the number of blowdowns for each equipment type according to the recordkeeping requirements of section 95105 of this article.
(3) The operator must calculate the total annual venting emissions using the following equation:

$$E_{a,n} = N * V_v$$

Where:
$E_{a,n}$ = Annual natural gas venting emissions at ambient conditions from blowdowns in cubic feet.
N = Number of blowdowns for the equipment in reporting year.
V_v = Total volume of blowdown equipment chambers (including pipelines, compressors and vessels) between isolation valves in cubic feet.

(4) The operator must calculate natural gas volumetric emissions at standard conditions using calculations in paragraph (r) of this section.
(5) The operator must calculate both CH_4 and CO_2 volumetric and mass emissions from volumetric natural gas emissions using calculations in paragraphs (s) and (t) of this section.

(i) *Onshore Production and Processing Storage Tanks.* For emissions from atmospheric pressure storage tanks receiving produced liquids from onshore petroleum and natural gas production facilities (including stationary liquid storage not owned or operated by the reporter) and onshore natural gas processing facilities, the operator must calculate annual CH_4 and CO_2 emissions using the appropriate method below. For storage tank batteries where the oil production rate is 10 barrels per day or less the operator must use Method 1. For storage tank batteries where the oil production rate is greater than 10 barrels per day the operator must use Method 2.

(1) Method 1: The operator must use this method for storage tank batteries where the oil production rate is 10 barrels per day or less. The operator must use E&P Tank Version 2.0 to calculate CH_4 and CO_2 emissions.

(A) A minimum of the following parameters must be used to characterize emissions from liquid transfer to atmospheric pressure storage tanks.

1. Separator oil composition.
2. Separator temperature.
3. Separator pressure.
4. Sales oil API gravity.
5. Sales oil production rate.
6. Sales oil Reid vapor pressure.
7. Ambient air temperature.
8. Ambient air pressure.

(B) The operator must determine if the storage tank has vapor recovery or thermal control devices.

1. The operator must adjust the emissions estimated using E&P Tank downward by the magnitude of emissions captured using a vapor recovery system for beneficial use.

(C) The operator must calculate emissions from liquids sent to atmospheric storage tanks vented to flares as follows:

1. The operator must use the storage tank emissions volume and gas composition as determined in this section.
2. The operator must use the calculation methodology of flare stacks in paragraph (l) of this section to determine storage tank emissions from the flare.

(D) If liquids are sent to atmospheric storage tanks where the tank emissions are not represented by the equilibrium conditions of the liquid in a gas-liquid separator and calculated by E&P Tank, then emissions must be calculated as follows:

1. The operator must use the storage tank emissions as determined in this section.
2. The operator must multiply the emissions by 3.87 for sales oil less than 45 API gravity.
3. The operator must multiply the emissions by 5.37 for sales oil equal to or greater than 45 API gravity.

(2) Method 2: The operator must use the following method for storage tanks where the oil production rate is greater than 10 barrels per day.

(A) The operator must annually determine the Gas-Oil Ratio (GOR) of produced liquids (crude and condensate) for each storage tank. An additional sample must be collected, analyzed and emissions calculated when one or more producing wells are connected to or disconnected from the storage tank. Measurements are limited to land-based storage tanks containing condensate and crude oil.

1. A pressurized sample must be collected at a point downstream of all field separators, prior to the point where produced liquid is flashed to atmospheric pressure as it enters the storage tank. Sampling must be conducted under unbiased operating conditions.
2. A flash liberation test must be conducted and GOR and the mass fraction of CH_4 and CO_2 in the evolved gas determined.
   The following steps outline the flash liberation test:
   Step 1. The fluid sample is charged to a PVT cell.
   Step 2. The cell pressure is elevated to a pressure higher than saturation pressure by injecting mercury.
   Step 3. Pressure is lowered in small increments until the PVT cell is at atmospheric pressure.
   Step 4. The resulting volume of solution gas and oil remaining are measured and corrected to conditions of 60°F and 14.65 psia.
3. Storage tanks equipped with a vapor recovery unit (VRU) or thermal oxidizer are exempt from reporting during periods when the destruction device is operational.

(B) The operator must determine CH_4 and CO_2 emissions using the following equation.

$$E_{CH4/CO2} = GOR * PR * MW_g / MVC * MF_{CH4/CO2} * 0.001$$

Where:

$E_{CH4/CO2}$ =	Methane or carbon dioxide emissions (metric tons/year).
GOR =	Gas-Oil Ratio (scf/bbl).
PR =	Oil production rate (bbl/measurement period).
MW_g =	Molecular weight of the gas (kg/kg-mole).
MVC =	Molar volume conversion factor.
$MF_{CH4/CO2}$ =	Mass fraction of CH_4 or CO_2 in gas (kg GHG/kg gas).
0.001=	Conversion factor.

(j) *Well Testing Venting and Flaring.* The operator must calculate well testing venting and flaring emissions as follows:

(1) The operator must collect a pressurized crude/condensate sample and determine the gas to oil ratio (GOR) of the hydrocarbon production from each well tested.
(2) The operator must estimate venting emissions using the following equation:

$$E_{a,n} = GOR * FR * D$$

Where:
$E_{a,n}$ = Annual volumetric natural gas emissions from well testing in cubic feet under ambient conditions.
GOR = Gas- Oil Ratio in cubic feet of gas per barrel of oil; oil here refers to hydrocarbon liquids produced of all API gravities.
FR = Flow rate in barrels of oil per day for the well being tested.
D = Number of days during the year the well is tested.

(3) The operator must calculate natural gas volumetric emissions at standard conditions using calculations in paragraph (r) of this section.
(4) The operator must calculate both CH_4 and CO_2 volumetric and mass emissions from volumetric natural gas emissions using calculations in paragraphs (s) and (t) of this section.
(5) The operator must calculate emissions from well testing to flares as follows:

(A) The operator must use the well testing emissions volume and gas composition as determined in paragraphs (j)(1) through (3) of this section.
(B) The operator must use the calculation methodology of flare stacks in paragraph (l) of this section to determine well testing emissions from the flare.

(k) *Associated Gas Venting and Flaring.* The operator must calculate associated gas venting and flaring emissions as follows:

(1) The operator must collect a pressurized sample of crude/condensate and determine the GOR ratio of the hydrocarbon production from each well whose associated natural gas is vented or flared.
(2) The operator must estimate venting emissions using the following equation:

$$E_{a,n} = GOR * V$$

Where:
$E_{a,n}$ = Annual volumetric natural gas emissions from associated gas venting under ambient conditions, in cubic feet.
GOR = Gas to oil ratio in cubic feet of gas per barrel of oil; oil here refers to hydrocarbon liquids produced of all API gravities.
V = Total volume of oil produced in barrels in the reporting year.

(3) The operator must calculate natural gas volumetric emissions at standard conditions using calculations in paragraph (r) of this section.
(4) The operator must calculate both CH_4 and CO_2 volumetric and mass emissions from volumetric natural gas emissions using calculations in paragraphs (s) and (t) of this section.
(5) The operator must calculate emissions from associated natural gas to flares as follows:

(A) The operator must use the associated natural gas volume and gas composition as determined in paragraph (k)(1) through (3) of this section.
(B) The operator must use the calculation methodology of flare stacks in paragraph (l) of this section to determine associated gas emissions from the flare.

(l) *Flare Stacks.* The operator must calculate emissions from each flare stack as follows:

(1) If a continuous flow measurement device is installed on the flare, the operator must use the measured flow volumes to calculate the flare gas emissions. If a continuous flow measurement device is not installed on the flare, the operator can install a flow measuring device on the flare or use engineering calculations or company records to estimate volumetric flare gas flow.
(2) If a continuous gas composition analyzer is installed on gas to the flare, the operator must use these compositions in calculating emissions. If a continuous gas composition analyzer is not installed on gas to the flare, the operator can install a continuous gas composition analyzer on the flare or use the appropriate gas compositions for each stream of hydrocarbons going to the flare as specified in subparagraphs (A)-(B) below.

(A) When the stream going to flare is natural gas, the operator must use the GHG mole percent in feed natural gas for all streams upstream of the de-methanizer and GHG mole percent in facility specific residue gas to transmission pipeline systems for all emissions sources downstream of the de-methanizer overhead for onshore natural gas processing facilities.
(B) When the stream going to the flare is a hydrocarbon product stream, such as ethane or butane, then the operator must use a representative composition from the source for the stream.

(3) The operator must determine flare combustion efficiency from manufacturer supplied flare specifications. If not available, the operator must assume a flare combustion efficiency of 98 percent.
(4) The operator must determine CO_2, CH_4, and N_2O emissions resulting from the combustion of natural gas used as pilot gas according to the requirements of section 95115 of this article.

(5) For each unique gas stream destructed in the flare, the operator must calculate annual GHG volumetric emissions at actual conditions using the applicable equations below.

(A) The operator must calculate un-combusted flare stack methane emissions using the following equation:

$$E_{a,CH4} = V_a * (1-\eta) * X_{CH4}$$

Where:
$E_{a,CH4}$ = Uncombusted methane emissions from the flare stack (scf).
V_a = Volume of gas sent to the flare (scf).
η = Flare destruction efficiency (expressed as a decimal, default = 0.98).
X_{CH4} = Concentration of methane in gas sent to the flare.

(B) The operator must calculate CO_2 combustion emissions for each unique gas stream sent flare using the following equation:

$$E_{CO2} = \eta * V * CC / MVC * 3.664 * 0.001$$

Where:
E_{CO2} = Combustion CO_2 emissions (MT of CO_2).
η = Flare destruction efficiency (expressed as a decimal, default = 0.98).
V = Volume of gas or liquid sent to the flare (scf).
CC = Carbon content of gas stream sent to the flare (kg C/kg-mole).
MVC = Molar volume conversion.
3.664 = Conversion factor (kg C to kg CO_2).
0.001 = Conversion factor (kg to metric tons).

1. The operator must calculate GHG volumetric emissions at standard conditions using calculations in paragraph (r) of this section.
2. The operator must calculate both CH_4 and CO_2 mass emissions from volumetric CH_4 and CO_2 emissions using calculation in paragraph (t) of this section.
3. The operator must calculate N_2O emissions using the emission factors for Gas Flares listed in Table 8 of section 95158.
4. This emissions source excludes any emissions calculated under other emissions sources in section 95153 of this article.

(m) *Centrifugal Compressor Wet Seal Degassing Vents.* The operator must calculate CO_2 and CH_4 emissions from centrifugal compressor wet seal degassing vents as follows:

(1) For each centrifugal compressor, the operator must determine the volume of vapors from wet seal oil degassing tanks sent to an atmospheric vent or flare using a temporary or permanent flow measurement meter such as a vane anemometer according to methods set forth in section 95154(a)(2) of this article.

(2) The operator must estimate annual emissions using meter flow measurement using the following equation:

$$E_{a,i} = MT * T * M_i * (1 - B)$$

Where:

$E_{a,i}$ = Annual GHG i (i = either CH_4 or CO_2) volumetric emissions at ambient conditions.

MT = Average meter reading of gas emissions per unit time based on semi-annual measurements.

T = Total time the compressor associated with the wet seal(s) is operational in the reporting year.

M_i = Average mole percent of GHG i in the degassing vent gas based on semi-annual measurement; use the appropriate gas compositions in paragraph (s)(2) of this section.

B = Percentage of centrifugal compressor wet seal degassing vent gas sent to vapor recovery or fuel gas or other beneficial use as determined by keeping logs of the number of operating hours for the vapor recovery system and the amount of vent gas that is directed to the fuel gas system.

(3) The operator must calculate CH_4 and CO_2 volumetric emissions at standard conditions using paragraph (r) of this section.

(4) The operator must calculate both CH_4 and CO_2 mass emissions from volumetric emissions using calculations in paragraph (t) of this section.

(5) The operator must calculate emissions from degassing vent vapors to flares as follows:

(A) The operator must use the degassing vent vapor volume and gas composition as determined in paragraphs (m)(1) through (3) of this section.

(B) The operator must use the calculation methodology of flare stacks in paragraph (l) of this section to determine degassing vent vapor emissions from the flare.

(n) *Reciprocating Compressor Rod Packing Venting.* The operator must calculate annual CH_4 and CO_2 emissions from each reciprocating compressor rod packing venting for each applicable operational mode as follows:

(1) The operator must estimate annual emissions using a meter flow measurement using the following equation:

$$E_{a,i} = MT * T * M_i$$

Where:

$E_{a,i}$ = Annual GHG i (i = either CH_4 or CO_2) volumetric emissions at ambient conditions.

MT = Meter volumetric reading of gas emissions per unit time, under ambient conditions.

T = Total time the compressor associated with the venting is operational in the reporting year.

M_i = Mole percent of GHG i (i = either CO_2 or CH_4) in the vent gas; use the appropriate gas compositions in paragraph (s)(2) of this section.

(2) If the rod packing case is connected to an open ended vent line then the operator must use the following method to calculate emissions.

(A) The operator must measure volumetric emissions from all vents (including emissions manifolded to common vents) including rod packing, unit isolation valves, and blowdown valves using bagging according to methods set forth in section 95154(a)(3) of this article.

(B) The operator must use a temporary meter such as a vane anemometer or a permanent meter such as an orifice meter to measure emissions from all vents (including emissions manifolded to a common vent) including rod packing vents, unit isolation valves, and blowdown valves according to methods set forth in section 95154(a)(2).

(3) If the rod packing case is not equipped with a vent line, the operator must use the following method to estimate emissions:

(A) The operator must use the methods described in 95154(a) to conduct annual leak detection of fugitive emissions from the packing case into an open distance piece, or from the compressor crank case breather cap or vent with a closed distance piece.

(B) The operator must measure emissions using a high flow sampler, or calibrated bag, or appropriate meter according to methods set forth in section 95154(b) of this article.

(4) The operator must conduct one measurement for each compressor in each of the following operational modes that occurs during a reporting period:

(A) Operating.
(B) Standby, pressurized.
(C) Not operating, depressurized.

(5) The operator must calculate CH_4 and CO_2 volumetric emissions at standard conditions using calculations in paragraph (r) of this section.
(6) The operator must estimate CH_4 and CO_2 volumetric and mass emissions from volumetric natural gas emissions using the calculations in paragraphs (s) and (t) of this section.

(o) *Leak Detection and Leaker Emission Factors.* The operator must use the methods described in section 95154(a) of this article to conduct an annual leak detection of fugitive emissions from all sources listed in section 95152(d)(9), (e)(7), (f)(5), (g)(3), (h)(4), and (i)(1) of this article. This paragraph (o) applies to emissions sources in streams with gas content greater than 10 percent CH_4 plus CO_2 by weight. Emissions sources in streams with gas content less than 10 percent CH_4 plus CO_2 by weight do not need to be reported. If fugitive emissions are detected for sources listed in this paragraph, the operator must calculate emissions using the following equation for each source with fugitive emissions:

$$E_{s,i} = \text{Count} * EF * GHG_i * T$$

Where:
$E_{s,i}$ = Annual total volumetric GHG emissions at standard conditions from each component fugitive source.
Count = Total number of this type of emission source found to be leaking.
EF = Leaker emission factor for specific sources listed in Tables 2 through 7 of section 95158.
GHG_i = Concentration of GHG i, (i = either CH_4 or CO_2), in the total hydrocarbon of the feed natural gas.
T = Total time the specific source associated with the fugitive emission was operational in the reporting year, in hours.

(1) The operator must calculate GHG mass emissions at standard conditions using the calculation in paragraph (t) of this section.
(2) Operators of onshore natural gas processing facilities must use the appropriate default leaker emission factors listed in Table 2 of section 95158 for fugitive emissions detected from valves, connectors, open ended lines, pressure relief valves, meters, and centrifugal compressor dry seals.
(3) Operators of onshore natural gas transmission compression facilities must use the appropriate default leaker emission factors listed in Table 3 of section 95158 for fugitive emissions detected from connectors, block valves, control valves, compressor blowdown valves, pressure relief valves, orifice meters, other meters regulators, and open ended lines.
(4) Operators of underground natural gas storage facilities for storage stations must use the appropriate default leaker emission factors listed in Table 4 of section 95158 for fugitive emissions detected from connectors, block valves, control valves, compressor blowdown valves, pressure relief valves, orifice meters, other meters, regulators, and open ended lines.

(5) Operators of LNG storage facilities must use the appropriate default leaker emission factors listed in Table 5 of section 95158 for fugitive emissions detected from valves, pump seals, connectors, and other.

(6) Operators of LNG import and export facilities must use the appropriate default leaker emission factors listed in Table 6 of section 95158 for fugitive emissions detected from valves, pump seals, connectors, and other.

(7) Operators of natural gas distribution facilities for above ground meter regulator and gate stations must use the appropriate default leaker emission factors listed in Table 7 of section 95158 for fugitive emissions detected from connectors, block valves, control valves, pressure relief valves, orifice meters, other meters, regulators, and open ended lines.

(p) *Population Count and Emission Factors.* This paragraph applies to emissions sources listed in section 95152(c)(2), (c)(9), (c)(15), (c)(21), (d)(8), (e)(6), (f)(4), (f)(5), (g)(3), (h)(4), (i)(2), (i)(3) and (i)(4), of this article on streams with gas content greater than 10 percent CH_4 plus CO_2 by weight. Emissions sources in streams with gas content less than 10 percent CH_4 plus CO_2 by weight do not need to be reported. Operators must calculate emissions from all sources listed in this paragraph using the following equation:

$$E_{s,i} = \text{Count} * EF * GHG_i * T$$

Where:

$E_{s,i}$ = Annual total volumetric GHG emissions at standard conditions from each fugitive source.

Count = Total number of this type of emission source at the facility.

EF = Population emission factor for specific sources listed in Tables 1 through 7 of section 95158.

GHG_i = Concentration of GHG i, (i = either CH_4 or CO_2), in produced natural gas or feed natural gas.

T = Total time the specific source associated with the fugitive emission was operational in the reporting year, in hours.

(1) Operators must calculate both CH_4 and CO_2 mass emissions from volumetric emissions using the calculation in paragraph (t) of this section.

(2) Operators of onshore petroleum and natural gas production facilities must use the appropriate default population emission factors listed in Table 1 of section 95158 for fugitive emissions from valves, connectors, open ended lines, pressure relief valves, compressor starter gas vent, pump, flanges, other, and CBM well water production. Where facilities conduct EOR operations, the emissions factor listed in Table 1 of section 95158 must be used to estimate all stream of gases, including recycle CO_2 stream. In cases where the stream is almost all CO_2, the emissions factors in Table 1 of section 95158 must be assumed to be for CO_2 instead of natural gas.

(3) Operators of onshore natural gas processing facilities must use the appropriate default population emission factor listed in Table 2 of section 95158 for fugitive emission from gathering pipelines.

(4) Operators of underground natural gas storage facilities for storage wellheads must use the appropriate default population emission factors listed in Table 4 of section 95158 for fugitive emissions from connectors, valves, pressure relief valves, and open ended lines.

(5) Operators of LNG storage facilities must use the appropriate default population emission factors listed in Table 5 of section 95158 for fugitive emissions from vapor recovery compressors.

(6) Operators of LNG import and export facilities must use the appropriate default population emission factor listed in Table 6 of section 95158 for fugitive emissions from vapor recovery compressors.

(7) Operators of natural gas distribution facilities must use the appropriate default population emission factors listed in Table 7 of section 95158 for fugitive emissions from below grade metering & regulating (M&R) stations, gathering pipelines, mains, and services.

(q) *Offshore Petroleum and Natural Gas Production Facilities.* Operators must report GHG emissions from all "stationary fugitive" and "stationary vented" sources as identified in the Minerals Management Service (MMS) Gulfwide Offshore Activity Data System (GOADS) study (2005 Gulfwide Emission Inventory Study MMS 2007-067) for each platform. Operators of offshore production facilities who had not previously reported under the MMS GOADS program must collect monthly activity data from platform sources for the first reporting year in accordance with the MMS GOADS program instructions. Annual emissions must be calculated using the MMS GOADS emission factors and methods.

(1) In subsequent reporting years, facilities not reporting under GOADS must follow the same data collection cycle as GOADS in collecting new activity data monthly to estimate emissions and report emissions.

(2) For each reporting year that does not overlap with the GOADS reporting year, operators must report the last reported emissions data with emissions adjusted based on the operating time for each platform.

(3) If MMS discontinues or delays their GOADS survey by more than 4 years, then platform operators must collect monthly activity data every 4 years from platform sources in accordance with the MMS GOADS program instructions, and annual emissions must be calculated using the MMS GOADS emission factors and methods.

(r) *Volumetric Emissions.* Operators must calculate volumetric emissions at standard conditions as specified in paragraphs (r)(1) or (2) of this section.

(1) Operators must calculate natural gas volumetric emissions at standard conditions by converting ambient temperature and pressure of natural gas emissions to standard temperature and pressure natural gas using the following equation:

$$E_{s,n} = E_{a,n} * (460 + T_s) * P_a / (460 + T_a) * P_s$$

Where:

$E_{s,n}$ = Natural gas volumetric emissions at standard temperature and pressure (STP) conditions.

$E_{a,n}$ = Natural gas volumetric emissions at ambient conditions.

T_s = Temperature at standard conditions (°F).

T_a = Temperature at actual emission conditions (°F).

P_s = Absolute pressure at standard conditions (inches of Hg).

P_a = Absolute pressure at ambient conditions (inches of Hg).

(2) Calculate GHG volumetric emissions at standard conditions by converting ambient temperature and pressure of GHG emissions to standard temperature and pressure using the following equation:

$$E_{s,i} = E_{a,i} * (460 + T_s) * P_a / (460 + T_a) * P_s$$

Where:

$E_{s,i}$ = GHG i volumetric emissions at standard temperature and pressure (STP) conditions.

$E_{a,i}$ = GHG i volumetric emissions at actual conditions.

T_s = Temperature at standard conditions (°F).

T_a = Temperature at actual emission conditions (°F).

P_s = Absolute pressure at standard conditions (inches of Hg).

P_a = Absolute pressure at ambient conditions (inches of Hg).

(s) *GHG Volumetric Emissions.*

(1) Operators must estimate CH_4 and CO_2 emissions from natural gas emissions using the following equation:

$$E_{s,i} = E_{s,n} * M_i$$

Where:

$E_{s,i}$ = GHG i (i = either CH_4 or CO_2) volumetric emissions at standard conditions.

$E_{s,n}$ = Natural gas volumetric emissions at standard conditions.

M_i = Mole percent of GHG i (i = CH_4 or CO_2) in the natural gas.

(2) For the equation in paragraph (s)(1), the mole percent, M_i, must be the annual average mole percent for each facility, as specified in paragraphs (s)(2)(A) through (G) of this section.

(A) GHG mole percent in produced natural gas for onshore petroleum and natural gas production facilities. If operators have a continuous gas composition analyzer installed for produced natural gas, the operator must use these values in calculating emissions. If the operator does not

have a continuous gas composition analyzer installed, then quarterly samples must be taken according to methods set forth in section 95154(a)(2) of this article.

(B) GHG mole percent in feed natural gas for all emissions sources upstream of the de-methanizer and GHG mole percent in facility specific residue gas to transmission pipeline systems for all emissions sources downstream of the de-methanizer overhead for onshore natural gas processing facilities. If the operator has a continuous gas composition analyzer on feed natural gas, the operator must use these values in calculating emissions. If the operator does not have a continuous gas composition analyzer, then quarterly samples must be taken according to methods set forth in section 95154(a)(2) of this article.

(C) GHG mole percent in transmission pipeline natural gas that passes through the facility for onshore natural gas transmission compression facilities.

(D) GHG mole percent in natural gas stored in underground natural gas storage facilities.

(E) GHG mole percent in natural gas stored in LNG storage facilities.

(F) GHG mole percent in natural gas stored in LNG import and export facilities.

(G) GHG mole percent in local distribution pipeline natural gas that passes through the facility for natural gas distribution facilities.

(t) *GHG Mass Emissions.* The operator must calculate GHG mass emissions at standard conditions by converting the GHG volumetric emissions into mass emissions using the following equation:

$$Mass_{s,i} = E_{s,i} * \rho_i * 10^{-3}$$

Where:

$Mass_{s,i}$ = GHG i (either CH_4 or CO_2) mass emissions at standard conditions in metric tons.

$E_{s,i}$ = GHG i (either CH_4 or CO_2) volumetric emissions at standard conditions, in cubic feet.

ρ_i = Density of GHG i, 0.053 kg/ft^3 for CO_2 and 0.0193 kg/ft^3 for CH_4.

(u) *EOR Injection Pump Blowdown.* The operator must calculate pump blowdown emissions as follows:

(1) The operator must calculate the total volume in cubic feet (including from pipelines, compressors and vessels) between isolation valves.

(2) The operator must retain logs of the number of blowdowns per reporting period according to the recordkeeping requirements of section 95105 of this article.

(3) The operator must calculate the total annual venting emissions using the following equation:

$$Mass_{c,i} = N * V_v * R_c * GHG_i * 10^{-3}$$

Where:

$Mass_{c,i}$ = Annual EOR injection gas venting emissions in metric tons at critical conditions "c" from blowdowns.

N = Number of blowdowns for the equipment in reporting year.

V_v = Total volume in cubic feet of blowdown equipment chambers (including pipelines, compressors, manifolds and vessels) between isolation valves.

R_c = Density of critical phase EOR injection gas in kg/ft^3.

GHG_i = Mass fraction of GHG_i in critical phase injection gas.

(v) *Produced Water Dissolved CO_2.* The operator must calculate dissolved CO_2 in produced water as follows:

(1) The operator must determine the amount of CO_2 retained in produced water at STP conditions. Quarterly samples must be taken according to methods set forth in section 95154(a)(2) of this article to determine retention of CO_2 in produced water immediately downstream of the separator where hydrocarbon liquids and produced water are separated. The operator must use the average of the quarterly analysis for the reporting period.

(2) The operator must estimate emissions using the following equation:

$$Mass_{s,CO2} * S_{pw} * V_{pw}$$

Where:

$Mass_{s,CO2}$ = Annual CO_2 emissions from CO_2 retained in produced water beyond tankage, in metric tons.

S_{pw} = Amount of CO_2 retained in produced water in metric tons per barrel, under standard conditions.

V_{pw} = Total volume of produced water produced in barrels in the reporting year.

(3) EOR operations that route produced water from separation directly to re-injection into the hydrocarbon reservoir in a closed loop system without any leakage to the atmosphere are exempt from paragraph (v) of this section.

(w) *Portable Equipment Combustion Emissions.* The operator must calculate emissions from portable equipment pursuant to section 95115 of this article.

NOTE: Authority cited: Sections 39600, 39601, 39607, 39607.4, 41511, 38510, and 38530, Health and Safety Code. Reference: Sections 39600, 41511, and 38530, Health and Safety Code.

§ 95154. Monitoring and QA/QC Requirements.

(a) The operator must use the method described as follows to conduct annual leak detection of fugitive emissions from all source types listed in section 95153(n)(3)(A) and 95153(o) of this article in operation or on standby mode that occur during a reporting period.

(1) Optical gas imaging instrument. The operator must use an optical gas imaging instrument for fugitive emissions detection in accordance with 40 CFR part 60, subpart A, §60.18(i)(1) and (2), Alternative Work Practice for Monitoring Equipment Leaks (revised as of July 1, 2009). In addition, the operator must operate the optical gas imaging instrument to image the source types required by this article in accordance with the instrument manufacturer's operating parameters.

(2) All flow meters, composition analyzers and pressure gauges that are used to provide data for the GHG emissions calculations must use measurement methods, maintenance practices, and calibration methods that are consistent with the requirements of section 95103(k).

(3) The operator must use calibrated bags (also known as vent bags) only where the emissions are at near-atmospheric pressures such that it is safe to handle and capture all the emissions, below the maximum temperature specified by the vent bag manufacturer, and the entire emissions volume can be encompassed for measurement.

(A) The operator must hold the bag in place enclosing the emissions source to capture the entire emissions and record the time required for completely filling the bag. If the bag inflates in less than one second, assume one second inflation time.

(B) The operator must perform three measurements of the time required to fill the bag and report the emissions as the average of the three readings.

(C) The operator must estimate natural gas volumetric emissions at standard conditions using the calculations in section 95153(r) of this article.

(D) The operator must estimate CH_4 and CO_2 volumetric and mass emissions from volumetric natural gas emissions using the calculations in section 95153(s) and (t) of this article.

(b) The operator must use a high volume sampler to measure emissions within the capacity of the instrument.

(1) A technician following manufacturer instructions must conduct measurements, including equipment manufacturer operating procedures and measurement methodologies relevant to using a high volume sampler, including positioning the instrument for complete capture of the fugitive emissions without creating backpressure on the source.

(2) If the high volume sampler, along with all attachments available from the manufacturer, is not able to capture all the emissions from the source then the operator must use anti-static wraps or other aids to capture all emissions without violating operating requirements as provided in the instrument manufacturer's manual.
(3) The operator must estimate CH_4 and CO_2 volumetric and mass emissions from volumetric natural gas emissions using the calculations in section 95153(s) and (t) of this article.
(4) The operator must calibrate the instrument at 2.5 percent CH_4 with 97.5 percent air and 100 percent CH_4 by using calibrated gas samples and by following the manufacturer's instructions for calibration.

NOTE: Authority cited: Sections 39600, 39601, 39607, 39607.4, 41511, 38510, and 38530, Health and Safety Code. Reference: Sections 39600, 41511, and 38530, Health and Safety Code.

§ 95155. Procedures for Estimating Missing Data.

(a) A complete record of all estimated and/or measured parameters used in the GHG emissions calculations is required. If data are lost or an error occurs during annual emissions estimation or measurements, the operator must repeat the estimation or measurement activity for those sources within the measurement period. In cases where repeat sampling and/or analysis cannot be completed, the operator must follow the missing data substitution procedures below.

(1) To substitute for missing data for emissions reported under section 95115 of this article (stationary combustion units and units using continuous emissions monitoring systems), the operator must follow the requirements of section 95129 of this article.
(2) If data required by this subarticle are missing and additional sampling and/or analysis is not possible, the operator must generate a substitute value as follows:

(A) If the analytical data capture rate is at least 90 percent for the data year, the operator must substitute each missing value using available process data.
(B) If the analytical data capture rate is at least 80 percent but not at least 90 percent for the data year, the operator must substitute each missing value with the highest quality assured value recorded for the parameter during the given data year, as well as the two previous data years.
(C) If the analytical data capture rate is less than 80 percent for the data year, the operator must substitute each missing value with the highest quality assured value recorded for the parameter in all records kept according to section 95105(a).

NOTE: Authority cited: Sections 39600, 39601, 39607, 39607.4, 41511, 38510, and 38530, Health and Safety Code. Reference: Sections 39600, 41511, and 38530, Health and Safety Code.

§ 95156. Data Reporting Requirements.

In addition to the information required by 40 CFR §98.3(c), each annual report must contain reported emissions as specified in this section.

(a) The operator must report annual emissions separately for each of the industry segments listed in paragraphs (a)(1) through (a)(8) of this section. For each segment, the operator must report emissions from each source type in the aggregate, unless specified otherwise. For example, the operator of an underground natural gas storage operation with multiple reciprocating compressors must report emissions from all reciprocating compressors as an aggregate number.

(1) Onshore petroleum and natural gas production.

(A) Petroleum and natural gas produced using thermal EOR.
(B) Petroleum and natural gas produced using production methods other than thermal EOR.

(2) Offshore petroleum and natural gas production.
(3) Onshore natural gas processing.
(4) Onshore natural gas transmission compression.
(5) Underground natural gas storage.
(6) LNG storage.
(7) LNG import and export.
(8) Natural gas distribution. The operator must report each source in the aggregate for pipelines and for Metering and Regulating (M&R) stations.

(b) The operator must report emissions separately for standby equipment.

(c) The operator must report activity data for each aggregated source type as follows:

(1) Count of natural gas pneumatic high bleed devices.
(2) Count of natural gas pneumatic low bleed devices.
(3) Count of natural gas driven pneumatic pumps.
(4) For each acid gas removal unit the operator must report the following:

(A) Total volume of natural gas flow into the acid gas removal unit.
(B) Total volume of natural gas flow out of the acid gas removal unit.
(C) Volume weighted CO_2 content of natural gas into the acid gas removal unit.

(5) For each dehydrator unit the operator must report the following:

(A) Glycol dehydrators:

1. Glycol dehydrator feed natural gas flow rate.
2. Glycol dehydrator absorbent circulation pump type.
3. Glycol dehydrator absorbent circulation rate.
4. Whether stripper gas is used in glycol dehydrator.
5. Whether a flash tank separator is used in glycol dehydrator.

(B) Desiccant dehydrators:

1. The number of desiccant dehydrators operated.

(6) Count of wells vented to the atmosphere for liquids unloading for each field in the basin.

(7) Count of wells venting during well completions for each field in the basin.

(A) Number of conventional completions.
(B) Number of completions involving hydraulic fracturing.

(8) Count of wells venting during well workovers for each field in the basin.

(A) Number of conventional well workovers involving well venting to the atmosphere.
(B) Number of unconventional well workovers involving well venting to the atmosphere.

(9) For each compressor blowdown vent stack the operator must report the following for each compressor:

(A) Type of compressor whether reciprocating or centrifugal.
(B) Compressor capacity in horse powers.
(C) Volume of gas between isolation valves.
(D) Number of blowdowns per year.

(10) For each estimate of gas emitted from liquids sent to atmospheric tank using E&P Tank, the operator must report the following:

(A) Immediate upstream separator temperature and pressure.
(B) Sales oil API gravity.
(C) Estimate of individual tank or tank battery capacity in barrels.
(D) Oil, hydrocarbon condensate and water sent to tank(s) in barrels.
(E) Control measure: either vapor recovery system or flaring of tank vapors.

(11) For tank emissions identified using optical gas imaging instrument per section 95154(a) of this article, the operator must report the following for each tank:

(A) Immediate upstream separator temperature and pressure.
(B) Sales oil API gravity.
(C) Tank capacity in barrels.
(D) Tank throughput in barrels.
(E) Control measure: either vapor recovery system or flaring of tank vapors.
(F) Optical gas imagining instrument used.
(G) Meter used for measuring emissions.
(H) List of emissions sources routed to the tank.

(12) For well testing, the operator must report the following for each field in the basin:

(A) Number of wells tested in reporting period.
(B) Average gas to oil ratio for each field.
(C) Average flow rate during testing for each field.
(D) Average number of days the well is tested.
(E) Whether the hydrocarbons produced during testing are vented or flared.

(13) For associated natural gas venting, the operator must report the following for each field in the basin:

(A) Number of wells venting or flaring associated natural gas in reporting period.
(B) Average gas to oil ratio for each field.
(C) Average volume of oil produced per well per field.
(D) Whether the associated natural gas is vented or flared.

(14) For flare stacks, the operator must report the following for each flare:

(A) Whether the flare has a continuous flow monitor.
(B) If using engineering estimation methods, identify sources of emissions going to the flare.
(C) Whether the flare has a continuous gas analyzer.
(D) Identify the proportion of total natural gas to pure hydrocarbon stream being sent to the flare annually for the reporting period.
(E) Flare combustion efficiency.

(15) For well venting for liquids unloading, the operator must report the following by field, basin, and well tubing size:

(A) Number of wells being unloaded for liquids in reporting year.
(B) Average number of unloading(s) per well per reporting year.
(C) Average volume of natural gas produced per well per reporting year during liquids unloading.

(16) For well completions and workovers, the operator must report the following for each field in the basin:

(A) Number of wells completed (worked over) in reporting year.
(B) Average number of days required for completion (workover).
(C) Average volume of natural gas produced per well per reporting year during well completion (workover).

(17) For compressor wet seal degassing vents, the operator must report the following for each degassing vent:

(A) Number of wet seals connected to the degassing vent.
(B) Number of compressors whose wet seals are connected to the degassing vent.
(C) Total throughput of compressors whose wet seals are connected to the degassing vent.
(D) Type of meter used for making measurements.
(E) Whether emissions estimate is based on a continuous or one time measurement.
(F) Total time the compressor(s) associated with the degassing vent stack is operating. Sum the hours of operation if multiple compressors are connected to the vent stack.
(G) Proportion of vent gas recovered for fuel gas or sent to a flare.

(18) For reciprocating compressor rod packing, the operator must report the following per rod packing:

(A) Total throughput of the reciprocating compressor whose rod packing emissions is being reported.
(B) Total time in hours the reciprocating compressor is in operating mode.
(C) Whether or not the rod packing case is connected to an open ended line.
(D) If rod packing is connected to an open ended line, report type of device used for measurement of emissions.
(E) If rod packing is not connected to an open ended vent line, report the locations from where the emissions from the rod packing are detected.

(19) For fugitive emissions sources using emission factors for estimating emissions, the operator must report the following:

(A) Component count for each fugitive emissions source.
(B) CH_4 and CO_2 in produced natural gas for onshore petroleum and natural gas production.

(20) For EOR injection pump blowdown, the operator must report the following per pump:

(A) Pump capacity.
(B) Volume of gas between isolation valves.
(C) Number of blowdowns per year.
(D) Supercritical phase EOR injection gas density.

(21) For hydrocarbon liquids dissolved CO_2, the operator must report the following for each field in the basin:

(A) Volume of crude oil produced.

(22) For produced water dissolved CO_2 the operator must report the following for each field in the basin:

(A) Volume of produced water produced.

(d) Minimum, maximum and average throughput for each operation listed in paragraphs (a)(1) through (a)(8) of this section.

(e) For offshore petroleum and natural gas production facilities, the number of connected wells, and whether the wells are producing oil, gas, or both.

(f) The operator must report emissions separately for portable equipment for the following source types: drilling rigs, dehydrators, compressors, electrical generators, steam boilers, and heaters.

(1) Aggregate emissions by source type.
(2) Report count of each source type.

NOTE: Authority cited: Sections 39600, 39601, 39607, 39607.4, 41511, 38510, and 38530, Health and Safety Code. Reference: Sections 39600, 41511, and 38530, Health and Safety Code.

§ 95157. Records That Must be Retained.

In addition to the information required by 40 CFR §98.3(g), the operator must retain the following records according to the recordkeeping requirements of section 95105 of this article:

(a) Dates on which measurements were conducted.

(b) Results of all emissions detected and measurements.

(c) Calibration reports for detection and measurement instruments used.

(d) Inputs and outputs of calculations or emissions computer model runs used for engineering estimation of emissions.

NOTE: Authority cited: Sections 39600, 39601, 39607, 39607.4, 41511, 38510, and 38530, Health and Safety Code. Reference: Sections 39600, 41511, and 38530, Health and Safety Code.

§ 95158. Default Emission Factor Tables.

Table 1. Default Whole Gas Emission Factors for Onshore Production

Onshore production	*Emission Factor (scf/hour/ component)*
Population Emission Factors--All Components, Gas Service	
Valve	0.08
Connector.	0.01
Open-ended Line	0.04
Pressure Relief Valve	0.17
Low-Bleed Pneumatic Device Vents	2.75
Gathering Pipelines[1]	2.81
CBM Well Water Production[2]	0.11
Population Emission Factors--All Components, Light Crude Service[3]	
Valve	0.04
Connector.	0.01
Open-ended Line	0.04
Pump	0.01
Other[5]	0.24
Population Emission Factors--All Components, Heavy Crude Service[4]	
Valve	0.04
Connector	0.01
Open-ended Line	0.04
Pump	0.01
Other[5]	0.24
Valve	0.001
Flange	0.001
Connector (other)	0.0004
Open-ended Line	0.01
Other[5]	0.003

[1] Emission Factor is in units of "scf/hour/mile."
[2] Emission Factor is in units of "scf methane/gallon," in this case the operating factor is "gallons/year" and do not multiply by methane content.
[3] Hydrocarbon liquids greater than or equal to 20*API are considered "light crude."
[4] Hydrocarbon liquids less than 20*API are considered "heavy crude."
[5] "Others" category includes instruments, loading arms, pressure relief valves, stuffing boxes, compressor seals, dump lever arms, and vents.

Table 2. Default Total Hydrocarbon Emission Factors for Processing

Processing	*Before de-methanizer emission factor (scf/hour/ component)*	*After de-methanizer Emission factor (scf/hour/ component)*
Leaker Emission Factors--Reciprocating Compressor Components, Gas Service		
Valve	15.88	18.09
Connector.	4.31	9.10
Open-ended Line	17.90	10.29
Pressure Relief Valve	2.01	30.46
Meter	0.02	48.29
Leaker Emission Factors--Centrifugal Compressor Components, Gas Service		
Valve	0.67	2.51
Connector.	2.33	3.14
Open-ended Line	17.90	16.17
Dry Seal	105	105
Leaker Emission Factors--Other Components, Gas Service		
Valve		6.42
Connector		5.71
Open-ended Line		11.27
Pressure Relief Valve		2.01
Meter		2.93
Population Emission Factors--Other Components, Gas Service		
Gathering Pipelines[1]		2.81

[1] Emission Factor is in units of "scf/hour/mile."

Table 3. Default Methane Emission Factors for Transmission

Transmission	*Emission Factor (scf/hour/ component)*
Leaker Emission Factors--All Components, Gas Service	
Connector	2.7
Block Valve	10.4
Control Valve	3.4
Compressor Blowdown Valve	543.5
Pressure Relief Valve	37.2
Orifice Meter	14.3
Other Meter	0.1
Regulator	9.8
Open-ended Line	21.5
Population Emission Factors--Other Components, Gas Service	
Low-Bleed Pneumatic Device Vents	2.57

Table 4. Default Methane Emission Factors for Underground Storage

Underground Storage	*Emission Factor (scf/hour/ component)*
Leaker Emission Factors--Storage Station, Gas Service	
Connector	0.96
Block Valve	2.02
Control Valve	3.94
Compressor Blowdown Valve	66.15
Pressure Relief Valve	19.80
Orifice Meter	0.46
Other Meter	0.01
Regulator	1.03
Open-ended Line	6.01
Population Emission Factors--Storage Wellheads, Gas Service	
Connector	0.01
Valve	0.10
Pressure Relief Valve	0.17
Open-ended Line	0.03
Population Emission Factors--Other Components, Gas Service	
Low-Bleed Pneumatic Device Vents	2.57

Table 5. Default Methane Emission Factors for Liquefied Natural Gas (LNG) Storage

LNG Storage	*Emission Factor (scf/hour/ component)*
Leaker Emission Factors--LNG Storage Components, LNG Service	
Valve	1.19
Pump Seal	4.00
Connector	0.34
Other[1]	1.77
Population Emission Factors--LNG Storage Compressor, Gas Service	
Vapor Recovery Compressor	6.81

[1] "Other" equipment type should be applied for any equipment type other than connectors, pumps, or valves.

Table 6. Default Methane Emission Factors for LNG Terminals

LNG Terminals	*Emission Factor (scf/hour/ component)*
Leaker Emission Factors--LNG Storage Components, LNG Service	
Valve	1.19
Pump Seal	4.00
Connector	0.34
Other	1.77
Population Emission Factors-- LNG Terminals Compressor, Gas Service	
Vapor Recovery Compressor	6.81

Table 7. Default Methane Emission Factors for Distribution

Distribution		*Emission Factor (scf/hour/ component)*
Leaker Emission Factors--Above Grade M&R Stations Components, Gas Service		
	Connector	1.69
	Block Valve	0.557
	Control Valve	9.34
	Pressure Relief Valve	0.270
	Orifice Meter	0.212
	Regulator	0.772
	Open-ended Line	26.131
Population Emission Factors--Below Grade M&R Stations Components, Gas Service[1]		
	Below Grade M&R Station, Inlet Pressure >300 psig	1.30
	Below Grade M&R Station, Inlet Pressure 100 to 300 psig	0.20
	Below Grade M&R Station, Inlet Pressure <100 psig	0.10
Population Emission Factors--Distribution Mains, Gas Service[2]		
	Unprotected Steel	12.58
	Protected Steel	0.35
	Plastic	1.13
	Copper	27.25
Population Emission Factors--Distribution Services, Gas Service[2]		
	Unprotected Steel	0.19
	Protected Steel	0.02
	Plastic	0.001
	Copper	0.03

[1] Emission Factor is in units of "scf/hour/station."
[2] Emission Factor is in units of "scf/hour/service."

Table 8. Default Nitrous Oxide Emission Factors for Gas Flaring

		Emission Factor (metric tons/MMscfgas production or receipts)
Population Emission Factors--Gas Flaring		
	Gas Production	5.90E-07
	Sweet Gas Processing	7.10E-07
	Sour Gas Processing	1.50E-06
	Conventional Oil Production[1]	1.00E-04
	Heavy Oil Production[2]	7.30E-05

[1] Emission Factor is in units of "metric tons/barrel conventional oil production."
[2] Emission Factor is in units of "metric tons/barrel heavy oil production."

NOTE: Authority cited: Sections 39600, 39601, 39607, 39607.4, 41511, 38510, and 38530, Health and Safety Code. Reference: Sections 39600, 41511, and 38530, Health and Safety Code.

STATE OF CALIFORNIA

California Environmental Protection Agency

AIR RESOURCES BOARD

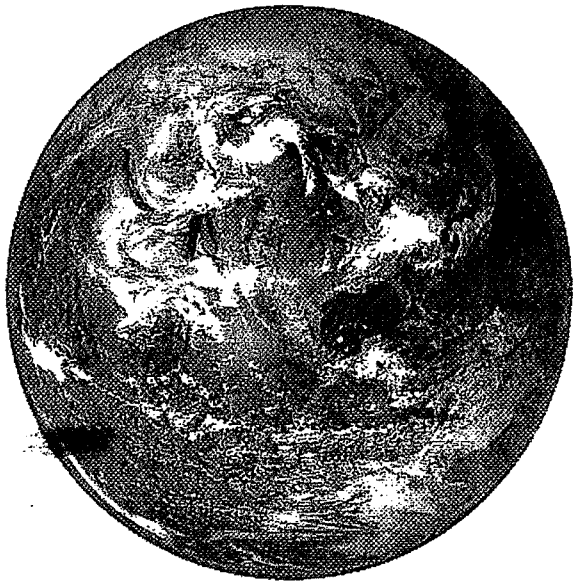
ATTACHMENT B

SUPPLEMENTAL MATERIALS DOCUMENT FOR

STAFF REPORT: INITIAL STATEMENT OF REASONS FOR RULEMAKING

REVISIONS TO THE

REGULATION FOR MANDATORY REPORTING OF GREENHOUSE GAS EMISSIONS PURSUANT TO THE CALIFORNIA GLOBAL WARMING SOLUTIONS ACT OF 2006 (ASSEMBLY BILL 32)



Planning and Technical Support Division
Emission Inventory Branch

October 28, 2010

ATTACHMENT B

Underline/Strikeout Display of

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

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

This document shows amendments to the currently enacted Regulation for the Mandatory Reporting of Greenhouse Gas Emissions (Division 3, Chapter 1, Subchapter 10, Article 2, sections 95100 to 95133, title 17, California Code of Regulations). The amendments, including additions and deletions, are set forth in Attachment A of the Staff Report: Initial Statement of Reasons, released October 27, 2010. The proposed amendments are shown in underline to indicate additions and ~~strikeout~~ to indicate deletions.

Amend Division 3, Chapter 1, Subchapter 10, Article 2, sections 95100, 95101, 95102, 95103, 95104, 95105, 95106, 95107, 95108, 95109, 95110, 95111, 95112, 95113, 95114, 95115, 95130, 95131, 95132, and 95133, title 17, California Code of Regulations; repeal section 95125, title 17, California Code of Regulations; and add new sections 95100.5, 95116, 95117, 95118, 95119, 95120, 95121, 95122, 95123, 95129, 95150, 95151, 95152, 95153, 95154, 95155, 95156, 95157, and 95158, title 17, California Code of Regulations to read as follows:

Article 2: Mandatory Greenhouse Gas Emissions Reporting

Subarticle 1. General Requirements for Greenhouse Gas Reporting

§ 95100. ~~Purpose.~~ Table of Contents

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§ 95100.5. Purpose and Scope

(a) The purpose of this article is to ~~require the~~establish mandatory greenhouse gas (GHG) reporting ~~and verification of greenhouse gas emissions from specified greenhouse gas emissions sources~~, verification, and other requirements for operators of certain facilities that directly emit GHGs, suppliers of certain fuels and carbon dioxide, electric power entities, verifiers of GHG emissions data reports and offset project data reports submitted pursuant to the Cap-and-Trade Regulation, and verification bodies. This article is designed to meet the requirements of section 38530 of the Health and Safety Code, and to support GHG regulatory programs of the California Air Resources Board.

~~NOTE: Authority cited: Sections 39600, 39601, 41511, 38510, and 38530, Health and Safety Code. Reference: Sections 39600, 41511, and 38530, Health and Safety Code.~~

~~**§ 95101. Applicability.**~~

~~(a)~~ (b) *Organization of this Article.* Subarticle 1 specifies general requirements for the reporting of ~~greenhouse gas~~GHG emissions that apply to all ~~facilities~~reporting entities listed ~~below~~ in section ~~(b).~~95101. Subarticle 2 specifies reporting requirements and calculation methods for specific types of facilities and entities. Subarticle 3 specifies ~~calculation methods that are applicable to multiple types of facilities~~additional requirements for reported data, including procedures for the substitution for missing data. Subarticle 4 specifies ~~greenhouse gas emissions data report~~ verification requirements ~~and the~~for GHG emissions data reports, requirements for those who ~~perform greenhouse gas emission verifications~~provide verification services for GHG reporting entities, and accreditation requirements for verifiers of emissions data reports and offset project data reports. Subarticle 5 specifies reporting requirements and calculation methods for petroleum and natural gas production, processing, and storage facilities.

(c) *U.S. EPA GHG Reporting Rule.* This article incorporates various provisions of title 40, Code of Federal Regulations (CFR), Part 98. These provisions are a portion of the U.S. Environmental Protection Agency (U.S. EPA) Final Rule on Mandatory Reporting of Greenhouse Gases. Unless otherwise specified, references in this article to 40 CFR Part 98 are to those requirements promulgated by U.S. EPA on October 30, 2009, July 12, 2010, September 22, 2010, and October 7, 2010.

~~(b)~~ (d) Except as otherwise specifically provided ~~in section 95101(c) and section 95103(e), this article applies~~:

(1) Wherever the term "Administrator" is used in the federal rules referred to in this article, the term "Executive Officer of the California Air Resources Board" or "Executive Officer" shall be substituted.
(2) Wherever the term "EPA" is used in the federal rules referred to in this article, the term "California Air Resources Board" or "ARB" shall be substituted.

(3) In cases where the owner and operator of a facility or a supplier are not the same party, the operator is responsible for compliance with this article.

NOTE: Authority cited: Sections 39600, 39601, 39607, 39607.4, 41511, 38510, and 38530, Health and Safety Code. Reference: Sections 39600, 41511, and 38530, Health and Safety Code.

§ 95101. Applicability.

(a) *General Applicability.*

(1) This article applies to the following entities:

(~~1~~A) Operators of ~~cement plants~~facilities located in California and included in 40 CFR §98.2(a)(1)-(3);

(~~2~~B) ~~Operators of petroleum refineries in California that emit greater than or equal to 25,000 metric tonnes of CO_2 in any calendar year after 2007 from the combination of stationary combustion and process sources;~~Suppliers of fuels or carbon dioxide provided for consumption within California that are included in 40 CFR §98.2(a)(4) or specified below in subsection (c);

(~~3~~C) ~~Operators of hydrogen plants in California that emit greater than or equal to 25,000 metric tonnes of CO_2 in any calendar year after 2007 from the combination of stationary combustion sources and hydrogen production processes;~~ Electric power entities as specified below in subsection (d); and,

(4D) Operators of ~~electricity generating facilities that are located in California or operated by a retail provider as defined in section 95102(a), that individually have a nameplate generating capacity greater than or equal to 1 megawatt (MW), and that emit greater than or equal to 2,500 metric tonnes of CO_2 in any calendar year after 2007 from electricity generating activities, including hybrid generating facilities;~~petroleum or natural gas systems as specified below in subsection (e).

~~(5) Retail providers as defined in section 95102(a);~~

~~(6) Marketers as defined in section 95102(a);~~

~~(7) Operators of cogeneration facilities that are located in California or operated by a retail provider as defined in section 95102(a) that individually have a nameplate generating capacity greater than or equal to 1 megawatt (MW), and that emit greater than or equal to 2,500 metric tonnes of CO_2 in any calendar year after 2007 from electricity generating activities;~~

~~(8) Operators of other facilities in California that emit greater than or equal to 25,000 metric tonnes per year of CO_2 from stationary combustion sources in any calendar year after 2007.~~

(2) Any reporting entity that fits into one or more of the categories in subsection (a)(1) above for calendar year 2011 or later must submit an emissions data report for that year and for subsequent calendar years, except as provided in the report cessation provisions of subsection (h) of this section. The emissions data report must cover all source categories and GHGs for which

calculation methods are provided or referenced in this article for the reporting entity. Except as otherwise specified in this article, the report must be compiled using the methods specified by source category in 40 CFR Part 98.

(3) *Verifiers and Verification Bodies.* In addition to the reporting entities specified in subsection (a)(1) above, this article contains requirements for entities acting as verification bodies and individuals acting as third party verifiers of emissions data reports and offset project data reports. These requirements are specified in sections 95130 through 95133 of this article.

(b) *Calculating GHG Emissions Relative to Reporting Thresholds.* For industrial sectors for which an emissions-based applicability threshold is specified in 40 CFR §98.2, the reporting entity must apply a threshold of 10,000 metric tons of CO_2e for reporting under this article. Operators of facilities and suppliers must calculate their emissions using the requirements of 40 CFR §98.2(b)-(q), using a 10,000 metric tons of CO_2e threshold to determine if reporting is required. For purposes of determining reporting applicability for a 10,000 metric tons of CO_2e threshold, combustion and process emissions of CO_2, CH_4 and N_2O must be included, but fluorinated gases may be excluded.

(1) Facilities with stationary combustion emissions are included according to the requirements of 40 CFR 98.2(a)(3), except that the thresholds for reporting in California are 10,000 metric tons of CO_2e and an aggregate maximum heat input capacity of 12 mmBtu/hr or greater.
(2) Notwithstanding 40 CFR §98.2(b)(2), operators of facilities and suppliers must include emissions of CO_2 from the combustion of biomass and other biofuels when determining applicability relative to thresholds for emissions reporting and cessation of reporting.
(3) Operators of geothermal generating units must report when total facility emissions of CO_2 and CH_4 equal or exceed 10,000 metric tons of CO_2e.

(c) *Fuel and CO_2 Suppliers.* The suppliers listed below, as defined in section 95102(a), are required to report under this article when they import and/or deliver an annual quantity of products that, when completely combusted or oxidized, 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:

(1) Position holders at terminals and refineries delivering petroleum products and/or biomass-derived fuels, as described in section 95121;
(2) Enterers that import petroleum products and/or biomass-derived fuels outside the bulk transfer/terminal system, as described in section 95121;
(3) Producers of biomass-derived fuels, as described in section 95121;
(4) All refiners that produce liquefied petroleum gas, without regard to product quantities, as described in section 95121;
(5) Operators of interstate pipelines delivering natural gas, as described in section 95122;

(6) California consignees of liquefied petroleum gas, as described in section 95122;
(7) Local distribution companies who are public utility gas corporations or publicly-owned natural gas utilities delivering natural gas, as described in section 95122;
(8) Operators of intrastate pipelines delivering natural gas as described in section 95122;
(9) All natural gas liquid fractionators, without regard to product quantities produced, as described in section 95122;
(10) All producers of carbon dioxide without regard to product quantity produced, and importers of carbon dioxide with annual bulk imports into California of 10,000 metric tons or more, as described in section 95123.

(d) *Electric Power Entities.* The entities listed below are required to report under this article:

(1) Electricity importers and exporters, as defined in section 95102(a);
(2) Retail providers, including multi-jurisdictional retail providers, as defined in section 95102(a);
(3) California Department of Water Resources (DWR);
(4) Western Area Power Administration (WAPA);
(5) Bonneville Power Administration (BPA).

(e) *Petroleum and Natural Gas Systems.* The facilities listed below, as specified in section 95150, are required to report under this article when their stationary combustion and process emissions equal or exceed 10,000 metric tons of CO_2e:

(1) Offshore petroleum and natural gas production facilities;
(2) Onshore petroleum and natural gas production facilities, when the reporting entity meets the requirements of section 95151(a)(1);
(3) Onshore natural gas processing plants;
(4) Onshore natural gas transmission compression facilities;
(5) Underground natural gas storage facilities;
(6) Liquefied natural gas storage facilities;
(7) Liquefied natural gas import and export facilities;
(8) Natural gas distribution facilities.

~~(e)~~ (f) *Exclusions.* This article does not apply to, and greenhouse gas emissions reporting is not required for:

(1) Electricity generating facilities that are solely powered by nuclear, hydroelectric, wind, or solar energy, unless on-site stationary combustion and process emissions equal or exceed 10,000 metric tons of CO_2e;
~~(2) Portable equipment;~~
~~(3)~~ (2) Generating units designated as backup or emergency generators in a permit issued by an air pollution control district or air quality management district;

(3) Fire suppression systems and equipment;
~~(4) Hospitals with a North American Industry Classification System (NAICS) code starting with 62;~~
(4) Portable equipment, except where specifically required to report under 40 CFR Part 98 or this article;
(5) Primary and secondary schools with a NAICS code of 611110.

~~(d)~~ (g) *Demonstration of Nonapplicability.* The Executive Officer may request a demonstration from any operator, supplier, or entity ~~operating a facility to establish that a specified facility~~ that the operator, supplier, or entity does not meet one or more of the applicability criteria specified in ~~section 95101(b)~~this article. Such demonstration ~~shall~~must be provided to the Executive Officer within 20 ~~working~~ days of receipt of a written request ~~received from the Executive Officer~~.

(h) *Cessation of Reporting.* Except as otherwise specified below, a facility operator or supplier whose emissions fall below the applicable emissions reporting thresholds of this article and who wishes to cease annual reporting must comply with 40 CFR §98.2(i). The operator or supplier must provide the letter notifications specified in 40 CFR §98.2(i) to the address indicated in section 95103 of this article. For purposes of this article:

(1) Wherever 40 CFR §98.2(i)(1) states "25,000 metric tons of CO_2e per year," the phrase "10,000 metric tons of CO_2e per year" shall be substituted.
(2) Wherever 40 CFR §98.2(i)(2) states "15,000 metric tons of CO_2e per year," the phrase "5,000 metric tons of CO_2e per year" shall be substituted.
(3) In cases of permanent shutdown as specified in 40 CFR §98.2(i)(3), a reporter must submit an emissions data report for the year in which a facility or supplier's GHG-emitting processes and operations ceased to operate, and for the first full year of non-operation that follows.
(4) The verification requirements of this article do not apply to the first full year of non-operation following a permanent shutdown, but continue to apply to prior emissions data reports.

NOTE: Authority cited: Sections 39600, 39601, 39607, 39607.4, 41511, 38510, and 38530, Health and Safety Code. Reference: Sections 39600, 41511, and 38530, Health and Safety Code.

Subarticle 1~~.~~: General Requirements for ~~the Mandatory Reporting of~~ Greenhouse Gas ~~Emissions~~Reporting

§ 95102. Definitions.

(a) For the purposes of this article, the following definitions shall apply:

(1) ~~"Accuracy" means the closeness of the agreement between the result of the measurement and the true value of the particular quantity (or a reference value determined empirically using internationally accepted and traceable calibration materials and standard methods), taking into account both random and systematic factors.~~ "Absorbent circulation pump" means a pump commonly powered by natural gas pressure that circulates the absorbent liquid between the absorbent regenerator and natural gas contactor.

(2) "Acid gas" means hydrogen sulfide (H_2S) and carbon dioxide (CO_2) contaminants that are separated from sour natural gas by an acid gas removal.

(3) "Acid gas removal unit (AGR)" means a process unit that separates hydrogen sulfide and/or carbon dioxide from sour natural gas using liquid or solid absorbents or membrane separators.

(4) "Acid gas removal vent stack emissions" mean the acid gas separated from the acid gas absorbing medium (e.g., an amine solution) and released with methane and other light hydrocarbons to the atmosphere or a flare.

(5) "Additional" means, in the context of offset credits, greenhouse gas emission reduction or GHG removal enhancement activities, that result in greenhouse gas reduction or GHG removal enhancements, other than those activities required by law or regulation, any legally binding mandate, or any greenhouse gas reduction or GHG removal enhancement activities that would otherwise occur in a conservative business-as-usual scenario.

(6) ~~(2)~~ "Adverse verification ~~opinion~~statement" means a verification ~~opinion~~statement rendered by a verification body ~~stating~~attesting that the verification body cannot say with reasonable assurance that the submitted emissions data report is free of material misstatement~~, or that it cannot provide a qualifying statement that the emissions data report conforms to the requirements of this article~~.

(7) "Air injected flare" means a flare in which air is blown into the base of a flare stack to induce complete combustion of low Btu natural gas (i.e., high non-combustible component content.)

(8) "Allowance" means, unless the plain meaning of the word indicates otherwise, a limited tradable authorization to emit up to one metric ton of carbon dioxide equivalent.

(9) ~~(3)~~ "Annual" means with a frequency of once a year; unless otherwise noted, annual events such as reporting requirements will be based on the calendar year.

(10) "API" means the American Petroleum Institute.

(11) ~~(4)~~ "AQMD/APCD" or "air district" means air quality management district or air pollution control district.

(12) ~~(5)~~ "ARB" means the California Air Resources Board.

(13) "Artificial island" is a plot of land or other structure constructed on a body of water to support onshore petroleum or natural gas production.

(14) ~~(6)~~ "Asphalt" means a dark brown ~~or black cementitious material (solid or liquid) of which the main constituents are bitumins that occur naturally or as a residue of petroleum refining~~ to-black cement-like material obtained by petroleum processing and containing bitumens as the predominant component. It includes crude asphalt as well as the following finished products: cements, fluxes, the asphalt content of emulsions (exclusive of water), and petroleum distillates blended with asphalt to make cutback asphalts.

~~(7) "Asphalt blowing" means the process by which air is blown through asphalt flux to change the softening point and penetration rate.~~

(15) ~~(8)~~ "Asset ~~-~~controlling supplier" means any entity that owns or operates electricity generating facilities or serves as an exclusive marketer for certain generating facilities even though it does not own them~~.~~, and is assigned a supplier-specific identification number and specified source emission factor by ARB for the wholesale electricity procured from its system and imported into California. Asset controlling suppliers include Bonneville Power Administration (BPA) and the two multi-jurisdictional retail providers in California: PacifiCorp and Sierra Pacific Power Company.

~~(9) "Asset owning supplier" means any entity owning electricity generating facilities that delivers electricity to a transmission or distribution line.~~

(16) "Assigned emissions level" means an amount of emissions, in CO_2e, assigned to the reporting entity by the Executive Officer in the case of a non submitted/non-verified emissions data report or following the issuance of an adverse verification statement.

(17) ~~(10)~~ "Associated gas" or "produced gas" means a natural gas that is produced from gas wells or gas produced in association with the production of crude oil.

(18) "ASTM" means the American Society of Testing and Materials.

(19) "Authorized project designee" means an entity authorized by an Offset Project Operator to act on behalf of the Offset Project Operator.

(20) "Balancing authority" means the responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a balancing authority area, and supports interconnection frequency in real time.

(21) "Balancing authority area" means the collection of generation, transmission, and loads within the metered boundaries of a balancing authority. A balancing authority maintains load-resource balance within this area.

(22) ~~(11)~~ "Barrel" means a volume equal to 42 U.S. gallons.

~~(12) "Best available data and methods" means ARB methods for emissions calculations set forth in this article where reasonably feasible; or facility fuel use and other facility process data used in conjunction with ARB provided emission factors and other data; or other generally accepted methods for calculating greenhouse gas emissions.~~

(23) "Bias" means systematic error, resulting in measurements that will be either consistently low or high relative to the reference value.

(24) "Biodiesel" means a diesel fuel substitute produced from nonpetroleum renewable resources that meet the registration requirements for fuels and fuel additives established by the U.S. Environmental Protection Agency under section 211 of the Clean Air Act. It includes biodiesel that is all of the following:

(A) Registered as a motor vehicle fuel or fuel additive under 40 CFR Part 79;

(B) A mono-alkyl ester;

(C) Meets American Society for Testing and Material designation ASTM D 6751-08 (*Standard Specification for Biodiesel Fuel Blendstock (B100) for Middle Distillate Fuels, 2008*);

(D) Intended for use in engines that are designated to run on conventional diesel fuel; and

(E) Derived from nonpetroleum renewable resources.

(25) "Biogenic portions of CO_2 emissions" means carbon dioxide emissions generated as the result of biomass combustion from combustion units.

(26) ~~(13)~~ "Biomass" means non-fossilized and biodegradable organic material originating from plants, animals and micro-organisms, including products, byproducts, residues and waste from agriculture, forestry and related industries as well as the non-fossilized and biodegradable organic fractions of industrial and municipal wastes, including gases and liquids recovered from the decomposition of non-fossilized and biodegradable organic material. For the purpose of this article, biomass includes both California Renewable Portfolio Standard (RPS) eligible and non-eligible biomass as defined by the California Energy Commission.

(27) ~~(14)~~ "Biomass-derived fuels" or "biomass fuels" or "biofuels" or "biomass-based fuels" means fuels derived ~~entirely~~ from biomass.

(28) "Blendstocks" are petroleum products used for blending or compounding into finished motor gasoline. These include RBOB (reformulated blendstock for oxygenate blending) and CBOB (conventional blendstock for oxygenate blending), but exclude oxygenates, butane, and pentanes plus.

(29) "Blowdown" means the act of emptying or depressurizing a vessel. This may also refer to the discarded material such as blowdown water from a boiler or cooling tower.

(30) "Blowdown vent stack emissions" mean natural gas released due to maintenance and/or blowdown operations including compressor blowdown and emergency shut-down (ESD) system testing.

(31) "Bone dry short ton" means an amount of material that weighs 2,000 pounds at zero percent moisture content.

(32) ~~(15)~~ "Bottom ash" means ash that collects at the bottom of a combustion chamber.

(33) ~~(16)~~ "Bottoming cycle ~~plant~~" means a type of cogeneration ~~facility~~system in which the energy input to the system is first applied to a useful thermal energy application or process, and at least some of the reject heat emerging from the application or process is then used for ~~power~~electricity production.

(34) ~~(17)~~ "British ~~Thermal Unit~~thermal unit" or "Btu" means the quantity of heat required to raise the temperature of one pound of water by one degree Fahrenheit at about 39.2 degrees Fahrenheit.

(35) "Bulk transfer/terminal system" means a fuel distribution system consisting of refineries, pipelines, vessels, and terminals.

(36) ~~(18)~~ "Busbar" means ~~the~~a power conduit of ~~an~~a facility with electricity generating ~~facility~~units that serves as the starting point for the electricity transmission system.

(37) "Business-as-usual scenario" means the set of conditions reasonably expected to occur within the offsets project boundary in the absence of the financial incentives provided by offset credits, taking into account all current laws and regulations, as well as current economic and technological trends.

(38) ~~(19)~~ "Butane" ~~means a normally gaseous~~or "n-Butane" is a paraffinic straight-chain ~~or branch chain hydrocarbon extracted from natural gas or refinery fuel gas streams and is represented by the chemical formula C_4H_{10}. Butane includes normal butane and refinery grade butane.~~ hydrocarbon with molecular formula C_4H_{10}.

(39) ~~(20)~~ "Bypass dust" means discarded dust from the bypass system dedusting unit of suspension preheater, precalciner and grate preheater kilns, consisting of fully calcined kiln feed material.

~~(21) "CAISO" means the California Independent System Operator.~~

~~(22) "CAISO integrated forward market" means the electric power market conducted by the CAISO that determines the best use of resources available while finding the least cost method of procuring required components.~~

~~(23) "CAISO markets" mean the CAISO real-time market and the CAISO integrated forward market.~~

~~(24) "CAISO real-time market" means the electric power market conducted by the CAISO where supplemental electric power is quickly bought or sold every ten minutes to accommodate power use just moments before it occurs.~~

(40) ~~(25)~~ "Calcination" means the thermal decomposition of carbonate minerals, such as calcium carbonate (the principal mineral in limestone) to form calcium oxide in a cement kiln.

(41) ~~(26)~~ "Calcine" means to heat a substance so that it oxidizes or reduces.

(42) ~~(27)~~ "Calendar year" means the time period from January 1 through December 31.

~~(28) "California Climate Action Registry" or "CCAR" means the entity established pursuant to former Health and Safety Code Section 42800 et seq.~~

~~(29) "California eligible renewable resource" means an electricity generating facility that the California Energy Commission has certified as an eligible renewable energy resource that may be used by a retail seller of electricity to satisfy its California Renewables Portfolio Standard Program procurement requirements, consistent with Public Utilities Code sections 399.11 through 399.16 and Public Resources Code sections 25740 through 25751.~~

(43) "Calibrated bag" means a flexible, non-elastic, anti-static bag of a calibrated volume that can be affixed to an emitting source such that the emissions inflate the bag to its calibrated volume.

(44) "Cap-and-Trade Regulation" or "Cap-and-Trade Program" means ARB's regulation establishing the California Cap on Greenhouse Gas Emissions and Market-Based Compliance Mechanisms set forth in title 17, California Code of Regulations, Chapter 1, Subchapter 10, article 5 (commencing with section 95800).

(45) "California consignee" means the person or entity in California to whom the shipment is to be delivered.

(46) ~~(30)~~ "California Energy Commission" or "CEC" means the California Energy Resources Conservation and Development Commission.

~~(31) "Capacity factor" means the amount of energy that an electricity generating facility actually generates compared to its maximum rated output over a given period of time, usually one year.~~

(47) ~~(32)~~ "Carbon dioxide" or "CO_2" means the most common of the six primary greenhouse gases, consisting on a molecular level of a single carbon atom and two oxygen atoms.

(48) ~~(33)~~ "Carbon dioxide equivalent"" or "CO_2 equivalent" or ""CO_2e"" means ~~a measure for comparing carbon dioxide with other GHGs, based on the quantity of those gases multiplied by the appropriate~~the number of metric tons of CO_2 emissions with the same global warming potential ~~(GWP) factor and commonly expressed~~ as one metric ~~tonnes of carbon dioxide equivalents ($MTCO_2e$)~~ton of another greenhouse gas.

(49) ~~(34)~~ "Catalyst" means a substance added to a chemical reaction, which facilitates or causes the reaction, and is not consumed by the reaction.

~~(35) "Catalyst coke" means carbon that is deposited on a catalyst, thus deactivating the catalyst.~~

~~(36) "Catalytic cracking" means a refinery process of breaking down larger, heavier, and more complex hydrocarbon molecules into simpler and lighter molecules. Catalytic cracking is accomplished by the use of a catalyst.~~

~~(37) "Catalytic reforming" means a refining process using controlled heat and pressure with catalysts to rearrange certain hydrocarbon molecules.~~

(50) ~~(38)~~ "Cement" means a building material that is produced by heating mixtures of limestone and other minerals or additives at high temperatures in a rotary kiln to form clinker, followed by cooling and grinding with blended additives. Finished cement is a powder used with water, sand and gravel to make concrete and mortar.

~~(39) "Cementitious product" means cement, cement kiln dust, cement clinker, clinker dust, fly ash, slag, and other pozzolans.~~

(51) ~~(40)~~ "Cement kiln dust" or "CKD" means the fine-grained, solid, highly alkaline waste removed from cement kiln exhaust gas by air pollution control devices. CKD consists of partly calcined kiln feed material and includes all dust from cement kilns and bypass systems including bottom ash and bypass dust.

(52) ~~(41)~~ "Cement plant" means an industrial structure, installation, plant, or building primarily engaged in manufacturing Portland, natural, masonry, pozzolanic, and other hydraulic cements, and typically identified by NAICS code 327310.

(53) "Centrifugal compressor" means any equipment that increases the pressure of a process natural gas by centrifugal action, employing rotating movement of the driven shaft.

(54) "Centrifugal compressor dry seals" means a series of rings around the compressor shaft where it exits the compressor case that operates mechanically under the opposing forces to prevent natural gas from escaping to the atmosphere.

(55) "Centrifugal compressor dry seals emissions" means natural gas released from a dry seal vent pipe and/or the seal face around the rotating shaft where it exits one or both ends of the compressor case.

(56) "Centrifugal compressor wet seal degassing venting emissions" means emissions that occur when the high-pressure oil barriers for centrifugal compressors are depressurized to release absorbed natural gas. High-pressure oil is used as a barrier against escaping gas in centrifugal compressor shafts. Very little gas escapes through the oil barrier, but under high pressure, considerably more gas is absorbed by the oil. The seal oil is purged of the absorbed gas (using heaters, flash tanks, and degassing techniques) and recirculated. The separated gas is commonly vented to the atmosphere.

(57) "Certification" or "certify" refers to the procedure in 40 CFR §98.4(c), as required for reports submitted to ARB under this article.

(58) "City gate" means a location at which natural gas ownership or control passes from one party to another, neither of which is the ultimate consumer. In this article, in keeping with common practice, the term refers to a point or measuring station at which a local gas distribution utility receives gas from a natural gas pipeline company or transmission system. Meters at the city gate station measure the flow of natural gas into the local distribution company system and typically are used to measure local distribution company system sendout to customers.

(59) ~~(42)~~ "Clinker" means the mass of fused material produced in a cement kiln from which finished cement is manufactured by milling and grinding.

(60) ~~(43)~~ "Coal" means all solid fuels classified as anthracite, bituminous, sub-bituminous, or lignite by the American Society for Testing and Materials Designation ASTM D388–05 "Standard Classification of Coals by Rank." (September 2005).

~~(44) "Coal-derived fuel" means any fuel, whether in a solid, liquid, or gaseous state, produced by the mechanical, thermal, or chemical processing of coal (e.g., pulverized coal, coal refuse, liquefied or gasified coal, washed coal, chemically cleaned coal, coal-oil mixtures, and coal-derived coke).~~

~~(45) "Cogeneration facility" means an industrial structure, installation, plant, building, or self-generation facility, which may include one or more cogeneration systems configured as either a topping cycle or bottoming cycle plant.~~

~~(46) "Cogeneration system" means individual cogeneration components including the prime mover (heat engine), generator, heat recovery, and electrical interconnection, configured into an integrated system that provides sequential generation of multiple forms of useful energy (usually mechanical and thermal), at least one form of which the facility consumes on-site or makes available to other users for an end-use other than electricity generation.~~

(61) "Coal bed methane" or "CBM" means natural gas which is extracted from underground coal deposits or "beds."

(62) "Cogeneration" means an integrated system that produces electric energy and useful thermal energy for industrial, commercial, or heating and cooling purposes, through the sequential or simultaneous use of the original fuel energy.

(63) "Cogeneration unit" means a unit that produces electric energy and useful thermal energy for industrial, commercial, or heating and cooling purposes, through the sequential [or simultaneous] use of the original fuel energy.

(64) ~~(47)~~ "Coke (petroleum)" means a solid residue consisting mainly of carbon which results from the cracking of petroleum hydrocarbons in processes such as coking and fluid coking. This includes catalyst coke deposited on a catalyst during the refining process which must be burned off in order to regenerate the catalyst.

~~(48) "Coke burn-off" means coke removal from the surface of a catalyst by combustion during catalyst regeneration.~~

(65) ~~(49)~~ "Combustion emissions" means greenhouse gas emissions occurring during the exothermic reaction of a fuel with oxygen.

(66) ~~(50)~~ "Combustion source" means a source of emissions resulting from combustion ~~emissions~~.

(67) "Commercial propane" means liquefied petroleum gas that has any mixture of gasses that can sustain combustion.

(68) "Compliance instrument" means an allowance, offset credit or sector-based offset credit. Each compliance instrument can be used to fulfill a compliance obligation equivalent to up to one metric ton of CO_2e.

(69) "Compliance obligation" means the quantity of verified reported emissions for which a covered entity must submit compliance instruments to ARB.

(70) "Compliance offset protocol" means an offset protocol adopted by the Board.

(71) "Compliance period" means the three-year period for which the compliance obligation is calculated for covered entities pursuant to the Cap-and-Trade Regulation.

(72) "Component" for the purposes of sections 95150 to 95158 of this article means each metal to metal joint or seal of non-welded connection separated by a compression gasket, screwed thread (with or without thread sealing compound), metal to metal compression, or fluid barrier through which natural gas or liquid can escape to the atmosphere.

(73) "Compressor" means any machine for raising the pressure of a natural gas by drawing in low pressure natural gas and discharging significantly higher pressure natural gas.

(74) "Condensate" means hydrocarbon and other liquid separated from natural gas that condenses due to changes in the temperature, pressure, or both, and remains liquid at storage conditions, includes both water and hydrocarbon liquids.

(75) "Conservative" means, in the context of offsets, utilizing project baseline assumptions, emission factors, and methodologies that are more likely than not to understate net GHG reductions or GHG removal enhancements for an offset project to address uncertainties affecting the calculation or measurement of GHG reductions or GHG removal enhancements.

(76) ~~(51)~~ "Conflict of interest" means a situation in which, because of financial or other activities or relationships with other persons or organizations, a person or body is unable or potentially unable to render an impartial verification ~~opinion~~statement of a potential client's greenhouse gas

emissions data report, or the person or body's objectivity in performing verification services is or might be otherwise compromised.

(77) "Consignee" means the same as "California consignee."

(78) ~~(52)~~ "Continuous emissions monitoring system" or "CEMS" means the total equipment required to obtain a continuous measurement of a gas concentration or emission rate from combustion or industrial processes.

~~(53) "Conveying system" means a device for transporting materials from one piece of equipment or location to another location within a facility. Conveying systems include but are not limited to the following: feeders, belt conveyors, bucket elevators and pneumatic systems.~~

(79) "Conventional wells" mean gas wells in producing fields that do not employ hydraulic fracturing to produce commercially viable quantities of natural gas.

(80) ~~(54)~~ "Cracking" means the process of breaking down larger molecules into smaller molecules, utilizing catalysts and/or elevated temperatures and pressures.

(81) ~~(55)~~ "Crude oil"" means a mixture of hydrocarbons that exists in the liquid phase ~~and that is found~~ in natural underground reservoirs and remains liquid at atmospheric pressure after passing through surface separating facilities. Depending on the characteristics of the crude stream, it may also include any of the following:

(A) Small amounts of hydrocarbons that exist in gaseous phase in natural underground reservoirs but are liquid at atmospheric conditions (temperature and pressure) after being recovered from oil well (casing-head) gas in lease separators and are subsequently commingled with the crude stream without being separately measured. Lease condensate recovered as a liquid from natural gas wells in lease or field separation facilities and later mixed into the crude stream is also included.

(B) Small amounts of non-hydrocarbons, such as sulfur and various metals.

(C) Drip gases, and liquid hydrocarbons produced from tar sands, oil sands, gilsonite, and oil shale.

(D) Petroleum products that are received or produced at a refinery and subsequently injected into a crude supply or reservoir by the same refinery owner or operator.

Liquids produced at natural gas processing plants are excluded. Crude oil is refined to produce a wide array of petroleum products, including heating

oils; gasoline, diesel and jet fuels; lubcirants; asphalt; ethane, propane and butane; and many other products used for their energy or chemical content.

(82) "Customer" means a purchaser of electricity not for the purposes of retransmission or resale.

(83) "Data year" means the calendar year in which emissions occurred.

(84) "Delivered electricity" means electricity that was distributed from a PSE and received by a PSE or electricity that was generated, transmitted, and consumed.

(85) ~~(56)~~ "De minimis" means those emissions reported for a source or sources that are calculated using ~~alternative~~alternatives methods selected by the operator, subject to the limits specified in section 95103(~~a~~)(~~6~~i).

(86) "Dehydrator" means a device in which a liquid absorbent (including desiccant, ethylene glycol, diethylene glycol, or triethylene glycol) directly contacts a natural gas stream to absorb water vapor.

(87) "Dehydrator vent stack emissions" means natural gas released from a natural gas dehydrator system absorbent (typically glycol) reboiler or regenerator, including stripping natural gas and motive natural gas used in absorbent circulation pumps.

(88) "Delayed coking" means a process by which heavier crude oil fractions are thermally decomposed under conditions of elevated temperature and pressure to produce a mixture of lighter oils and petroleum coke.

(89) "De-methanizer" means the natural gas processing unit that separates methane rich residue gas from the heavier hydrocarbons (e.g., ethane, propane, butane, pentane-plus) in feed natural gas stream.

(90) "Desiccant" means a material used in solid-bed dehydrators to remove water from raw natural gas by adsorption. Desiccants include activated alumina, palletized calcium chloride, lithium chloride and granular silica gel material. Wet natural gas is passed through a bed of the granular or pelletized solid adsorbent in these dehydrators. As the wet gas contacts the surface of the particles of desiccant material, water is adsorbed on the surface of these desiccant particles. Passing through the entire desiccant bed, almost all of the water is adsorbed onto the desiccant material, leaving the dry gas to exit the contactor.

(91) "Designated representative" means the person responsible for certifying, signing, and submitting the GHG emissions data report.

(92) ~~(57)~~ "Diesel fuel" means ~~a fuel composed of distillates obtained in petroleum refining operations~~Distillate Fuel No. 1 and Distillate Fuel No. 2, including dyed and nontaxed fuels.

~~(58) "Direct emissions" means greenhouse gas emissions from sources that are under the operational control of the operator.~~

(93) ~~(59)~~ "Distillate fuel oil" means a ~~general~~ classification for a one of the petroleum ~~fraction~~fractions produced in conventional distillation operations. ~~It~~ and from crackers and hydrotreating process units. The generic term distillate fuel oil includes kerosene, diesel fuels (Diesel Fuels No. 1, No. 2, and No. 4), and fuel oils. (Fuel Oils No. 1, No. 2, and No. 4).

(94) "Distillate Fuel No. 1" has a maximum distillation temperature of 550°F at the 90 percent recovery point and a minimum flash point of 100°F and includes fuels commonly known as Diesel Fuel No. 1 and Fuel Oil No. 1, but excludes kerosene. This fuel is further subdivided into categories of sulfur content: High Sulfur (greater than 500 ppm), Low Sulfur (less than or equal to 500 ppm and greater than 15 ppm), and Ultra Low Sulfur (less than or equal to 15 ppm).

~~(60) "Distributed emissions" means CO_2 emissions from fuel combustion at cogeneration facilities distributed between energy stream outputs including thermal energy, electricity generation and potentially other product outputs.~~

~~(61) "District heating and cooling" means the distribution of heat or cooling from one or more sources to multiple buildings.~~

(95) "Distillate Fuel No. 2" has a minimum and maximum distillation temperature of 540°F and 640°F at the 90 percent recovery point, respectively, and includes fuels commonly known as Diesel Fuel No. 2 and Fuel Oil No. 2. This fuel is further subdivided into categories of sulfur content: High Sulfur (greater than 500 ppm), Low Sulfur (less than or equal to 500 ppm and greater than 15 ppm), and Ultra Low Sulfur (less than or equal to 15 ppm).

~~(62) "Electricity generating facility" means generating facility.~~

(96) "Distillate Fuel No. 4" is a distillate fuel oil made by blending distillate fuel oil and residual fuel oil, with a minimum flash point of 131°F.

(97) "EIA" means the Energy Information Administration. The Energy Information Administration (EIA) is a statistical agency of the United States Department of Energy.

(98) "E&P Tank" means E&P Tank Version 2.0 for Windows software, copyright 1996-1999 by the American Petroleum Institute and the Gas Research Institute (published 2000).

(99) "Electricity consumed on-site" means the amount of electricity generated on-site and used for other operations at the facility, excluding parasitic power

required for operation of the electricity generating or cogeneration system. This quantity excludes electricity generated off-site, such as electricity purchased from an electric utility.

(100) "Electricity exporter" means marketers and retail providers that hold title to exported electricity. For electricity delivered between balancing authority areas, the entity that holds title to exported electricity is identified on the NERC E-tag as the purchasing-selling entity (PSE) on the tag's physical path, with the point of receipt located inside the state of California and the point of delivery located outside the state of California.

(101) "Electricity generating unit" or "EGU" means any combination of physically connected generator(s), reactor(s), boiler(s), combustion turbine(s), or other prime mover(s) operated together to produce electric power.

(102) "Electricity importers" are marketers and retail providers that hold title to imported electricity. For electricity delivered between balancing authority areas, the entity that holds title to delivered electricity is identified on the NERC E-tag as the purchasing-selling entity (PSE) on the tag's physical path, with the point of receipt located outside the state of California and the point of delivery located inside the state of California. Federal and state agencies are subject to the regulatory authority of ARB under this article and include Western Area Power Administration (WAPA), Bonneville Power Administration (BPA), and California Department of Water and Power (DWR). When PSEs are not subject to the regulatory authority of ARB, including tribal nations, the electricity importer is the immediate downstream purchaser or recipient that is subject to the regulatory authority of ARB.

(103) ~~(63)~~ "Electricity transaction" means the purchase, sale, import, export or exchange of electric power.

(104) "Electricity wheeled through California" means electricity that is generated outside the state of California and delivered into California with final point of delivery outside California.

(105) ~~(64)~~ "Emission factor" means a unique value for determining an amount of a greenhouse gas emitted for a given quantity of activity (e.g., metric ~~tonnes~~tons of carbon dioxide emitted per barrel of fossil fuel burned~~)~~.)

(106) ~~(65)~~ "Emissions" means the release of greenhouse gases into the atmosphere from sources and processes in a facility, including from the combustion of transportation fuels such as natural gas, petroleum products, and natural gas liquids.

(107) ~~(66)~~ "Emissions data report" or "greenhouse gas emissions data report" or "report" means the report prepared by an operator or supplier each year and submitted by electronic means to ARB that provides the information required by this article.

(108) "End user" means a final purchaser of electricity or natural gas not for the purposes of retransmission or resale. In the context of natural gas consumption, an "end user" is the point to which natural gas is delivered for consumption.

(109) "Enforceable" means the authority for ARB to hold a particular party liable and to take appropriate action if any of the provisions of this article are violated.

(110) "Engineering estimation," for the purposes of sections 95150 to 95158 of this article, means an estimate of emissions based on engineering principles applied to measured and/or approximated physical parameters such as dimensions of containment, actual pressures, actual temperatures, and compositions.

(111) "Enhanced oil recovery" or "EOR" means the use of certain methods such as steam (thermal EOR), water flooding or gas injection into existing wells to increase the recovery of crude oil from a reservoir. In the context of this rule, EOR also applies to injection of critical phase carbon dioxide into a crude oil reservoir to enhance the recovery of oil.

(112) "Enterer" means an entity that imports motor vehicle fuel, diesel fuel, fuel ethanol, biodiesel or another biomass-derived fuel or renewable fuel and who is the importer of record under federal customs law or the owner of fuel upon import if the fuel is not subject to federal customs law.

(113) ~~(67)~~ "Entity" means a person, firm, association, organization, partnership, business trust, corporation, limited liability company, company, or government agency.

(114) ~~(68)~~ "Equipment" means any stationary article, machine, or other contrivance, or combination thereof, which may cause the issuance or control the issuance of air contaminants; equipment shall not mean portable equipment, tactical support equipment, or ~~generating units~~electricity generators designated as backup ~~or emergency~~ generators in a permit issued by an air pollution control district or air quality management district.

(115) ~~(69)~~ "Ethane" ~~means a normally gaseous straight-chained~~is a paraffinic hydrocarbon ~~that boils at a temperature of -127.48 degrees Fahrenheit with a chemical~~with molecular formula ~~of~~ C_2H_6.

(116) ~~(70)~~ "Exchange agreement" means a commitment between electricity market participants to swap energy for energy. Exchange transactions do not involve transfers of payment or receipts of money for the full market value of the energy being exchanged, but may include payment for net differences due to market price differences between the two parts of the transaction or to settle minor imbalances.

(117) "Exclusive marketer" means a marketer that has exclusive rights to market electricity for a generating facility or group of generating facilities.

(118) ~~(71)~~ "Executive Officer" means the Executive Officer of the ~~ARB~~California Air Resources Board, or his or her delegate.

(119) "Exported electricity" means electricity generated inside the state of California and delivered to serve load outside California. This includes electricity delivered from a point of receipt inside California, to the first point of delivery outside California, having a final point of delivery outside California. Exported electricity does not include electricity generated inside the state of California then transmitted outside of California, but with a final point of delivery inside California. Exported electricity does not include electricity generated inside the state of California that is allocated to serve the California retail customers of a multi-jurisdictional retail provider, consistent with a cost allocation methodology approved by the California Public Utilities Commission and the utility regulatory commission of at least one additional state in which the multi-jurisdictional retail provider provides retail electric service.

(120) ~~(72)~~ "Facility" means any physical property, plant, building, structure, ~~stationary~~ source, or stationary equipment ~~or grouping of stationary equipment or stationary sources~~ located on one or more contiguous or adjacent properties~~,~~ in actual physical contact or separated solely by a public roadway or other public right-of-way~~,~~ and under common ~~operational~~ownership or common control, that emits or may emit any greenhouse gas. Operators of military installations may classify such installations as more than a single facility based on distinct and independent functional groupings within contiguous military properties.

~~(73) "Feed" means the prepared and mixed materials, which include but are not limited to materials such as limestone, clay, shale, sand, iron ore, mill scale, cement kiln dust, and fly ash, that are fed to the kiln. Feed does not include the fuels used in the kiln to produce heat to form the clinker product.~~

(121) ~~(74)~~ "Feedstock" means the raw material supplied to a process.

~~(75) "Final point of delivery" means the last point of delivery for a given electricity transaction.~~

(122) "Field," in the context of oil and gas system, means standardized field names and codes of all oil and gas fields identified in the United States as defined by the Energy Information Administration Oil and Gas Field Code Master List.

(123) "Finished motor gasoline" means a complex mixture of volatile hydrocarbons, with or without additives, suitably blended to be used in spark ignition engines. Motor gasoline includes conventional gasoline, reformulated gasoline, and all types of oxygenated gasoline. Gasoline also has seasonal variations in an effort to control ozone levels. This is achieved by lowering

the Reid Vapor Pressure (RVP) of gasoline during the summer driving season. Depending on the region of the country the RVP is lowered to below 9.0 psi or 7.8 psi. The RVP may be further lowered by state regulations.

(124) "Firmed and shaped electricity" means electricity that is paired with a variable renewable resource to improve dispatchability and back up the resource to assure customer load is met.

(125) "Flash point" of a volatile liquid is the lowest temperature at which it can vaporize to form an ignitable mixture in air.

(126) ~~(76)~~ "Flare" means a combustion device, whether at ground level or elevated, that uses an open flame to burn combustible gases with combustion air provided by uncontrolled ambient air around the flame. ~~This term includes both ground-level and elevated flares. When used as a verb, the term "flare" means to combust vent gas in a flare.~~

~~(77) "Flexicoking" means a thermal cracking process which converts heavy hydrocarbons such as crude oil, tar sands bitumen, and distillation residues into light hydrocarbons.~~

~~(78) "Flexigas" means a low Btu gas produced during flexicoking.~~

(127) "Flare combustion" means unburned hydrocarbons including CH_4, CO_2, and N_2O emissions resulting from the incomplete combustion of gas in flares.

(128) "Flare combustion efficiency" means the fraction of natural gas, on a volume or mole basis, that is combusted at the flare burner tip.

(129) "Flow monitor" means a component of the continuous emission monitoring system that measures the volumetric flow of exhaust gas.

(130) ~~(79)~~ "Fluid catalytic cracking unit" or "FCCU" means a process unit in a refinery in which petroleum derivative feedstock is charged and fractured into smaller molecules in the presence of a catalyst, or reacts with a contact material to improve feedstock quality for additional processing, and in which the catalyst or contact material is regenerated by burning off coke and other deposits. The unit includes, but is not limited to, the riser, reactor, regenerator, air blowers, spent catalyst, and all equipment for controlling air pollutant emissions and recovering heat.

~~(80) "Fluid catalytic cracking unit regenerator" means the portion of the fluid catalytic cracking unit in which coke burn-off and catalyst regeneration occurs, and includes the regenerator combustion air blower(s).~~

(131) ~~(81)~~ "Fluid coking" means a thermal cracking process utilizing the fluidized-solids technique to remove carbon (coke) for continuous conversion of heavy, low-grade oils into lighter products.

~~(82) "Fly ash" means particles of ash, such as particulate matter that may also have metals attached to them, which are carried up the stack of a combustion unit with gases during combustion.~~

~~(83) "Fossil fuel" means a fuel, such as coal, oil, and natural gas, produced by the decomposition of ancient (fossilized) plants and animals.~~

(132) "Fluorinated greenhouse gas" means sulfur hexafluoride (SF_6), nitrogen trifluoride (NF_3), and any fluorocarbon except for controlled substances as defined at 40 CFR Part 82, subpart A and substances with vapor pressures of less than 1 mm of Hg absolute at 25°C. With these exceptions, "fluorinated GHG" includes any hydrofluorocarbon, any perfluorocarbon, any fully fluorinated linear, branched or cyclic alkane, ether, tertiary amine or aminoether, any perfluoropolyether, and any hydrofluoropolyether.

(133) "Fossil fuel" means natural gas, petroleum, coal, or any form of solid, liquid, or gaseous fuel derived from such material, including for example, consumer products that are derived from such materials and are combusted.

(134) "Fractionates" means the process of separating natural gas liquids into their constituent liquid products.

(135) "Fractionator" means plants that produce fractionated natural gas liquids (NGLs) extracted from produced natural gas and separate the NGLs individual component products: ethane, propane, butanes and pentane-plus (C5+). Plants that only process natural gas but do not fractionate NGLs further into component products are not considered fractionators. Some fractionators do not process production gas, but instead fractionate bulk NGLs received from natural gas processors. Some fractionators both process natural gas and fractionate bulk NGLs received from other plants.

(136) ~~(84)~~ "Fuel" means solid, liquid or gaseous combustible material. Volatile organic compounds burned in destruction devices are not fuels unless they can sustain combustion without use of a pilot fuel and such destruction does not result in a commercially useful end product.

(137) ~~(85)~~ "Fuel analytical data" means ~~any~~ data collected about ~~the~~fuel usage (including mass, volume, and flow rate~~, heat content, or~~) and fuel characteristics (including heating value, carbon content ~~of a fuel~~, and molecular weight) to support emissions calculation.

~~(86) "Fugitive emissions" means the unintended or incidental emissions of greenhouse gases from the transmission, processing, storage, use, or transportation of fossil fuels or other materials, including but not limited to HFCs from refrigeration leaks, SF_6 from electric power distribution equipment, methane from mined coal, and CO_2 emitted from geyser steam and/or fluid used in geothermal generating facilities.~~

(138) "Fuel characteristic data" means, for the purpose of this article, properties of a fuel used for calculating GHG emissions including carbon content, high heat value, and molecular weight.

(139) "Fuel ethanol" means ethanol that meets ASTM D-4806 (August 2008) specifications for blending with gasolines for use as automotive spark-ignition engine fuel.

(140) "Fuel flowmeter system" means a monitoring system which provides a continuous record of the flow rate of fuel oil or gaseous fuel. A fuel flowmeter system consists of one or more fuel flowmeter components, all necessary auxiliary components (e.g., transmitters, transducers, etc.), and a data acquisition and handling system (DAHS).

(141) "Fuel production facility" means a facility, other than a refinery, in which motor vehicle fuel, diesel fuel or biomass-based fuel is produced.

(142) "Fuel supplier" means a supplier of petroleum products, a supplier of biomass-derived transportation fuels, a supplier of natural gas, or a supplier of liquid petroleum gas as specified in this article.

(143) "Fugitive emissions" means those emissions which are unintentional and could not reasonably pass through a stack, chimney, vent, or other functionally-equivalent opening.

(144) "Fugitive emissions detection" means the process of identifying emissions from equipment, components, and other point sources.

(145) ~~(87)~~ "Fugitive source~~"~~" means a source of fugitive emissions.

(146) ~~(88)~~ "Full verification~~"~~" means all verification services as provided in section 95131.

~~(89) "General stationary combustion facility" means a facility not otherwise subject to sector-specific reporting requirements that emits ≥25,000 metric tonnes of CO_2 in 2008 or any subsequent year from stationary combustion sources.~~

~~(90) "Generating facility" means a facility that generates electricity and includes one or more generating units at the same location.~~

(147) "Gas" means the state of matter distinguished from the solid and liquid states by: relatively low density and viscosity; relatively great expansion and contraction with changes in pressure and temperature; the ability to diffuse readily; and the spontaneous tendency to become distributed uniformly throughout any container.

(148) "Gas conditions" means the actual temperature, volume, and pressure of a gas sample.

(149) "Gas gathering/booster stations" means centralized stations where produced natural gas from individual wells is co-mingled, compressed for transport to processing plants, transmission and distribution systems, and other gathering/booster stations which co-mingle gas from multiple production gathering/booster stations. Such stations may include gas dehydration, gravity separation of liquids (both hydrocarbon and water), pipeline pig launchers and receivers, and gas powered pneumatic devices.

(150) "Gas to oil ratio" or "GOR" means the ratio of the volume of gas at standard temperature and pressure that is produced from a volume of oil when depressurized to standard temperature and pressure.

(151) "Generation providing entity" or "GPE" means a merchant selling energy from owned, affiliated, or contractually bound generation.

(152) ~~(91)~~ "Generating unit" means any combination of physically connected generator(s), reactor(s), boiler(s), combustion turbine(s), or other prime mover(s) operated together to produce electric power.

(153) "Geothermal" means heat or other associated energy derived from the natural heat of the earth.

(154) ~~(92)~~ "Global warming potential"" or ""GWP ~~factor~~"" means the ratio of the time-integrated radiative forcing ~~impact~~from the instantaneous release of one ~~mass-based unit~~kilogram of a ~~given greenhouse gas relative to an equivalent unit of carbon dioxide over a given period of time.~~trace substance relative to that of one kilogram of a reference gas, i.e., CO_2.

(155) ~~(93)~~ "Greenhouse gas~~," "greenhouse gases~~" or "GHG" means carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), sulfur hexafluoride (SF_6), hydrofluorocarbons (HFCs), ~~and~~ perfluorocarbons (PFCs), hydrocarbons and other fluorinated greenhouse gases as defined in this section.

(156) "Greenhouse gas emission reduction" or "GHG emission reduction" or "greenhouse gas reduction" or "GHG reduction" means a calculated decrease in GHG emissions relative to a project baseline over a specified period of time.

(157) "Greenhouse gas removal enhancement" or "GHG removal" means the calculated total mass of a GHG removed, relative to a project baseline, from the atmosphere over a specified period of time.

(158) "Greenhouse gas reservoir" or "GHG reservoir" means a physical unit or component of the biosphere, geosphere or hydrosphere with the capability to store, accumulate, or release of a GHG removed from the atmosphere by a GHG sink or a GHG captured from a GHG emission source.

(159) ~~(94)~~ "Greenhouse gas ~~source~~sink" or "GHG sink" means ~~any~~a physical unit~~, process, or other use or activity that releases a greenhouse gas into~~ or process that removes a GHG from the atmosphere.

(160) ~~(95)~~ "Gross generation" or "gross power generated" means the total electrical output of the generating facility or unit, expressed in megawatt hours (MWh) per year.

(161) "HD-5" means a consumer grade of liquefied petroleum gas that contains a minimum of 90% propane, and a maximum of 5% propylene and 5% butanes and ethane.

(162) "HD-10" means liquefied petroleum gas with no more than 10% propylene.

(163) "Heat input rate" means the product (expressed in mmBtu/hr) of the gross calorific value of the fuel (expressed in mmBtu/mass of fuel) and the fuel feed rate into the combustion device (expressed in mass of fuel/hr) and does not include the heat derived from preheated combustion air, recirculated flue gases, or exhaust from other sources.

(164) ~~(96)~~ "High heat value" or "HHV" means the high or gross heat content of the fuel with the heat of vaporization included. The water vapor is assumed to be in a liquid state.

(165) "High-bleed pneumatic devices" are automated flow control devices powered by pressurized natural gas and used for maintaining a process condition such as liquid level, pressure, delta-pressure and temperature. Part of the gas power stream which is regulated by the process condition flows to a valve actuator controller where it vents (bleeds) to the atmosphere at a rate in excess of six standard cubic feet per hour.

(166) ~~(97)~~ "Hydrocarbons" means chemical compounds containing predominantly carbon and hydrogen.

(167) ~~(98)~~ "Hydrofluorocarbons" or "HFCs" means a class of GHGs ~~primarily used as refrigerants,~~ consisting of hydrogen, fluorine, and carbon.

(168) ~~(99)~~ "Hydrogen" means the lightest of all gases, occurring chiefly in combination with oxygen in water; exists also in acids, bases, alcohols, petroleum, and other hydrocarbons.

(169) ~~(100)~~ "Hydrogen plant~~ or "hydrogen production facility~~" means a facility that produces hydrogen with steam hydrocarbon reforming, partial oxidation of hydrocarbons, or other processes.

~~(101) "Indirect energy" means electricity, thermal, or other energy sources provided by a retail provider or facility not owned or operated by the user of the energy.~~

(170) "Imported electricity" means electricity generated outside the state of California and delivered to serve load inside the state of California. Imported electricity includes electricity delivered from a point of receipt located outside the state of California, to the first point of delivery located inside the state of California, having a final point of delivery in California. Imported electricity includes electricity imported into California over a multi-jurisdictional retail provider's transmission and distribution system, or electricity imported into California over a balancing authority's transmission and distribution system. Imported electricity includes electricity that is a result of cogeneration located outside the state of California. Imported electricity does not include electricity wheeled through California, which is electricity that is delivered into California with final point of delivery outside California.

(171) "Importer of record" means the owner or purchaser of the goods.

(172) "Inventory position" means a contractual agreement with the terminal operator for the use of the storage facilities and terminaling services for the fuel.

(173) "Intrastate pipeline" means any pipeline wholly within the state of California that is not regulated as a public utility gas corporation by the California Public Utility Commission (CPUC), not a publicly-owned natural gas utility and is not regulated as an interstate pipeline by the Federal Energy Regulatory Commission.

(174) "Interstate pipeline" means any entity that owns or operates a natural gas pipeline delivering natural gas to consumers in the state and is subject to rate regulation by the Federal Energy Regulatory Commission.

(175) ~~(102)~~ "ISO" means the International Organization for Standardization.

(176) "Jurisdiction" means U.S. state or Canadian province. For purposes of this article, "U.S. state" means U.S. State, the District of Columbia, the Commonwealth of Puerto Rico, the Virgin Islands, Guam, and American Samoa and includes the Commonwealth of the Northern Mariana Islands. For purposes of this article, "province" means any Canadian province or territory.

(177) ~~(103)~~ "Kerosene" ~~means a light distillate fuel that includes No. 1-K and No. 2-K~~is a light petroleum distillate with a maximum distillation temperature of 400°F at the 10-percent recovery point, a final maximum boiling point of 572°F, a minimum flash point of 100°F, and a maximum freezing point of -22°F. Included are No. 1-K and No. 2-K, distinguished by maximum sulfur content (0.04 and 0.30 percent of total mass, respectively), as well as all other grades of kerosene called range or stove oil ~~that have properties similar to those of No. 1 fuel oil~~. "Kerosene" does not include kerosene-type jet fuel.

~~(104) "Kiln" means a device, including any associated preheater or precalciner devices, that produce clinker by heating limestone and other materials for subsequent production of Portland or other cement.~~

(178) "Kiln" means an oven, furnace, or heated enclosure used for thermally processing a mineral or mineral-based substance.

(179) ~~(105)~~ "Kilowatt hour" or "kWh" means the electrical energy unit of measure equal to one thousand watts of power supplied to, or taken from, an electric circuit steadily for one hour. (A watt is a unit of electrical power equal to one ampere under pressure of one volt, or 1/746 horsepower~~)~~.)

(180) ~~(106)~~ "Lead verifier" means a person that has met all of the requirements in section 95132(b)(2) and who may act as the lead verifier of a verification team providing verification services or as a lead verifier providing an independent review of verification services rendered.

(181) "Lead verifier independent reviewer" or "independent reviewer" means a lead verifier within a verification body who has not participated in conducting verification services for a reporting entity, offset project developer, or authorized project designee for the current reporting year who provides an independent review of verification services rendered to the reporting entity as required in section 95131.

(182) ~~(107)~~ "Less intensive verification~~"~~" means the verification services provided in interim years between full verifications; less intensive verification of a reporting entity's emissions data report only requires data checks ~~on an operator~~and document reviews of a reporting entity's emissions data report based on the analysis and risk assessment in the most current sampling plan developed as part of the most current full verification services. This level of verification may only be used if the verifier can provide findings with a reasonable level of assurance.

~~(108) "Liquefied petroleum gas" or "LPG" means a group of hydrocarbon-based gases derived from crude oil refining or natural gas fractionation. They include propane, propylene, normal butane, butane, butylene, isobutene and isobutylene. For convenience of transportation, these gases are liquefied through pressurization.~~

~~(109) "Long-term power contract" means a power contract with a term of five years or more.~~

(183) "Linkage" means the approval of compliance instruments from an external greenhouse gas emission trading system (GHG ETS) to meet compliance obligations under the Cap-and-Trade Regulation, and the reciprocal approval of compliance instruments issued by California to meet compliance obligation in an external GHG ETS.

(184) "Linked jurisdiction" means a jurisdiction which has entered into a linkage agreement pursuant to subarticle 12 of the Cap-and-Trade Regulation.

(185) "Liquefied natural gas" or "LNG" means natural gas (primarily methane) that has been liquefied by reducing its temperature to -260 degrees Fahrenheit at atmospheric pressure.

(186) "Liquefied petroleum gas" or "LPG" means a flammable mixture of hydrocarbon gases used as a fuel. LPG can be mixtures of primarily propane, primarily butane, or mixtures of propane or butane. LPG includes propane grades HD-5, HD-10, and commercial grade propane. LPG also includes both odorized and non-odorized liquid petroleum gas, and is also referred to as LGP, GLP, LP-Gas and propane.

(187) "LNG boiloff gas" means natural gas in the gaseous phase that vents from LNG storage tanks due to ambient heat leakage through the tank insulation and heat energy dissipated in the LNG by internal pumps.

(188) "Local distribution company" or "LDC," for purposes of this article, means a company that owns or operates distribution pipelines, not interstate pipelines, that physically deliver natural gas to end users and includes public utility gas corporations, publicly-owned natural gas utilities and intrastate pipelines.

(189) "Lookback period" means the specified time period of historical data that the operators must use for missing data substitution as required by the regulation.

(190) "Low-bleed pneumatic devices" means automated flow control devices powered by pressurized natural gas and used for maintaining a process condition such as liquid level, pressure, delta-pressure and temperature. Part of the gas power stream which is regulated by the process condition flows to a valve actuator controller where it vents (bleeds) to the atmosphere at a rate equal to or less than six standard cubic feet per hour.

(191) ~~(110)~~ "Low Btu gas" means gases recovered from casing vents, vapor recovery systems, crude oil and petroleum product storage tanks and other parts of ~~petroleum~~the crude oil refining and ~~the crude oil and~~ natural gas production process.

~~(111) "Low Heating Value" or "LHV" means low or net heat content with the heat of vaporization excluded. The water is assumed to be in the gaseous state.~~

(192) ~~(112)~~ "Marketer" means a purchasing~~/~~-selling entity that takes title to wholesale electricity and is not a retail provider~~, and that is the purchaser/seller at the first point of delivery in California for electric power imported into California, or the last point of receipt in California for power exported from California~~.

(193) "Market-shifting leakage," in the context of an offset project, means increased GHG emissions or decreased GHG removals outside an offset

project's boundary due to the effects of an offset project on an established market for goods or services.

(194) ~~(113)~~ "Material misstatement" means ~~one or more inaccuracies~~an error, omission, or misreporting, or aggregation of the three, identified in the course of verification ~~that result in the total reported emissions, or reported purchases, sales, imports or exports of electricity, being outside the 95 percent accuracy required to receive a positive verification opinion.~~services that leads a verification team to believe that an emissions data report contains errors greater than 5 percent in the reported total CO_2e emissions. Material misstatement is calculated separately for each type of data as specified in section 95131(b)(13).

(195) "Maximum potential fuel flow rate" or "maximum fuel consumption rate" means the maximum fuel use rate the source is capable of combusting. When the source consists of multiple units, the maximum potential fuel use rate is the sum of the maximum potential fuel use rates of all the units aggregated as a source.

(196) "Megawatt hour" or "MWh" means the electrical energy unit of measure equal to one million watts of power supplied to, or taken from, an electric circuit steadily for one hour.

(197) ~~(114)~~ "Methane" or "CH_4" means a GHG consisting on the molecular level of a single carbon atom and four hydrogen atoms.

(198) ~~(115)~~ "Metric ~~tonne~~ton" or "MT" ~~or "tonne"~~ means a common international measurement for ~~the quantity of GHG emissions~~mass, equivalent to ~~about~~ 2204.6 pounds or 1.1 short tons.

(199) "Missing data period" means a period of time during which a piece of data is not collected, is invalid, or is collected while the measurement device is not in compliance with the applicable quality-assurance requirements. In the context of periodic fuel sampling, missing data period is the entire sampling period (e.g. week, month, or quarter) for which corresponding fuel characteristic data are not obtained. In the context of periodic fuel consumption monitoring and recording, a missing data period consists of the consecutive time intervals (e.g. hours, days, weeks, or months) for which fuel consumption during the time period is not monitored and recorded.

(200) ~~(116)~~ "MMBtu" means million British thermal units.

~~(117) "Mobile combustion emissions" means emissions from the transportation of materials, products, waste, and employees resulting from the combustion of fuels in company-owned or controlled mobile combustion sources.~~

~~(118) "Mobile combustion source" means a source of greenhouse gas emissions resulting from combustion by a vehicle or other non-stationary, self-propelled~~

~~combustion source that produces greenhouse gas emissions including, but not limited to, passenger cars, large/heavy duty truck cabs and chassis, light and medium duty trucks and vans, motorcycles, public transit buses, or military tanks or other tracked military vehicles, mobile cranes, bulldozers, concrete mixers, street cleaners, golf carts, all terrain vehicles, trains, airplanes, boats, ships, implements of husbandry, and hauling equipment used inside and around airports, docks, depots, industrial, and commercial plants.~~

(201) ~~(119)~~ "Motor gasoline" means a complex mixture of relatively volatile hydrocarbons with or without small quantities of additives, blended to form a fuel suitable for use in spark-ignition engines. Motor gasoline is characterized as having a boiling range of 122 to 158 ~~degrees Fahrenheit~~°F at the 10-percent recovery point to 365 to 374 ~~degrees Fahrenheit~~°F at the 90-percent recovery point.

(202) "Motor vehicle fuel" means gasoline. It does not include aviation gasoline, jet fuel, diesel fuel, kerosene, liquefied petroleum gas, natural gas in liquid or gaseous form, alcohol, or racing fuel.

(203) ~~(120)~~ "Multi-jurisdictional retail provider" means a retail provider that provides electricity to ~~end users~~consumers in California and in one or more other states~~.~~ in a contiguous service territory or from a common power system.

~~(121) "NAICS" means North American Industry Classification System.~~

(204) "Municipal solid waste" or "MSW" means solid phase household, commercial/retail, and/or institutional waste, such as yard waste and refuse.

(205) ~~(122)~~ "Nameplate generating capacity" means the maximum rated output of a generator under specific conditions designated by the manufacturer~~,~~ ~~expressed in megawatts (MW) or kilowatts (kW)~~. Generator nameplate capacity is usually indicated in units of kilovolt-amperes (kVA) and in Kilowatts (kW) on a nameplate physically attached to the generator.

(206) ~~(123) "Naphtha" means~~Naphthas" (< 401°F) is a generic term applied to a petroleum fraction with an approximate boiling range between 122 ~~degrees Fahrenheit and 400 degrees Fahrenheit~~°F and 400°F. The naphtha fraction of crude oil is the raw material for gasoline and is composed largely of paraffinic hydrocarbons.

(207) ~~(124)~~ "Natural gas" means a naturally occurring mixture of ~~hydrocarbons (e.g., methane, ethane, or propane) produced in geological~~hydrocarbon and non-hydrocarbon gases found in geologic formations beneath the earth's ~~surface that maintains a gaseous state at standard atmospheric temperature and pressure under ordinary conditions~~'s surface, of which its constituents include methane, heavier hydrocarbons and carbon dioxide. Natural gas may be field quality (which varies widely) or pipeline quality. For the purposes of

this article, the definition of natural gas includes similarly constituted fuels such as field production gas, process gas, and fuel gas.

(208) "Natural gas distribution facility" means the distribution pipelines, metering stations, and regulating stations that are operated by a local distribution company (LDC) that is regulated as a separate operating company by a public utility commission or that are operated as an independent municipally-owned distribution system.

(209) "Natural gas driven pneumatic pump" means a pump that uses pressurized natural gas to move a piston or diaphragm, which pumps liquids on the opposite side of the piston or diaphragm.

(210) "Natural Gas Liquids" or "NGLs " means those hydrocarbons in natural gas that are separated from the gas as liquids through the process of absorption, condensation, adsorption, or other methods at lease separators and field facilities. Generally, such liquids consist of ethane, propane, butanes, and pentanes plus. Bulk NGLs refers to mixtures of NGLs that are sold or delivered as undifferentiated product from natural gas processing plants.

(211) "Natural gas liquid fractionator" means an installation that fractionates natural gas liquids (NGLs) into their constituent liquid products (ethane, propane, normal butane, isobutene or pentanes plus) for supply to downstream facilities.

(212) "NERC E-tag" means North American Electric Reliability Corporation (NERC) energy tag representing transactions on the North American bulk electricity market scheduled to flow between or across balancing authority areas.

(213) ~~(125)~~ "Net generation" or "net power generated" means the gross generation minus station service or unit service power requirements, expressed in megawatt hours (MWh) per year. In the case of cogeneration, this value is intended to include internal consumption of electricity for the purposes of a production process, as well as power put on the grid.

~~(126) "NERC E-tag" means North American Electric Reliability Corporation (NERC) energy tag representing transactions on the North American bulk electricity market scheduled to flow between or across control areas.~~

~~(127) "No. 1 diesel fuel" means a light distillate fuel oil that meets the specifications of ASTM (American Society for Testing and Materials) Specification D396-07.~~

~~(128) "No. 1 distillate" means a petroleum distillate that can be used as either a diesel fuel or a fuel oil.~~

~~(129) "No.1 fuel oil" means a light petroleum distillate fuel oil that meets the specifications of ASTM Specification D396-07.~~

~~(130) "No. 2 diesel fuel" means a distillate fuel oil that meets the specifications of ASTM Specification D975-07b.~~

~~(131) "No. 2 distillate" means a petroleum distillate that can be used as either a diesel fuel or a fuel.~~

~~(132) "No. 2 fuel oil" or "heating oil" means a distillate fuel oil that meets the specifications defined in ASTM D396-07.~~

~~(133) "No. 4 fuel oil" means a distillate fuel oil made by blending distillate fuel oil and residual fuel oil stocks that conforms with ASTM Specification D396-07.~~

(214) ~~(134)~~ "Nitrous oxide" or "N_2O" means a GHG consisting at the molecular level of two nitrogen atoms and a single oxygen atom.

(215) ~~(135)~~ "Nonconformance" means the failure to use the methods or emission factors specified in this article to calculate emissions, or the failure to meet any other requirements of the regulation.

(216) "Non-submitted/non-verified emissions data report" means an emissions data report that is not submitted to ARB by the applicable reporting deadline, or for which a verification statement has not been issued by the applicable verification deadline.

(217) ~~(136)~~ "North American Industry Classification System~~" or "NAICS" means a standard for use by Federal statistical agencies in classifying business establishments for the collection, analysis, and publication of statistical data related to the business economy of the United States.~~ (NAICS) code(s)" means the six-digit code(s) that represent the product(s)/activity(s)/service(s) at a facility or supplier as defined in North American Industrial Classification System Manual 2007, available from the U.S. Department of Commerce, National Technical Information Service.

~~(137) "Null power" means any electricity produced by a renewable energy electricity generating facility from which a Western Renewable Energy Generation Information System (WREGIS) or a Nevada Tracks Renewable Energy Credits (NVTREC) certificate has been unbundled and sold separately.~~

~~(138) "NVTREC" means Nevada Tracks Renewable Energy Credits.~~

(218) "Offset credit" means a tradable compliance instrument issued or approved by ARB that represents a GHG reduction or GHG removal enhancement of one metric ton of CO_2e. The GHG reduction or GHG removal enhancement must be real, additional, quantifiable permanent, verifiable and enforceable.

(219) "Offset project" means all equipment, materials, items, or actions that are directly related to or have an impact upon GHG reductions, project emissions or GHG removal enhancements within the offset project boundary.

(220) "Offset project boundary" is defined by and includes all GHG emission sources, GHG sinks or GHG reservoirs that are affected by an offset project and under control of the Offset Project Operator or Authorized Project Designee. GHG emissions sources, GHG sinks or GHG reservoirs not under control of the Offset Project Operator or Authorized Project Designee are not included in the offset project boundary.

(221) "Offset project data report" means the report prepared by an Offset Project Operator or Authorized Project Designee each year that provides the information and documentation required by this article or a compliance offset protocol.

(222) "Offset project operator" means the entity(ies) with legal authority to implement the offset project.

(223) "Offset protocol" means a documented set of procedures and requirements to quantify ongoing GHG reductions or GHG removal enhancements achieved by an offset project and calculate the project baseline. Offset protocols specify relevant data collection and monitoring procedures, emission factors and conservatively account for uncertainty and activity-shifting and market-shifting leakage risks associated with an offset project.

(224) "Offshore" means seaward of the terrestrial borders of the United States, including waters subject to the ebb and flow of the tide, as well as adjacent bays, lakes or other normally standing waters, and extending to the outer boundaries of the jurisdiction and control of the United States under the Outer Continental Shelf Lands Act (43 U.S.C. §1331 et seq).

(225) "Offshore petroleum and natural gas production facility" means each platform structure and all associated equipment as defined in section 95150(a)(1) of this article.

(226) "Onshore petroleum and natural gas production facility" means all petroleum or natural gas equipment associated with all petroleum or natural gas production wells under common ownership or common control by an onshore petroleum and natural gas production owner or operator located in a single hydrocarbon basin as defined by the American Association of Petroleum Geologists which is assigned a three digit Geologic Province Code. Where an operating entity holds more than one permit in a basin, then all onshore petroleum and natural gas production equipment relating to all permits in their name in the basin is one onshore petroleum and natural gas production facility.

(227) "Onshore petroleum and natural gas production owner or operator" means the entity who is the permitee to operate petroleum and natural gas wells on the state drilling permit or a state operating permit where no drilling permit is issued by the state, which operates an onshore petroleum and/or natural gas production facility. Where more than one entity are permitees on the state drilling permit, or operating permit where no drilling permit is issued by the state, the permitted entities for the joint facility must designate one entity to report all emissions from the joint facility.

(228) "Operating pressure" means the containment pressure that characterizes the normal state of gas or liquid inside a particular process, pipeline, vessel or tank.

(229) ~~(139)~~ "Operational control" for a facility subject to this article means the authority to introduce and implement operating, environmental, health and safety policies. In any circumstance where this authority is shared among multiple entities, the entity holding the permit to operate from the local air pollution control district or air quality management district is considered to have operational control for purposes of this article.

(230) ~~(140)~~ "Operator~~"~~" means the entity, including an owner, having operational control of a facility~~, or other entity, from which an emissions data report is required under this article. For purposes of reporting electricity transactions as required in section 95111 "operator" means a retail provider, marketer, or facility operator.~~. For onshore petroleum and natural gas production, the operator is the operating entity listed on the state well drilling permit, or a state operating permit for wells where no drilling permit is issued by the state.

~~(141) "Pacific Northwest" or "PNW" means Washington, Oregon, Idaho, Montana, and British Columbia.~~

(231) "Other Biomass-Derived Fuel" means a biomass-derived fuel for which a reporting entity is required to hold a compliance obligation under title 17, California Code of Regulations, section 95852(g).

(232) "Outer Continental Shelf" means all submerged lands lying seaward and outside of the area of lands beneath navigable waters as defined in 43 U.S.C. § 1301, and of which the subsoil and seabed appertain to the United States and are subject to its jurisdiction and control.

(233) ~~(142)~~ "Perfluorocarbons" or "PFCs" means a class of greenhouse gases consisting on the molecular level of carbon and fluorine.

(234) "Permanent" means, in the context of offset credits, either that GHG reductions or GHG removal enhancements are not reversible, or when GHG reductions or GHG removal enhancements may be reversible, that mechanisms are in place to replace any reversed GHG emission reductions or GHG removal enhancements to ensure that all credited reductions endure

for a period that is comparable to the atmospheric lifetime of an anthropogenic CO_2 emission.

(235) ~~(143)~~ "Petroleum" means oil removed from the earth and the oil derived from tar sands~~,~~ and shale ~~and coal~~.

(236) ~~(144)~~ "Petroleum coke" means a ~~residue high in carbon~~black solid residue, obtained mainly by cracking and carbonizing of petroleum derived feedstocks, vacuum bottoms, tar and pitches in processes such as delayed coking or fluid coking. It consists mainly of carbon (90 to 95 percent), has low ash content, and ~~low in hydrogen that is the final product of thermal decomposition in the condensation process in cracking~~may be used as a feedstock in coke ovens. This product is also known as marketable coke or catalyst coke.

(237) ~~(145)~~ "Petroleum refinery" or "refinery" means any facility engaged in producing gasoline, ~~aromatics~~gasoline blending stocks, naphtha, kerosene, distillate fuel oils, residual fuel oils, lubricants, or asphalt~~, or other products~~ (bitumen) through distillation of petroleum or through redistillation, cracking, ~~rearrangement~~ or reforming of unfinished petroleum derivatives. Facilities that distill only pipeline transmix (off-spec material created when different specification products mix during pipeline transportation) are not petroleum refineries, regardless of the products produced.

(238) "Physical address," with respect to a United States parent company as defined in this section, means the street address, city, State and zip code of that company's physical location.

(239) "Pipeline quality natural gas" means natural gas having a high heat value greater than 970 Btu/scf and equal to or less than 1,100 Btu/scf, and which is at least ninety percent methane by volume, and which is less than five percent carbon dioxide by volume.

(240) "Point of delivery" means the point on an electricity transmission or distribution system where a deliverer makes electricity available to a receiver, or available to serve load. This point can be an interconnection with another system or a substation where the transmission provider's transmission and distribution systems are connected to another system, or a distribution substation where electricity is imported into California over a multi-jurisdictional retail provider's distribution system.

(241) ~~(146) "Point of delivery" means a~~"Point of receipt" the point on an ~~electric system where a power supplier delivers electricity to the receiver of that energy.~~ electricity transmission or distribution system where an electricity receiver receives electricity from a deliverer. This point can be an interconnection with another system or a substation where the transmission provider's transmission and distribution systems are connected to another system.

~~(147) "Point of receipt" means a point on an electric system where an entity receives electricity from a supplier. This point can be an interconnection with another system or a generator busbar.~~

(242) ~~(148)~~ "Point source" means any separately identifiable stationary point from which greenhouse gases are emitted.

~~(149) "Portable" is as defined in title 17, California Code of Regulations, section 93116.2(a)(28).~~

(243) "Portable" means designed and capable of being carried or moved from one location to another. Indications of portability include wheels, skids, carrying handles, dolly, trailer, or platform. Equipment is not portable if any one of the following conditions exists:

(A) The equipment is attached to a foundation.

(B) The equipment or a replacement resides at the same location for more than 12 consecutive months.

(C) The equipment is located at a seasonal facility and operates during the full annual operating period of the seasonal facility, remains at the facility for at least two years, and operates at that facility for at least three months each year.

(D) The equipment is moved from one location to another in an attempt to circumvent the portable residence time requirements of this definition.

(244) ~~(150)~~ "Portland cement" means hydraulic cement (cement that not only hardens by reacting with water but also forms a water-resistant product) produced by pulverizing clinkers consisting essentially of hydraulic calcium silicates, usually containing one or more of the forms of calcium sulfate as an inter-ground addition.

(245) "Position Holder" means an entity that holds an inventory position in motor vehicle fuel, ethanol, distillate fuel, biodiesel, or renewable diesel as reflected in the records of the terminal operator or a terminal operator that owns motor vehicle fuel or diesel fuel in its terminal.

(246) ~~(151)~~ "Positive verification ~~opinion~~statement" means a verification ~~opinion~~statement rendered by a verification body ~~stating~~attesting that the verification body can say with reasonable assurance that the submitted emissions data report is free of material misstatement and ~~includes a qualifying statement~~ that the emissions data report conforms to the requirements of this article.

(247) ~~(152)~~ "Power" means electricity, except where the context makes clear that another meaning is intended.

(248) ~~(153)~~ "Power contract" means ~~an arrangement~~a written document arranging for the ~~purchase~~procurement of electricity. Power contracts may be, but are not limited to, power purchase agreements and tariff provisions.

~~(154) "Pressure swing adsorption" or "PSA" means a gas purification process which selectively concentrates target gas molecules using porous, high surface area solid adsorbents and elevated pressure.~~

~~(155) "PSA off-gas" or "tail-gas" means the impurity stream resulting from the sequential PSA pressurization/depressurization purification process.~~

(249) "Primary fuel" means the main fuel type (expressed in mmBtu) consumed by a unit for the applicable calendar year.

(250) ~~(156)~~ "Prime mover" means the type of equipment such as an engine or water wheel that drives an electric generator. "Prime movers" include, but are not limited to, reciprocating engines, combustion or gas turbines, steam turbines, microturbines, and fuel cells.

(251) ~~(157)~~ "Process" means the intentional or unintentional reactions between substances or their transformation, including, but not limited to, the chemical or electrolytic reduction ~~of~~or metal ores, the thermal decomposition of substances, and the formation of substances for use as product or feedstock.

~~(158) "Process emissions" means greenhouse gas emissions other than combustion emissions occurring as a result of a process.~~

(252) "Process emissions" means the emissions from industrial processes (e.g., cement production, ammonia production) involving chemical or physical transformations other than fuel combustion. For example, the calcination of carbonates in a kiln during cement production or the oxidation of methane in an ammonia process results in the release of process CO_2 emissions to the atmosphere. Emissions from fuel combustion to provide process heat are not part of process emissions, whether the combustion is internal or external to the process equipment.

(253) ~~(159)~~ "Process gas" means any gas generated by an industrial process such as petroleum refining.

(254) ~~(160)~~ "Process vent" means an opening where a gas stream is continuously or periodically discharged during normal operation.

(255) "Producer" means a person who owns, leases, operates, controls or supervises a California production facility.

(256) ~~(161)~~ "Professional judgment" means the ability to render sound decisions based on professional qualifications and relevant greenhouse gas accounting and auditing experience.

(257) "Project baseline" means, in the context of a specific offset project, a conservative estimate of business-as-usual GHG emission reductions or

GHG removal enhancements for the offset project's GHG emission sources, GHG sinks, or GHG reservoirs within the offset project boundary.

(258) ~~(162)~~ "Propane" ~~means a normally straight chain hydrocarbon that boils at -43.67 degrees Fahrenheit and is represented by the chemical~~is a paraffinic hydrocarbon with molecular formula C_3H_8.

(259) "Public utility gas corporation" is a gas corporation defined in California Public Utilities Code section 222 that is also a public utility as defined in California Public Utilities Code section 216.

(260) "Publicly-owned natural gas utility" means a municipality or municipal corporation, a municipal utility district, a public utility district, or a joint powers authority that includes one or more of these agencies that furnishes natural gas services to end users.

(261) "Pump" means a device used to raise pressure, drive, or increase flow of liquid streams in closed or open conduits.

(262) "Pump seal emissions" means hydrocarbon gas released from the seal face between the pump internal chamber and the atmosphere.

(263) "Pump seals" means any seal on a pump drive shaft used to keep methane and/or carbon dioxide containing light liquids from escaping the inside of a pump case to the atmosphere.

(264) ~~(163)~~ "Purchasing~~/~~-selling entity" or "PSE" means ~~an~~the functional entity that ~~is eligible to purchase or sell energy or~~purchases or sells, and takes title to energy, capacity, and ~~reserve transmission~~reliability related services. A PSE is identified on a NERC E-tag for each physical path segment.

(265) ~~(164)~~ "Pure" means consisting of at least 97 percent by mass of a specified substance. For facilities burning biomass fuels, this means the fraction of biomass carbon accounts for at least 97 percent of the total amount of carbon in the fuel burned at the facility.

~~(165) "Purge gas" means nitrogen, carbon dioxide, liquefied petroleum gas, or natural gas used to maintain a non-explosive mixture of gases in a flare header or provide sufficient exit velocity to prevent regressive flame travel back into the flare header.~~

~~(166) "Qualifying facility" means a cogeneration or small power production facility that meets ownership, operating, and efficiency criteria established by the Federal Energy Regulatory Commission (FERC) pursuant to the Public Utility Regulatory Policies Act.~~

(266) "Qualified positive verification statement" means a statement rendered by a verification body attesting that the verification body can say with reasonable assurance that the submitted emissions data report is free of material

misstatement, but the emissions data report may include one or more nonconformance(s) with the requirements of this article which do not result in a material misstatement.

(267) "QA/QC" means quality assurance and quality control.

(268) "Quality-assured data" or "quality-assured value" means the data are obtained from a monitoring system that is operating within the performance specifications and the quality assurance/quality control procedures set forth in the applicable rules, such as 40 CFR Part 60 or Part 75, without unscheduled maintenance, repair, or adjustment.

(269) "Quantifiable" means, in the context of offset projects, the ability to accurately measure and calculate GHG reductions or GHG removal enhancements relative to a project baseline in a reliable and replicable manner for all GHG emission sources, GHG sinks or GHG reservoirs included within the offset project boundary, while accounting for uncertainty, activity-shifting leakage and market-shifting leakage.

(270) "Rack" means a mechanism for delivering motor vehicle fuel or diesel from a refinery or terminal into a truck, trailer, railroad car, or other means of non-bulk transfer.

(271) "Real" means, in the context of offset projects, that GHG reductions or GHG enhancements result from a demonstrable action or set of actions, and are quantified using appropriate, accurate and conservative methodologies that account for all GHG emissions sources, GHG sinks, and GHG reservoirs within the offset project boundary and account for uncertainty and the potential for activity-shifting leakage and market-shifting leakage.

(272) ~~(167)~~ "Reasonable assurance" means a high degree of confidence that submitted data and statements are valid.

(273) "Reciprocating compressor" means a piece of equipment that increases the pressure of a process natural gas by positive displacement, employing linear movement of a shaft driving a piston in a cylinder.

(274) ~~(168)~~ "Recycled" ~~means~~refers to a material that is reused or reclaimed.

(275) "Reciprocating compressor rod packing" means a series of flexible rings in machined metal cups that fit around the reciprocating compressor piston rod to create a seal limiting the amount of compressed natural gas that escapes to the atmosphere.

(276) "Re-condenser" means heat exchangers that cool compressed boil-off gas to a temperature that will condense natural gas to a liquid.

(277) ~~(169)~~ "Refinery fuel gas" or "still gas" means gas generated at a petroleum refinery or any gas generated by a refinery process unit, and that is combusted separately or in any combination with any type of gas or used as a chemical feedstock.

(278) "Reformulated Gasoline Blendstock for Oxygenate Blending" or "RBOB" has the same meaning as defined in title 13 of the California Code of Regulations, section 2260(a).

(279) "Relative Accuracy Test Audit" means a method of determining the correlation of continuous emissions monitoring system data to simultaneously collected reference method test data, such as required in 40 CFR Part 60 and 40 CFR Part 75.

(280) "Renewable diesel" means a motor vehicle fuel or fuel additive that is all of the following:

(A) Registered as a motor vehicle fuel or fuel additive under 40 CFR Part 79;

(B) Not a mono-alkyl ester;

(C) Intended for use in engines that are designed to run on conventional diesel fuel; and

(D) Derived from nonpetroleum renewable resources.

(281) ~~(170)~~ "Renewable energy" means energy from sources that constantly renew themselves or that are regarded as practically inexhaustible. Renewable energy includes~~, but is not limited to,~~ energy derived from solar, wind, geothermal, hydroelectric, wood, biomass, tidal power, sea currents, and ocean thermal gradients.

(282) "Reporting entity" means a facility operator, supplier, or electric power entity subject to the requirements of this article.

(283) ~~(171) "Report year~~Reporting period" means the calendar year ~~for~~ which ~~emissions are being reported in the emissions~~coincides with the data year for the GHG report.

(284) "Reporting year" or "report year" means data year.

(285) "Reservoir" means a porous and permeable underground natural formation containing significant quantities of hydrocarbon liquids and/or gases. A reservoir is characterized by a single natural pressure system.

(286) ~~(172)~~ "Residual fuel oil" means a general classification for the heavier oils, known as No. 5 and No. 6 fuel oils, that remain after the distillate fuel oils and lighter hydrocarbons are distilled away in refinery operations.

(287) ~~(173)~~ "Retail provider" means an entity that provides electricity to retail end users in California and is an electric corporation as defined in Public Utilities

Code section 218, electric service provider as defined in Public Utilities Code section 218.3, local publicly owned electric utility as defined in Public Utilities Code section ~~9604,~~224.3, a community choice aggregator as defined in Public Utilities Code section 331.1, or the Western Area Power Administration. For purposes of this article, electrical cooperatives, as defined by Public Utilities Code section 2776, are excluded.

~~(174) "Screening value" or "SV" means the instrument reading (ppmv) obtained when components, including but not limited to valves, pump seals, connectors, flanges, open-ended lines and other equipment components, are evaluated for leakage as described in United States Environmental Protection Agency (U.S. EPA) Method 21 – Determination of Volatile Organic Compound Leaks (1981).~~

(288) "Retail sales" means electricity sold to retail end users.

(289) "Retail end-use customer" or "retail end user" means a residential, commercial, agricultural, or industrial electric customer who buys electricity to be consumed as a final product and not for resale.

(290) "Sales oil" means produced crude oil or condensate measured at the production lease automatic custody transfer (LACT) meter or custody transfer meter tank gauge.

(291) ~~(175)~~ "Sector" means a broad industrial categorization such as specified in section ~~95101(b).~~95101.

~~(176) "Self-generation facility" means a facility dedicated to serving a particular end user, usually located on the user's premises. The facility may either be owned directly by the end user or owned by an entity with a contractual arrangement to provide electricity to meet some or all of the user's load.~~

~~(177) "Small refiner" is as defined in Title 13, California Code of Regulations, section 2260(a)(32).~~

(292) "Sector-based offset credit" means a credit issued from a sector-based crediting program once the crediting baseline for a sector has been reached. For the limited purposes of this definition, "sector" means a group or subgroup of an economic activity - or a group of economic activities - as in "service sector" - or a cross-section of a group of economic activities - as in "informal sector."

(293) "Sector-based crediting program" is a GHG emissions reduction crediting mechanism established by a country, region, or subnational jurisdiction in a developing country and covering a particular economic sector within that jurisdiction. A program's performance is based on achievement toward an emissions reduction target for the particular sector within the boundary of the jurisdiction and beyond. Responsibility for reducing emissions in a sector-based crediting program is shared between GHG mitigation policies and

activities specific to that sector that exceed legal requirements and market mechanisms. For the limited purposes of this definition, "sector" means a group or subgroup of an economic activity - or a group of economic activities - as in "service sector" - or a cross-section of a group of economic activities - as in "informal sector."

(294) "Separator" means a vessel in which streams of multiple phases are gravity separated into individual streams of single phase.

(295) "Short ton" means a common international measurement for mass, equivalent to 2,000 pounds.

(296) "Shutdown" means the cessation of operation of an emission source for any purpose.

(297) "Sour natural gas" means natural gas that contains significant concentrations of hydrogen sulfide and/or carbon dioxide that exceed the concentrations specified for commercially saleable natural gas delivered from transmission and distribution pipelines.

(298) ~~(178)~~ "Source" means greenhouse gas source~~, as defined in this section~~; any physical unit, process, or other use or activity that releases a greenhouse gas into the atmosphere.

~~(179) "Southwest" or "SW" means Arizona, Nevada, Utah, Colorado, and western New Mexico.~~

(299) ~~(180)~~ "Specified source of ~~power~~electricity" or "specified source" means a ~~particular generating unit or~~ facility ~~for which electrical generation can be confidently tracked due to~~or unit which is permitted to be claimed as the source of imported electricity delivered by an electricity importer. The electricity importer must have either full or partial ownership ~~or due to its identification in a power contract including any California eligible renewable resource~~in the facility/unit or a written contract to procure electricity generated by that facility/unit. Specified facilities/units include cogeneration systems. Specified source also means electricity procured from an asset-controlling supplier recognized by the ARB.

(300) "Standard cubic foot" or "scf" is a measure of quantity of gas, equal to a cubic foot of volume at 60 degrees Fahrenheit and either 14.696 pounds per square inch (1 atm) or 14.73 PSI (30 inches Hg) of pressure.

(301) ~~(181)~~ "Standard conditions" or "~~STP" or "~~standard temperature and pressure (STP)" means ~~a temperature of 20 degrees Celsius (~~68 degrees Fahrenheit~~)~~ and ~~an absolute pressure of 760 mm (30 inches) of mercury or 60 degrees Fahrenheit and 1 atmosphere~~14.7 pounds per square inch absolute.

~~(182) "Standard cubic foot" or "scf" means the amount of gas that would occupy a volume of one cubic foot if free of combined water at standard conditions.~~

(302) "SSM" means periods of startup, shutdown and malfunction during flare operations.

(303) ~~(183)~~ "Stationary" means neither portable nor self propelled, and operated at a single facility.

~~(184) "Stationary combustion source" means a stationary source of combustion emissions, and for the purposes of this article does not include portable equipment, backup generators, or emergency generators as specified in section 95101(c)(2) and section 95101(c)(3).~~

(304) ~~(185)~~ "Storage tank" means any tank, other container, or reservoir used for the storage of organic liquids, excluding tanks that are permanently affixed to mobile vehicles such as railroad tank cars, tanker trucks or ocean vessels.

(305) "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.

(306) ~~(186)~~ "Sulfur hexafluoride" or ~~"~~"SF_6" means a GHG consisting on the molecular level of a single sulfur atom and six fluorine atoms.

~~(187) "Sulfur recovery unit" or "SRU" means a process unit that recovers elemental sulfur from gases that contain reduced sulfur compounds and other pollutants, usually by a vapor-phase catalytic reaction of sulfur dioxide and hydrogen sulfide.~~

(307) ~~(188)~~ "Supplemental firing" means an energy input to the cogeneration facility used only in the thermal process of a topping -cycle plant, or in the ~~electricity~~electric generating or manufacturing process of a bottoming -cycle ~~plant~~cogeneration facility.

(308) "Supplier" means a producer, importer, or exporter of a fossil fuel or an industrial greenhouse gas.

(309) "Sweet Gas" means natural gas with low concentrations of hydrogen sulfide (H_2S) and/or carbon dioxide (CO_2) that does not require (or has already had) acid gas treatment to meet pipeline corrosion-prevention specifications for transmission and distribution.

(310) ~~(189)~~ "Tactical support equipment" is as defined in ~~title~~Title 17, California Code of Regulations, section 93116.2(a)(36).

~~(190) "Thermal host" means the user of the steam or heat output of a cogeneration facility.~~

~~(191) "Ton" means a short ton equal to 2000 pounds.~~

(311) "Terminal" means a motor vehicle fuel or diesel fuel storage and distribution facility that is supplied by pipeline or vessel, and from which motor vehicle fuel may be removed at a rack. "Terminal" includes a fuel production facility

where motor vehicle fuel is produced and stored and from which motor vehicle fuel may be removed at a rack.

(312) "Terminal Operator" means any entity that owns, operates or otherwise controls a terminal that is supplied by pipeline or vessel and from which accountable fuel products may be removed at a rack.

(313) "Thermal energy" means the thermal output produced by a combustion source used directly as part of a manufacturing process but not used to produce electricity.

(314) "Tier" means the level of calculation method from 40 CFR §98.33 that is required for a stationary combustion source in section 95115 of this article.

(315) "Tier 1" means a stationary combustion calculation method that applies default values for emission factors and high heat value to generate an emissions estimate, as specified in 40 CFR §98.33.

(316) "Tier 2" means a stationary combustion calculation method that applies a default value for an emission factor and a fuel's measured high heat value (or a boiler efficiency for steam-generating solid fuels) to generate an emissions estimate, as specified in 40 CFR §98.33.

(317) "Tier 3" means a stationary combustion calculation method that utilizes a fuel's measured carbon content to generate an emissions estimate, as specified in 40 CFR §98.33.

(318) "Tier 4" means a stationary combustion calculation method that utilizes quality-assured data from a continuous emission monitoring system to generate an emissions estimate, as specified in 40 CFR §98.33. This method may also capture process emissions from a common stack.

(319) ~~(192)~~ "Topping cycle ~~plant~~" means a type of cogeneration ~~facility~~system in which the energy input to the ~~facility~~plant is first used to produce ~~useful power output~~electricity, and at least some of the reject heat from the ~~power~~electricity production process is then used to provide useful thermal output.

~~(193) "Total organic carbon" or "TOC" means a measure of the total organic carbon molecules present in a sample.~~

~~(194) "Transferred CO_2" means carbon dioxide that is not emitted directly at the facility but is sold and/or transferred out of the installation as a pure substance.~~

(320) "Transmission pipeline" means a high pressure cross country pipeline transporting sellable quality natural gas from production or natural gas processing to natural gas distribution pressure let-down, metering, regulating stations where the natural gas is typically odorized before delivery to customers.

(321) "Tribal nation" means those Native American tribes in the United States and listed in the Federal Register.

(322) "Turbine meter" means a flow meter in which a gas or liquid flow rate through the calibrated tube spins a turbine from which the spin rate is detected and calibrated to measure the fluid flow rate.

(323) ~~(195)~~ "Uncertainty" means the degree to which data or a data system is deemed to be indefinite or unreliable.

(324) "Uncontrolled blowdown system" means the use of a blowdown procedure that does not result in the recovery of emissions for flaring or re-injection.

(325) "Unconventional wells" means gas wells in producing fields that employ hydraulic fracturing to enhance gas production volumes.

(326) "United States" means the 50 States, the District of Columbia, the Commonwealth of Puerto Rico, American Samoa, the Virgin Islands, Guam, and any other Commonwealth, territory or possession of the United States, as well as the territorial sea as defined by Presidential Proclamation No. 5928.

(327) "United States parent company(s)" mean the highest-level United States company(s) with an ownership interest in the reporting entity as of December 31 of the reporting year.

(328) ~~(196)~~ "Unspecified source of ~~power~~electricity" or "unspecified source" means electricity generation that cannot be matched to a ~~particular generating facility. Unspecified sources of power may include power purchased from entities that own fleets of generating facilities such as independent power producers, retail providers, and federal power agencies and power purchased from electricity marketers, brokers, and markets~~specific facility or unit that generates electricity or matched to an asset-controlling supplier recognized by the ARB. Unspecified sources contribute to the bulk system power pool and typically are dispatchable, marginal resources that do not serve baseload.

~~(197) "Useful power output" means the electric or mechanical energy made available for use, exclusive of any such energy used in the power production process.~~

(329) "U.S. EPA" means the United States Environmental Protection Agency.

(330) ~~(198)~~ "Useful thermal output" means the thermal energy made available in a cogeneration system for use in any industrial or commercial process, heating or cooling application, or delivered to other end users, i.e., total thermal energy made available for processes and applications other than electrical generation.

(331) "Vapor recovery system" means any equipment located at the source of potential gas emissions to the atmosphere or to a flare, that is composed of piping, connections, and, if necessary, flow-inducing devices, and that is used for routing the gas back into the process as a product and/or fuel.

(332) "Vaporization unit" means a process unit that performs controlled heat input to vaporize LNG to supply transmission and distribution pipelines or consumers with natural gas.

(333) "Variable renewable resource" means run-of-river hydroelectric, solar, or wind energy that requires firming and shaping to meet load requirements.

(334) "Vented emissions" means intentional or designed releases of CH_4 or CO_2 containing natural gas or hydrocarbon gas (not including stationary combustion flue gas), including process designed flow to the atmosphere through seals or vent pipes, equipment blowdown for maintenance, and direct venting of gas used to power equipment (such as pneumatic devices).

(335) "Verifiable," in the context of offset projects, means that an offset project data report assertion is well documented and transparent such that it lends itself to an objective review by an accredited verification body.

(336) ~~(199)~~ "Verification" means ~~the process used to ensure that an operator~~a systematic, independent and documented process for evaluation of a reporting entity's emissions data report ~~is free of material misstatement and complies with ARB's~~against ARB's reporting procedures and methods for ~~calculating~~calculation and reporting GHG emissions.

(337) ~~(200)~~ "Verification body" means a firm ~~or AQMD/APCD,~~ accredited by ARB, that is able to render a verification ~~opinion~~statement and provide verification services for ~~operators~~reporting entities subject to reporting under this article.

~~(201) "Verification cycle" means one year of full verification and the next consecutive two years of less intensive verification for operators subject to annual verification. For operators subject to triennial verification, a verification cycle means one year of full verification, and if elected, the next consecutive two years of less intensive verification. A verification cycle cannot exceed three calendar years.~~

~~(202) "Verification opinion" means the final opinion rendered by a verification body attesting whether an operator's emissions data report is free of material misstatement and a qualifying statement whether the emissions data report conforms to the requirements of this article.~~

(338) ~~(203)~~ "Verification services" means services provided during verification as specified in section ~~95131,~~95131 beginning with the development of the verification plan or first site visit, including but not limited to reviewing ~~an operator~~a reporting entity's emissions data report, verifying its accuracy

according to the standards specified in this article, assessing the ~~operator~~reporting entity's compliance with this article, and submitting a verification ~~opinion~~statement to the ARB.

(339) "Verification statement" means the final statement rendered by a verification body attesting whether a reporting entity's emissions data report is free of material misstatement, and whether the emissions data report conforms to the requirements of this article.

(340) ~~(204)~~ "Verification team" means all of those working for a verification body, including all subcontractors, to provide verification services for ~~an operator. The lead verifier for the verification team shall be a lead verifier in the verification body~~a reporting entity.

(341) "Verified emissions data report" means an emissions data report that has been reviewed by a third-party verifier and has a verification statement accepted by the ARB.

(342) ~~(205)~~ "Verifier" means an individual accredited by ARB to carry out verification services as specified in section 95131.

(343) "Verifier review" means a verifier conducts all reviews and services in section 95131, except the material misstatement assessment under section 95131(b)(14). If some of the sources are selected for data checks based on the sampling plan, the verifier will check for conformance with the requirements of this article.

(344) ~~(206)~~ "Volatile organic ~~compounds~~compound" or "VOC" means any volatile compound of carbon, excluding carbon monoxide, carbon dioxide, carbonic acid, metallic carbides or carbonates, and ammonium carbonate, which participates in atmospheric photochemical reactions.

~~(207) "Waste-derived fuel" means a fuel typically derived from waste(s) and generally used as a substitute for conventional fossil fuels. Waste-derived fuels can include fossil fuels such as waste oil, plastics, or solvents; biomass such as dried sewage or impregnated saw dust; or fractions of both fossil fuels and biomass such as municipal solid waste or tires.~~

~~(208) "Wastewater" means any process water which contains oil, emulsified oil, or other organic compounds that are not recycled or otherwise used in a facility.~~

~~(209) "Wastewater separator" means equipment used to separate oils and water from locations downstream of process drains.~~

(345) "Weighted monthly average" means the sum of the products of two values measured during the same time period divided by the sum of the values not being averaged. For weighted average HHV it would be the sum of the

products of volume and HHV measured during the same time period divided by the sum of the volumes.

(346) "Well completions" means a process that allows for the flow of petroleum or natural gas from newly drilled wells to expel drilling and reservoir fluids and test the reservoir flow characteristics. This process includes high-rate back-flow of injected water and sand used to fracture and prop-open fractures in low permeability gas reservoirs.

(347) "Well workover" means the performance of one or more of a variety of remedial operations on producing oil and gas wells to try to increase production. This process also includes high-rate back-flow of injected water and sand used to re-fracture and prop-open new fractures in existing low permeability gas reservoirs.

(348) "Wellhead" means the piping, casing, tubing and connected valves protruding above the Earth's surface for an oil and/or natural gas well. The wellhead ends where the flow line connects to a wellhead valve.

(349) "Wet natural gas" means natural gas in which water vapor exceeds the concentration specified for commercially saleable natural gas delivered from transmission and distribution pipelines. This input stream to a natural gas dehydrator is referred to as "wet gas".

(350) "Wholesale sales" means sales to other LDCs.

~~(210) "WREGIS" means Western Renewable Energy Generation Information System.~~

NOTE: Authority cited: Sections 39600, 39601, 39607, 39607.4, 41511, 38510, and 38530, Health and Safety Code. Reference: Sections 39600, 41511, and 38530, Health and Safety Code.

§ 95103. ~~General~~ Greenhouse Gas Reporting Requirements.

The facilities, suppliers, and entities specified in section 95101 must monitor emissions and submit emissions data reports to the Air Resources Board following the requirements specified in 40 CFR §98.3 and §98.4, except as otherwise provided in this section.

(a) ~~***General Reporting Requirements.*** The operators listed in section 95101(b), except as provided in section 95103(e), shall submit greenhouse gas emissions data reports on the schedule specified in section 95103(b).~~

Abbreviated Reporting for Facilities with Emissions Below 25,000 Metric Tons of CO_2e. The facility operator without a compliance obligation under the Cap-and-Trade Regulation during any year of the current three-year compliance period, who is also not subject to the reporting requirements of 40 CFR Part 98 and whose total stationary and process emissions are below 25,000 metric tons of CO_2e in 2011 and each subsequent year, may submit abbreviated emissions data reports under this article. This provision does not apply to suppliers or electric power entities. Abbreviated reports must include the following information:

(1) ~~The operator shall submit a report for the 2008 report year that applies best available data and methods to develop emissions estimates. The operator shall submit reports for 2009 and subsequent report years that meet all specifications of this article.~~Facility name, assigned ARB identification number, physical street address including the city, state and zip code, air basin, air district, county, and geographic location.

(2) ~~***Stationary Sources.*** The operator shall identify, calculate, and report CO_2, N_2O, CH_4, SF_6, HFC, and PFC emissions from stationary combustion, process, and fugitive sources at the facility as specified in sections 95110 through 95115. The operator shall calculate and report each GHG separately for each fuel type used. The operator shall monitor and report fuel consumption for the facility, and for each process unit or group of units where fuel use is separately metered.~~Total facility GHG emissions aggregated for all stationary fuel combustion units and calculated according to any method available by fuel type in 40 CFR §98.33(a), expressed in metric tons of total CO_2, CO_2 from biomass-derived fuels, CH_4, and N_2O.

(3) ~~The operator shall separately identify, calculate and report all direct emissions of CO_2 resulting from combustion of biomass-derived fuels as specified in sections 95110 through 95115.~~If applicable, GHG emissions for each process source type found in 40 CFR Part 98 that was in operation at the facility during the period covered by the report. Emissions must be determined according to any method specified for that process emissions type in 40 CFR Part 98, and expressed in metric tons of CO_2, CO_2 from bio-based feedstock, CH_4, N_2O, and total CO_2e as applicable. At facilities where a continuous emissions monitoring system (CEMS) is installed and operated according to federal, state or local requirements, process emissions may be reported in combination with

stationary combustion emissions, but fuel use by fuel type must be separately reported in the units specified below.

(4) ~~***Mobile Sources.*** The operator may elect to identify, calculate, and separately report facility CO_2, N_2O, and CH_4 emissions from mobile combustion. For those gases selected for voluntary reporting, the operator shall calculate mobile combustion emissions using the methods specified in section 95125(i).~~Identification of the methods chosen for determining emissions.

(5) ~~The operator shall separately calculate and report consumption of purchased or acquired electricity, heat, cooling or steam when specified in sections 95110 through 95115.~~Any facility operating data or process information used for the GHG emission calculations, including fuel use by fuel type, reported in million standard cubic feet for gaseous fuels, gallons for liquid fuels, short tons for solid fuels, and bone-dry short tons for biomass-derived solid fuels. If applicable, include high heat values and carbon content values used to calculate emissions.

(6) For facilities with on-site electricity generation or cogeneration, the information specified in section 95112(a)-(b) of this article.

(7) A signed and dated certification statement provided by the designated representative of the owner or operator, according to the requirements of 40 CFR §98.4(e)(1).

(b) Abbreviated emissions data reports submitted under this provision must be certified no later than June 1 of each calendar year. Subsequent revisions according to the requirements of 40 CFR §98.3(h) must be submitted only if cumulative errors are found to exceed 5 percent of total CO_2e emissions, or if error correction would cause the emissions total to exceed 25,000 metric tons of CO_2e, in which case a report that meets the full requirements of this article must be submitted.

(c) For abbreviated reports submitted under this provision, records must be kept according to the requirements of 40 CFR 98.3(g), except that a written GHG Monitoring Plan is not required.

(d) An abbreviated emissions data report is not subject to the third-party verification requirements of this article.

(e) *Reporting Deadlines.* Except as otherwise specified in this paragraph, each facility operator or supplier must submit an emissions data report for the previous calendar year no later than April 1 of each calendar year. Each electric power entity must submit an emissions data report for the previous calendar year no later than June 1 of each calendar year. The operator submitting an abbreviated report under the provisions of section 95103(a)-(d) must submit the abbreviated report no later than June 1 of each calendar year.

(f) *Verification Requirement and Deadlines.* Each reporting entity submitting an emissions data report for the previous calendar year that indicates emissions equaled or exceeded 25,000 metric tons of CO_2e, including CO_2 from biomass-

derived fuels and geothermal sources, and each reporting entity that has or has had a compliance obligation under the Cap-and-Trade Regulation in any year of the current three-year compliance period, must obtain third-party verification services for that report from a verification body that meets the requirements specified in Subarticle 4 of this article. Such services must be completed and a verification statement submitted by the verification body to the Executive Officer by September 1 each year for operators and suppliers, and by October 1 each year for electric power entities. Each reporting entity must ensure that this verification statement is submitted by the applicable deadline specified in this paragraph. Contracting with a verification body without providing sufficient time to complete the verification statement by the applicable deadline will not excuse the reporting entity from this responsibility. These requirements are additional to the requirements in 40 CFR §98.3(f).

(g) *Non-submitted/Non-verified Emissions Data Reports.* When a reporting entity that holds a compliance obligation under the Cap-and-Trade Regulation fails to submit an emissions data report or fails to obtain a positive or qualified positive verification statement by the applicable deadline, the Executive Officer shall develop an assigned emissions level for the reporting entity as set forth in section 95131(c)(5)(A)-(B).

(h) *Reporting in 2012.* For emissions data reports due in 2012, in cases where monitoring equipment and procedures were not in place in 2011 to enable reporting under the full specifications of this article, operators and suppliers must report 2011 emissions using monitoring and calculation methods that are applicable to them from 40 CFR Part 98. Electric power entities must report 2011 electricity transactions (MWh) and emissions (MT of CO_2e) under the full specifications of this article as applicable in 2012.

~~(6) **Emissions**~~ (i) *Calculation and Reporting* ~~**Procedures for**~~*of* De Minimis ~~**Sources**~~*Emissions*. ~~The~~A facility operator may ~~elect to~~ designate as *de minimis* ~~one or more sources that collectively produce~~a portion of GHG emissions, representing no more than 3 percent of ~~the~~a facility's total CO_2 equivalent emissions (including emissions from biomass-derived fuels and feedstock), not to exceed 20,000 metric ~~tonnes~~tons of CO_2 ~~equivalent emissions~~e. The operator may estimate ~~emissions for these~~ *de minimis* ~~sources~~emissions using alternative methods of the operator's choosing, subject to the concurrence of the verification ~~team~~body that the ~~use of such~~ methods ~~provides reasonable assurance that the emissions so designated and estimated do not~~used are reasonable, not biased toward significant underestimation or overestimation of emissions, and unlikely to exceed the ~~applicable *de minimis* limits. The operator shall~~*de minimis* limits. Where these emissions are required to be reported by 40 CFR Part 98, the operator must calculate and report them consistent with the report submitted to U.S. EPA under those requirements. The operator must separately identify and include in the emissions data report the emissions from designated *de minimis* sources. The

operator ~~shall~~must determine CO_2 equivalence according to the ~~100-year~~ global warming potentials provided in ~~Appendix A.~~Table A-1 of 40 CFR Part 98.

~~(7) The operator shall report information in the units of measurement specified in sections 95110 through 95115.~~

~~(8) ***Fuel Analytical Data Capture.*** When the applicable emissions estimation methodologies in sections 95110 through 95125 require periodic collection of fuel analytical data for an emissions source, the operator shall demonstrate every reasonable effort to obtain a fuel analytical data capture rate of 100 percent for each report year.~~

~~(A) If the operator is unable to obtain fuel analytical data such that more than 20 percent of emissions from a source cannot be directly accounted for, and the source for which data are missing is not subject to separate fuel analytical data capture requirements specified in 40 CFR Part 75 or Part 60, the emissions from that source shall be considered unverifiable for the report year.~~

~~(B) If the fuel analytical data capture rate is at least 80 percent but less than 100 percent for any emissions source identified in sections 95110 through 95125, and that source is not subject to separate fuel analytical data capture requirements specified in 40 CFR Part 75 or Part 60, the operator shall use the mean of the fuel analytical data results captured to substitute for the missing values for the period of missing data.~~

~~(9) ***Fuel Use Measurement Accuracy.*** The operator shall employ procedures for fuel use data measurements (mass or volume flow) used to calculate GHG emissions that quantify fuel use with an accuracy within ±5 percent. All fuel use measurement devices shall be maintained and calibrated in a manner and at a frequency required to maintain this level of accuracy. The operator shall make available to the verification team documentation to support this level of accuracy. The operator who measures solid fuels shall validate fuel consumption estimates with belt or conveyor scale calibrations conducted at least quarterly, and retain record of such calibrations.~~

~~(10) ***Procedure for Interim Fuel Analytical Data Collection.***~~

~~(A) In the event of an unforeseen breakdown of fuel analytical data monitoring equipment required for the emissions estimation methodologies in sections 95110 through 95125, the Executive Officer may authorize an operator to use an interim data collection procedure if the Executive Officer determines that the operator has satisfactorily demonstrated that:~~

1. The breakdown may result in a loss of more than 20 percent of the source's fuel data for the reporting year, such that emissions for the affected source could not be verified under the provisions of section 95103(a)(8)(A);
2. The fuel analytical data monitoring equipment cannot be promptly repaired or replaced without shutting down a process unit significantly affecting the facility operations, or that the monitoring equipment must be replaced and replacement equipment is not immediately available;
3. The interim procedure will not remain in effect longer than is reasonably necessary for repair or replacement of the malfunctioning data monitoring equipment; and
4. The request was submitted within 30 calendar days of the breakdown of the fuel analytical data monitoring equipment.

(B) An operator seeking approval of an interim data collection procedure must, within 30 days of the monitoring equipment breakdown, submit a written request to the Executive Officer that includes all of the following:

1. The proposed start date and end date of the interim procedure;
2. A detailed description of what data are affected by the breakdown;
3. A discussion of the accuracy of data collected during the interim procedure compared with the data collected under the operator's usual equipment-based method;
4. A demonstration that no feasible alternative procedure exists that would provide more accurate emissions data; and
5. A demonstration that the proposed interim procedure meets the criteria specified in section 95103(a)(10)(A).

(C) The Executive Officer may limit the duration of the interim data collection procedure or include other conditions of approval to ensure the criteria in section 95103(a)(10)(A) are met.

(D) Data collected pursuant to an approved interim data collection procedure shall be considered captured data for purposes of compliance with the capture rate requirements in section 95103(a)(8). When approving an interim data collection procedure, the Executive Officer shall determine whether the accuracy of data collected under the procedure is reasonably equivalent to data collected from properly functioning monitoring equipment, and if it is not, the relative accuracy to assign for purposes of assessing possible material misstatement under section 95131(b)(11) of this article.

(11) Where this article specifies a choice between use of a fuel-based calculation or use of a continuous emissions monitoring system (CEMS) to calculate CO_2 emissions, the operator shall make this choice and continue to use the method

chosen for all future emissions data reports. When an operator elects to install a new CEMS prior to January 1, 2011, the operator may report combustion emissions on the basis of the fuel-based calculation specified in this article for the 2008, 2009, and 2010 report years. The new CEMS shall be installed and operated according to requirements in section 95125(g), and become operational for purposes of emissions reporting by January 1, 2011.

(b) ***Reporting Schedule – Existing Facilities.*** Operators of the facilities and entities listed in section 95101(b), except as provided in section 95103(e), that are operational as of January 1, 2008, must submit emissions data reports to ARB in 2009 and each subsequent calendar year. Operators shall submit these reports as specified in the following schedule.

(1) The following operators subject to the requirements of this article shall submit a complete emissions data report to the ARB no later than April 1 of each calendar year beginning in 2009, for emissions occurring in the previous calendar year:

(A) Operators of general stationary combustion facilities, excluding oil and gas facilities with a NAICS code of 211111;

(B) Operators of electricity generating facilities and cogeneration facilities not under the operational control of any of the following: a retail provider, cement plant operator, petroleum refinery operator, hydrogen plant operator, or operator of an oil and gas facility with a NAICS code of 211111.

(2) The following operators subject to the requirements of this article shall submit a complete GHG emissions data report to the ARB no later than June 1 of each calendar year beginning in 2009, for emissions occurring in the previous calendar year:

(A) Retail providers;

(B) Marketers;

(C) Operators of general stationary combustion facilities within the oil and gas sector with a NAICS code of 211111;

(D) Operators of cement plants;

(E) Operators of petroleum refineries;

(F) Operators of hydrogen plants.

(c) ***Verification – Existing Facilities.*** Operators of all facilities subject to the reporting requirements of this article shall obtain verification services for emissions data reports submitted in 2010 and subsequent years from a verification body that meets the requirements of sections 95131 through 95133. Verification shall be obtained as provided in the following schedule.

(1) ***Annual Schedule.*** The following shall obtain verification of each annual emissions data report:

(A) Retail providers, marketers, and operators of petroleum refineries and hydrogen plants;

(B) Operators of general stationary combustion facilities in the oil and gas sector identified by NAICS code of 211111;

(C) Operators of electricity generating and cogeneration facilities that combust fossil fuels and have a total nameplate generating capacity ≥10 MW.

(2) ***Triennial Schedule.*** The following shall obtain verification of the emissions data report submitted in 2010, and shall obtain verification of the emissions data reports submitted every third year thereafter:

(A) Operators of cement plants; however, if any change in materials or operations occurs at a cement plant that requires a change in a permit filed with an air pollution control district or air quality management district, the operator of the cement plant shall obtain verification of the emissions data report that covers the first full calendar year following the permit change, in addition to the regular triennial schedule;

(B) Operators of electricity generating or cogeneration facilities that combust pure biomass fuels, or geothermal generating facilities;

(C) Operators of electricity generating or cogeneration facilities that have a total nameplate generating capacity <10 MW;

(D) Operators of general stationary combustion facilities, excluding oil and gas sector facilities identified by NAICS code 211111.

(3) ***Verification Opinion Due Dates.*** In the calendar years when verification is required, the verification body shall submit to the ARB the verification opinion specified in section 95131(c)(1) no later than six months after the deadlines specified in section 95103(b) for submitting emission reports.

(A) For operators having an emissions data report due April 1, as specified in section 95103(b)(1), the verification opinion must be submitted no later than October 1 of the same calendar year;

(B) For operators having an emissions data report due June 1, as specified in section 95103(b)(2), the verification opinion must be submitted no later than December 1 of the same calendar year.

(d) ***Reporting Schedule – New Facilities.*** Any operator described in section 95101(b) that commences operations at a new facility after January 1, 2008 shall submit an initial emissions data report for that facility based on emissions produced during the first full calendar year of operation. The emissions data report and a verification opinion shall be submitted during the year following the first full calendar year of operation according to the schedule in sections 95103(b) and (c), with reports for subsequent years due as required by the same schedule. This paragraph does not apply to changes in ownership, management, or operations at existing facilities.

(e) ***Cessation of Reporting After Reduced Emissions.***

(1) When the operation of a general stationary combustion facility, refinery, or hydrogen plant subject to the requirements of this article is changed such that the operator has reported less than 20,000 metric tonnes of CO_2 from combustion for three consecutive report years, the operator shall be exempted

~~from further reporting until CO_2 emissions from combustion again exceed 25,000 metric tonnes in any calendar year.~~

~~(2) When the operation of an electricity generating or cogeneration facility subject to this article is changed such that the operator has reported less than 2,000 metric tons of CO_2 for three consecutive report years, the operator shall be exempted from further reporting until CO_2 emissions again exceed 2,500 metric tonnes in any calendar year.~~

(j) *Calculating, Reporting, and Verifying Emissions from Biomass-Derived Fuels.* The operator or supplier must separately identify, calculate, and report all direct emission of CO_2 resulting from the combustion of biomass-derived fuels as specified in sections 95115 for facilities, and sections 95121-95122 for suppliers. Biomass-derived fuel emissions must be identified by the source of fuel as described in title 17, California Code of Regulations, section 95852.2. A biomass-derived fuel not listed in that section will be identified as an Other Biomass-Derived Fuel and the reporting entity will be required to hold a compliance obligation under title 17, California Code of Regulations, section 95852.1. For a fuel listed under title 17, California Code of Regulations, section 95852.2, reporting entities must also meet the verification requirements in section 95131(i) of this article, or the fuel must be identified as an Other Biomass-Derived Fuel and be subject to a compliance obligation under title 17, California Code of Regulations, section 95852.1. The responsibility for obtaining verification of a biomass-derived fuel falls on the entity that is claiming there is not a compliance obligation for the fuel, as indicated in section 95852.2 of the Cap-and-Trade Regulation.

(k) *Measurement Accuracy Requirement.* The operator or supplier submitting an emissions data report with fossil fuel emissions greater than or equal to 25,000 metric tons of CO_2e, and each operator or supplier with a compliance obligation under the Cap-and-Trade Regulation in any year of the current three-year compliance period, must meet the requirements of 40 CFR §98.3(i) for calibration and measurement device accuracy. The operator or supplier with infrequent outages as specified at 40 CFR §98.3(i)(6) who documents in the monitoring plan a calibration postponement after January 1, 2012 must submit to the Executive Officer a request for postponement, within 30 days of the postponement or the effective date of this article, whichever occurs last. The request must include an explanation of the reasons for the postponement, the date when the calibration will be completed, or a demonstration of meter accuracy in the absence of calibration. Such postponement will be subject to the approval of the Executive Officer.

(l) *Weekly Fuel Monitoring.* In addition to the requirements specified in 40 CFR §98.3(g)(5), as a part of the GHG Monitoring Plan the operator must monitor fuel measurement equipment and maintain records of its proper operation by recording fuel consumption quantities at least weekly, where such equipment is used to calculate GHG emissions. The records of fuel consumption must be sufficient for the application of the missing data substitution procedure in section 95129(d)(2) in the event that the use of that procedure becomes necessary.

(m) *Changes in Methodology.* Except as specified below, where this article permits a choice between different methods for the monitoring and calculation of GHGs, the operator or supplier must make this choice by January 1, 2013, and continue to use the method chosen for all future emissions data reports, unless the use of an alternative calculation method is approved in advance by the Executive Officer.

(1) The operator or supplier is permitted to permanently improve the emissions calculation method after January 1, 2013 through a change to a higher-tier monitoring or calculation method, such as the addition of a continuous emissions monitoring system.
(2) The operator or supplier is permitted to temporarily modify the emissions monitoring or calculation method when consistent with and necessary to comply with the missing data provisions of this article.
(3) When proposing a change in monitoring or calculation method, an operator or supplier must indicate why the change in method is being proposed, and provide a demonstration of differences in estimated emissions under the two methods.
(4) When permitted, a change in method must be made after the completion of monitoring for a data year, and not for a portion of a data year except where necessary to comply with section 95129 and other missing data substitution provisions of this article.

(n) *Addresses.* The following address shall be substituted for the addresses provided in 40 CFR §98.9 for both U.S. mail and package deliveries:

Executive Officer
Attn: Emission Inventory Branch
California Air Resources Board
P.O. Box 2815
Sacramento, CA 95812

NOTE: Authority cited: Sections 39600, 39601, 39607, 39607.4, 41511, 38510, and 38530, Health and Safety Code. Reference: Sections 39600, 41511, and 38530, Health and Safety Code.

§ 95104. ~~Greenhouse Gas~~ Emissions Data Report Contents and Mechanism.

The reporting entities specified in 95101 must develop, submit, and certify greenhouse gas emissions data reports to the Air Resources Board each year in accord with the following requirements.

(a) ***~~Emissions Data Report.~~*** ~~Operators subject to this article shall submit emissions data reports according to the schedule and requirements specified in section 95103, except as provided in section 95103(e). Emissions data reports shall include the~~

~~information below and the additional data specified in sections 95110 through 95115, as applicable.~~*General Contents.* In addition to the items specified at 40 CFR §98.3(c), each reporting entity must include in the emissions data report the following California information: ARB identification number, air basin, air district, county, and geographic location.

~~(1) Facility name, identification number, physical address, mailing address, location, NAICS code;~~
~~(2) A description of facility geographic location;~~
~~(3) Name and contact information including email address and telephone number, of the operator submitting the emissions report and the person primarily responsible for preparing and submitting the emissions report;~~
~~(4) The report year;~~
~~(5) The direct emissions, electricity transactions information, and other data specified in sections 95110 through 95115 as applicable to the operator, including emissions occurring during routine maintenance, start-ups, shutdowns, upsets and downtime;~~
~~(6) Indirect energy consumed for electricity, heat, steam, and cooling when required for the facility as specified in sections 95110 through 95115;~~
~~(7) Efficiency metrics when required for the facility as specified in sections 95110 through 95115;~~
~~(8) The parent company or companies of the operator, along with:~~
~~(A) A list of all facilities and offices in California owned or operated by that parent company or companies, directly or through a subsidiary, that emit direct GHG emissions from combustion that is not for the purpose of facility space heating, including facilities and offices not subject to the requirements of this article;~~
~~(B) Contact information for the facilities and offices provided in section 95104(a)(8)(A), including physical addresses, e-mail addresses if available, and telephone numbers;~~
~~(C) The operator may elect to have information required by sections 95104(a)(8)(A) (B) submitted separately by the parent company for all facilities under the ownership or operational control of the parent company or its subsidiaries;~~
~~(D) The operator may also elect to provide a single contact person, e-mail, and phone contact for all facilities listed under the requirements of 95104(a)(8)(A) (B);~~
~~(E) Information provided under section 95104(a)(8) is not subject to the verification requirements of this article.~~

~~(9) Emission factors developed or measured by the operator using approved source testing as provided under sections 95125(b)(4) or 95125(h)(3). Emission factors shall be provided in units of emissions per amount of fuel consumed, where fuel is reported in units of either scf for gases, gallons for liquids, short tons for non-biomass solids, or bone dry tons for biomass-derived solid fuels.~~

~~(10) A signed and dated statement provided by the operator that the report has been prepared in accordance with this article, and that the statements and information contained in the emissions data report are true, accurate, and complete.~~

(b) ~~***Maintaining the GHG Inventory Program.*** To facilitate annual compilation of the emissions data report, the operator shall maintain a greenhouse gas inventory program that ensures that emissions calculations and electricity transactions information are transparent, accurate, and independently verifiable. The operator shall establish, document, implement, and maintain data acquisition and handling activities for the calculation and reporting of greenhouse gas emissions. Such activities shall include measuring, monitoring, analyzing, recording, processing and calculating the parameters specified by this article.~~Designated Representative. *Each reporting entity must designate a reporting representative and adhere to the requirements for this representative at 40 CFR §98.4. Operators and suppliers with a reporting obligation under 40 CFR Part 98 must designate the same reporting representative as named under those requirements.*

(c) ~~***Data Completeness.*** The operator shall establish, document, implement and maintain a system that provides clarity, transparency, and completeness of data sufficient to facilitate replication of the emissions and electricity transactions information reported as specified by this article. The operator shall make every reasonable effort to complete emissions data reports that contain no material misstatement and are in conformance with the emission calculation methodologies and factors specified by this article. The operator shall implement systems of internal audit, quality assurance, and quality control for the reporting program and the data reported.~~*Corporate Parent and NAICS Codes.* Each reporting entity must submit information to meet the requirements specified in amendments to 40 CFR Part 98 on Reporting of Corporate Parent Information, NAICS Codes and Cogeneration, as promulgated by U.S. EPA on September 22, 2010.

(d) ~~***Revisions.*** The operator may revise a submitted emissions data report under the circumstances specified in section 95104(d)(1)-(3). The operator shall maintain documentation to support any revisions made to a previously submitted emissions data report. Documentation for all emissions data report revisions shall be retained by the operator for five years, as specified in section 95105.~~*Energy Purchases.* The operator must include in the emissions data report the facility's electricity purchases (kWh), and steam, heat, and cooling purchases (mmBtu), each by name and ARB identification number of the provider. The operator must report this information for the calendar year covered by the emissions data report, pro-rating purchases as necessary to include information for the full months of January and December.

~~(1) If during the course of receiving verification services and prior to completion of a verification opinion an operator chooses to make a correction or improvement to the report;~~

~~(2) If an operator wishes to correct or improve an emissions data report not subject to verification, provided those changes are documented and approved by ARB;~~

~~(3) If, within five years of submittal, an operator wishes to correct or improve an emissions data report that has received a positive verification opinion, in which case the revision must also be made subject to verification.~~

(e) *Reporting Mechanism.* Reporting entities~~The operator~~ shall submit emissions data reports, and any revisions to the reports, through the California Air Resources Board's (ARB) Greenhouse Gas Reporting Tool, or any other reporting tool approved by the Executive Officer that will guarantee transmittal and receipt of data required by ARB's Mandatory Reporting Regulation and Cost of Implementation Fee Regulation.

NOTE: Authority cited: Sections 39600, 39601, 39607, 39607.4, 41511, 38510, and 38530, Health and Safety Code. Reference: Sections 39600, 41511, and 38530, Health and Safety Code.

§ 95105. ~~Document Retention and Record Keeping Requirements.~~ Recordkeeping Requirements.

Each reporting entity that is required to report greenhouse gases under this article, except as provided in section 95103(c), must keep records as required by 40 CFR §98.3(g)-(h) with the following qualifications.

(a) ~~The operator shall establish and maintain procedures for document retention and record keeping. The operator shall retain documents regarding the design, development and maintenance of the GHG inventory, in paper, electronic or other usable format, for a period of not less than five years following submission of each~~*Duration.* Reporting entities with a compliance obligation under the Cap-and-Trade Regulation in any year of the current three-year compliance period must maintain all records specified in 40 CFR §98.3(g), and records associated with revisions to emissions data reports as provided under 40 CFR §98.3(h), for a period of ten years from the date of emissions data report certification. The retained documents, including GHG emissions data~~, shall~~ and input data, must be sufficient to allow for ~~the~~ verification of each emissions data report. Reporting entities that do not have a compliance obligation under the Cap-and-Trade Regulation during any year of the current three-year compliance period must maintain such records for a period of five years from the date of certification.

(b) ~~Upon request by ARB, the operator shall provide to ARB within 20 working days all documents, including data, used to develop an emissions data report.~~
ARB Requests for Records. Copies of any records or other materials maintained under the requirements of 40 CFR Part 98 or this article must be made available to the Executive Officer upon request, within twenty days of receipt of such request by the designated representative of the reporting entity.

(c) ~~In addition to information submitted as part of the emissions data report, each operator shall retain, at a minimum, the following information for at least five years after the submission of the report:~~ *GHG Monitoring Plan.* Each reporting entity that reports under 40 CFR Part 98, and each reporting entity with a compliance obligation under the Cap-and-Trade Regulation in any year of the current three-year compliance period, must complete and retain for review by a verifier or ARB a written GHG Monitoring Plan that meets the requirements of 40 CFR §98.3(g)(5) and includes the following elements:

~~(1) The list of all sources included in the emission es~~timates;
~~(2) The~~
(1) All fuel use ~~data~~measurement devices used ~~to calculate~~for emissions ~~for each source, categorized by process and fuel or material type;~~
~~(3) Documentation of the process for collecting fuel use data for the facility and its sources;~~
~~(4) Any GHG emissions calculations and methods used;~~
~~(5) All emission factors used for emission estimates, including documentation for any factors not provided by ARB;~~
~~(6) Any facility or other input data used for emission estimates;~~
~~(7) Documentation of biomass fractions for specific fuels;~~
~~(8) Record of electric power purchase and sale transactions, including imports and exports of power into and from California;~~
~~(9) The fuel use data, emissions, or other data submitted to the ARB under this article including the emissions data report;~~calculations must be clearly identified, and the plan must indicate how data from these devices are incorporated into the emissions data report;
(2) Original equipment manufacturer (OEM) documentation, or other documentation that identifies instrument accuracy and required maintenance and calibration requirements for all measurement devices used in the calculation of GHG emissions.
~~(10) Names and documentation of key facility~~(3) Training practices for personnel involved in ~~emissions calculating and reporting~~GHG monitoring, including documented training procedures, and training materials;
~~(11) Any other information that is required for the verification of the emissions data report.~~
~~(12) A log to be prepared for each reporting year, beginning January 1, 2009, documenting all procedural changes made in GHG accounting methods and changes to instrumentation critical to GHG emissions determination.~~

~~(d) For measurement based methodologies, each operator shall retain the following information for at least five years after the submission of the emissions data report:~~

~~(1) The list of all emission sources monitored;~~
~~(2) Collected monitoring data;~~

~~(3) The data used to assess the accuracy of emissions from each emissions source, categorized by process;~~
~~(4) Quality assurance and quality control information including information regarding any measurement gaps;~~
~~(5) The data used for the corroborating calculations;~~
~~(6) A detailed technical description of the continuous measurement system, including documentation of any findings and approvals by federal, State or local agencies;~~
~~(7) Raw and aggregated data from the continuous measurement system; including documentation of changes over time and the log book on tests, down-times, calibrations, servicing and maintenance;~~
~~(8) Documentation of any changes in continuous measurement systems.~~
(4) Copies of methodologies used for all fuel analyses.

NOTE: Authority cited: Sections 39600, 39601, 39607, 39607.4, 41511, 38510, and 38530, Health and Safety Code. Reference: Sections 39600, 41511, and 38530, Health and Safety Code.

§ 95106. Confidentiality.

(a) Emissions data submitted to the ARB under this article is public information and shall not be designated as confidential. Data reported to U.S. EPA under 40 CFR Part 98 which is determine to be non-confidential by U.S. EPA shall be considered public information by ARB.

(b) Any entity submitting information to the ~~ARB~~Executive Officer pursuant to this article may ~~designate~~claim such information as "confidential" by clearly identifying such information as "confidential." Any claim of confidentiality by an entity submitting information must be based on the entity's belief that the information marked as confidential is either~~that is not emissions data as confidential because it is a~~ trade secret or otherwise exempt from public disclosure under the California Public Records Act (Government Code section 6250 et seq.). All such requests for confidentiality shall be handled in accordance with the procedures specified in title 17, California Code of Regulations, sections 91000 to 91022.

NOTE: Authority cited: Sections ~~38580,~~ 39600, 39601, 39607, 39607.4, 41511, 38510, and 38530, Health and Safety Code. Reference: Sections ~~38580,~~ 39600, 41511, and 38530, Health and Safety Code.

§ 95107. Enforcement.

~~(a) Knowing submission of false information, with intent to deceive, to the Executive Officer or a verification body, shall constitute a single, separate violation of the requirements of this article for each day after the information has been received by the Executive Officer.~~

~~(b) Failure to submit~~(a) Each day or portion thereof that any report ~~or to include in a report all information required by this article, or late submittal of any report, shall constitute a single, separate violation of this article for each day that the report has not been submitted beyond the specified reporting date. For the~~required by this article remains unsubmitted, is submitted late, or contains information that is incomplete or inaccurate within the level of reproducibility of a test or measurement method is a separate violation. For purposes of this section, ~~"~~"report"~~"~~ means any emissions data report, verification ~~opinion~~statement, or other ~~document~~record required to be submitted to the Executive Officer by this article.

(b) Except as otherwise provided in this section, each day or portion thereof in which any other violation of this article occurs is a separate offense.

(c) Each metric ton of CO_2e emitted but not reported as required by this article is a separate violation.

(d) Each failure to measure, collect, record or preserve information needed for the calculation of emissions as required by this article or that this article otherwise requires be measured, collected, recorded or preserved constitutes a separate violation of this article.

(e) The Executive Officer may revoke or modify any Executive Order issued pursuant to this article as a sanction for a violation of this article.

(f) The violation of any condition of an Executive Order that is issued pursuant to this article is a separate violation.

(g) Penalties may be assessed for any violation of this article pursuant to Health and Safety Code section 38580.

(h) Any violation of this article may be enjoined pursuant to Health and Safety Code section 41513.

NOTE: Authority cited: Sections ~~38580,~~ 39600, 39601, 39607, 39607.4, 41511, 38510, and 38530, Health and Safety Code. Reference: Sections ~~38580,~~ 39600, 41511, and 38530, Health and Safety Code.

§ 95108. Severability.

Each part of this article shall be deemed severable, and in the event that any provision of this article is held to be invalid, the remainder of this article shall continue in full force and effect.

NOTE: Authority cited: Sections 39600, 39601, 39607, 39607.4, 41511, 38510, and 38530, Health and Safety Code. Reference: Sections 39600, 41511, and 38530, Health and Safety Code.

§ 95109. ~~Incorporation by Reference.~~ Standardized Methods.

~~The following documents are incorporated by reference into this article. These materials are incorporated as they exist on the date this article is adopted.~~

~~(a) American Society for Testing and Materials (ASTM) D1826-94 (Reapproved 2003), ASTM D3588-98 (Reapproved 2003), ASTM D4891-89 (Reapproved 2006), ASTM D240-02 (Reapproved 2007), ASTM D4809-00 (Reapproved 2005), ASTM 5373-02 (Reapproved 2007), ASTM D5291-02 (Reapproved 2007), ASTM D3238-95 (Reapproved 2005), ASTM D2502-04, ASTM D2503-92 (Reapproved 2002), ASTM D1945-03, ASTM D1946-90 (Reapproved 2006), ASTM D6866-06a, ASTM D388-05, ASTM D5468-02 (Reapproved 2007), ASTM D240-87 (Reapproved 1991), ASTM D5865-07a, ASTM Specification D396-07, ASTM Specification D975-07b.~~

~~(b) *California Implementation Guidelines for Estimating Mass Emissions of Fugitive Hydrocarbon Leaks at Petroleum Facilities*, California Air Pollution Control Officers Association (CAPCOA) and California Air Resources Board (ARB), February 1999.~~

~~(c) *Control of Emissions from Refinery Flares*, Rule 1118, South Coast Air Quality Management District, Amended November 4, 2005.~~

~~(d) *U.S. EPA TANKS Version 4.09D*, US Environmental Protection Agency, October 2005.~~

~~(e) Gas Processors Association (GPA) Standard 2261-00, Revised 2000.~~

(a) Entities that are required to report greenhouse gas emissions pursuant to this article must use either those standardized methods and materials listed in 40 CFR §98.7, or another similar method published by an organization listed in 40 CFR §98.7 that is applicable to the analysis being conducted. For gaseous fuels, fuel characteristics may be determined using chromatographic analysis as specified in 40 CFR §98.34(a)(6) and §98.34(b)(5). All methods used must be documented in the GHG Monitoring Plan that is as required by section 95105(c).

(b) Alternative test methods that are demonstrated to the satisfaction of the Executive Officer to be equally or more accurate than the methods in section 95109(a) may be used upon written approval by the Executive Officer.

NOTE: Authority cited: Sections 39600, 39601, 39607, 39607.4, 41511, 38510, and 38530, Health and Safety Code. Reference: Sections 39600, 41511, and 38530, Health and Safety Code.

Subarticle 2. Requirements for the Mandatory Reporting of Greenhouse Gas Emissions from Specific Types of Facilities, Suppliers, and Entities

§ 95110. ~~Data Requirements and Calculation Methods for Cement Plants.~~Cement Production.

The operator of a facility who is required to report under section 95101 of this article, and who is not eligible for abbreviated reporting under section 95103(a), must comply with Subpart H of 40 CFR Part 98 (§§98.80 to 98.88) in reporting annual stationary combustion and process emissions from cement production to ARB, except as otherwise provided in this section.

(a) ~~***Greenhouse Gas Emissions Data Report.*** The operator of a cement plant specified in section 95101(b) shall include the following information in the emissions data report for each report year.~~ *CO_2 from Fossil Fuel Combustion.* When calculating CO_2 emissions from fuel combustion, the operator must use a method in 40 CFR §98.33(a)(1) to §98.33(a)(4) as specified by fuel type in section 95115 of this article.

~~(1) Total emissions, including:~~
~~(A) Total CO_2 emissions (metric tonnes),~~
~~(B) Total CH_4 emissions (metric tonnes), and~~
~~(C) Total N_2O emissions (metric tonnes).~~

~~(2) Process CO_2 emissions from cement manufacturing using the following calculation methods:~~
~~(A) Clinker based methodology for CO_2 estimates shall include:~~
~~1. Clinker emission factor (kg CO_2/metric tonne clinker) including:~~
~~a. Quantity of clinker produced (metric tonnes),~~
~~b. Lime (CaO) content of clinker (percent),~~
~~c. Magnesium Oxide (MgO) content of clinker (percent),~~
~~d. Non-carbonate CaO (percent), and~~
~~e. Non-carbonate MgO (percent);~~
~~2. Cement kiln dust (CKD) emission factor (kg CO_2/metric tonne clinker) including,~~
~~a. Plant specific CKD calcination rate (unitless), and~~
~~b. Quantity of CKD discarded (metric tonnes); and~~
~~3. CO_2 emissions from clinker production (metric tonnes).~~

~~(B) Total organic carbon (TOC) content in raw materials including:~~
~~1. Amount of raw material consumed in the report year (metric tonnes),~~
~~2. Organic carbon content of raw material (percent), and~~
~~3. CO_2 emissions from TOC in Raw Materials (metric tonnes).~~

~~(3) Stationary combustion emissions, including:~~

~~(A) Fuel consumption by fuel type, separately for kiln and non-kiln units, reporting in units of million standard cubic feet for gases, gallons for liquids, short tons for non-biomass solids, and bone dry short tons for biomass-derived solid fuels;~~

~~(B) Average carbon content as a percent by fuel type if measured or provided by fuel supplier;~~

~~(C) Average high heat value (HHV) by fuel type if measured or provided by fuel supplier, reporting in units of MMBtu per fuel unit as specified in section 95110(a)(3)(A);~~

~~(D) CO_2 emissions by fuel type (metric tonnes), separately for kiln and non-kiln units, including separately calculated and identified CO_2 emissions from biomass-derived fuels (metric tonnes);~~

~~(E) CH_4 emissions by fuel type (metric tonnes); and,~~

~~(F) N_2O emissions by fuel type (metric tonnes).~~

~~(4) Fugitive emissions, including:~~

~~(A) Coal consumption by coal type (short tons),~~

~~(B) Emission factor (million standard cubic feet (scf) CH_4/metric tonne), and~~

~~(C) CH_4 emissions from coal storage (metric tonnes).~~

~~(5) Indirect energy usage, including:~~

~~(A) Electricity purchases from each electricity provider (kWh), and~~

~~(B) Steam, heat, and cooling purchases from each energy provider (Btu).~~

~~(6) Efficiency metrics, using both of the following calculation methods:~~

~~(A) CO_2 emissions per metric tonne of cementitious product, including:~~

~~1. Amount of own clinker consumed (metric tonnes),~~

~~2. Amount of clinker added to stock (metric tonnes),~~

~~3. Amount of clinker sold directly (metric tonnes),~~

~~4. Amount and type of clinker substitutes consumed for blending (metric tonnes), and~~

~~5. Amount and type of cement substitutes consumed for blending (metric tonnes).~~

~~(B) CO_2 emissions per metric tonne of clinker, including:~~

~~1. Amount of own clinker consumed (metric tonnes),~~

~~2. Amount of clinker added to stock (metric tonnes), and~~

~~3. Amount of clinker sold directly (metric tonnes).~~

(b) ~~**Calculation of CO_2, N_2O, and CH_4 Emissions.** *Operators of cement plants shall calculate emissions and indirect energy usage for each source as specified in this section.*~~ *Monitoring, Data and Records.* For each emissions calculation method chosen under section 95110(a), the operator must meet the applicable requirements for monitoring, missing data procedures, data reporting, and records retention that are specified in 40 CFR §98.34 to §98.37, except as modified in sections 95110(c), 95115, and 95129 of this article.

~~(1) ***Total CO_2 Emissions.*** Operators of cement plants shall calculate total CO_2 emissions using either (A) or (B) below.~~

~~(A) Continuous emissions monitoring systems (CEMS) as specified in section 95125(g). Operators of cement plants that measure CO_2 emissions using CEMS shall also report fuel usage by fuel type.~~

~~(B) Process CO_2 emissions from cement manufacturing as specified in section 95110(c) and stationary combustion CO_2 emissions as specified in section 95110(d).~~

~~(2) ***N_2O and CH_4 Emissions.*** Operators of cement plants shall calculate total N_2O and CH_4 emissions from fuel combustion as specified in section 95125(b).~~

~~(3) ***Fugitive Emissions.*** Operators of cement plants shall calculate fugitive CH_4 emissions from coal fuel storage as specified in section 95125(j).~~

~~(4) ***Indirect Energy Usage.*** Operators of cement plants shall calculate indirect electricity and thermal energy purchased or acquired and consumed as specified in sections 95125(k)-(l).~~

~~(5) ***Electricity Generating Units.*** Operators of cement plants with electricity generating units subject to the requirements of this article shall also meet the requirements of section 95111.~~

~~(6) ***Cogeneration.*** Operators of cement plants with cogeneration systems subject to the requirements of this article shall meet the requirements of section 95112.~~

~~(7) ***Efficiency Metrics.*** Operators of cement plants shall calculate CO_2 emissions per metric tonne of cementitious product and per metric tonne of clinker as specified in section 95110(e).~~

(c) ~~***Process CO_2 Emissions from Cement Manufacturing.*** Operators of cement plants shall calculate CO_2 emissions from clinker production using the Clinker-Based Methodology as specified in section 95110(c)(1). Operators shall also calculate CO_2 process emissions from the total organic carbon (TOC) content in raw materials as specified in section 95110(c)(2).~~ *Missing Data Substitution Procedures.* The operator must comply with 40 CFR §98.85 when substituting for missing data, except as otherwise provided in paragraphs (1)-(3) below.

(1) ~~**Clinker-Based Methodology.** Operators of cement plants shall calculate CO_2 emissions from clinker production using a plant-specific clinker emission factor and a plant-specific cement kiln dust (CKD) emission factor as specified in this section.~~ To substitute for missing data for emissions reported under section 95115 of this article (stationary combustion units and units using continuous

emissions monitoring systems), the operator must follow the requirements of section 95129 of this article.

~~*Clinker-Based Methodology*~~

~~CO_2 Emissions (metric tonnes) = [(Cli) * (EF_{Cli})] + [(CKD) * (EF_{CKD})]~~

~~Where:~~
~~Cli = Quantity of clinker produced, metric tonnes~~
~~EF_{Cli} = Clinker emission factor, metric tonnes CO_2/metric tonne clinker computed as specified in section 95110(c)(1)(A)~~
~~CKD = Quantity CKD discarded, metric tonnes~~
~~EF_{CKD} = CKD emission factor, computed as specified in section 95110(c)(1)(B)~~

(A) ~~***Clinker Emission Factor (EF_{Cli}).*** Cement plant operators shall calculate a plant-specific clinker emission factor for each report year based on the percent of measured CaO and MgO content in the clinker and adjusted to account for non-carbonate CaO and MgO using the Clinker Emission Factor equation specified in this section, 95110(c)(1)(A). Each fraction of non-carbonate sources (e.g., steel slag, calcium silicates or fly ash) of CaO and MgO shall be subtracted from the total amount of CaO and MgO content of the clinker.~~

~~*Clinker Emission Factor:*~~

~~EF_{Cli} = [(CaO content – non-carbonate CaO) * Molecular ratio of CO_2/CaO] + [(MgO Content – non-carbonate MgO) * Molecular Ratio of CO_2/MgO]~~

~~Where:~~
~~CaO Content (by weight) = CaO content of Clinker (%)~~
~~Molecular Ratio of CO_2/CaO = 0.785~~
~~MgO Content (by weight) = MgO content of Clinker (%)~~
~~Molecular Ratio of CO_2/MgO = 1.092~~
~~Non-carbonate CaO (by weight) = Non-carbonate CaO of Clinker (%)~~
~~Non-carbonate MgO(by weight) = Non-carbonate MgO of Clinker (%)~~

(B) ~~***CKD Emission Factor.*** Operators of cement plants that generate CKD and do not recycle the CKD back to the kiln shall calculate a plant-specific CKD emission factor. The CKD emission factor shall be calculated using the CKD Emission Factor equation (EF_{CKD}) and the Plant-specific CKD Calcination Rate (d) equation specified in this section (95110(c)(1)(B).~~

~~*CKD Emission Factor*~~

~~Where:~~
~~EF_{CKD} = CKD Emission Factor~~
~~EF_{Cli} = Clinker Emission Factor~~
~~d = CKD Calcination Rate~~

~~*Plant-specific CKD Calcination Rate*~~

~~d =~~

~~Where:~~
~~= weight fraction of carbonate CO_2 in the CKD~~
~~= weight fraction of carbonate CO_2 in the raw material~~

(2) ~~***TOC Content in Raw Materials.*** Operators of cement plants shall calculate CO_2 process emissions from the TOC content in raw materials by applying an assumed 0.2 percent organic carbon factor to the amount of raw material consumed then converting from carbon to CO_2 using the equation below.~~ If data for the carbonate content of clinker or cement kiln dust as required by 40 CFR §98.83(d) are missing, and a new analysis cannot be undertaken, the operator must apply a substitute value according to the procedures in paragraphs (A)-(C) below.

(A) If the data capture rate is at least 90 percent for the data year, the operator must substitute each missing value using the best available estimate of the parameter, based on all available process data.

(B) If the data capture rate is at least 80 percent but not at least 90 percent for the data year, the operator must substitute each missing value with the highest quality assured value recorded for the parameter during the given data year, as well as the two previous data years.

(C) If the data capture rate is less than 80 percent for the data year, the operator must substitute each missing value with the highest quality assured value recorded for the parameter in all records kept according to section 95105(a).

~~*TOC Content in Raw Materials*~~

~~CO_2 emissions = ($TOC_{R.M.}$) * (R.M.) * (3.664)~~

~~Where:~~
~~$TOC_{R.M}$ = 0.2% = Organic carbon content of raw material (%)~~
~~R.M. = The amount of raw material consumed (metric tonnes/yr)~~
~~3.664 = The CO_2 to carbon molar ratio~~

(3) For each missing value of the monthly raw material consumption or monthly clinker production, the operator must apply a substitute value according to paragraphs (A)-(B) below.

(A) If the data capture rate is at least 80 percent for the data year, the operator must substitute each missing value according to 40 CFR §98.85(c) or 40 CFR §98.85(d), as applicable.

(B) If the data capture rate is less than 80 percent for the data year, the operator must substitute each missing value with the maximum tons of clinker per day capacity of the system or the maximum tons per day raw material throughput of the kiln, as applicable, and the number of days per month.

(4) The operator must document and retain records of the procedure used for all missing data estimates pursuant to the recordkeeping requirements of section 95105.

(d) **~~Stationary Combustion CO_2 Emissions.~~** ~~*Operators of cement plants shall calculate stationary combustion CO_2 emissions at cement kiln and non-kiln units separately for the quantity and type of each fuel combusted during each report year as specified in this section.*~~ *Additional Data to Support Benchmarking.* In addition to the information required by 40 CFR §98.86, the operator must report the additional parameters provided in paragraphs (1)-(2) below whether or not a CEMS is used to measure CO_2 emissions.

(1) ~~Natural Gas and Associated Gas: Operators of cement plants that combust natural gas and associated gas shall calculate CO_2 emissions resulting from the combustion of natural gas and associated gas using the method provided in section 95125(c) or section 95125(d).~~ Annual quantity of clinker substitute consumed for blending, by type (short tons).

(2) ~~Coal or Petroleum Coke: Operators of cement plants that combust coal or petroleum coke shall calculate CO_2 emissions using the method provided in section 95125(d). Operators of cement plants shall measure and record weekly~~

~~coal consumption.~~ Annual quantity of cement substitute consumed, by type (short tons).

~~(3) Other Fossil Fuels: Operators of cement plants that combust middle distillates (such as diesel, fuel oil, or kerosene), residual oil, or LPG (such as ethane, propane, isobutene, n-Butane, or unspecified LPG) shall calculate CO_2 emissions using the method provided in section 95125(c) or section 95125(d).~~

~~(4) Refinery Fuel Gas: Operators of cement plants that combust refinery gas, still gas, or process gas shall calculate CO_2 emissions using the method provided in section 95125(c).~~

~~(5) Landfill Gas or Biogas: Operators of cement plants that combust landfill gas or biogas from waste water treatment shall calculate CO_2 emissions using the method provided in section 95125(c) or section 95125(d).~~

~~(6) Biomass Solids: Operators of cement plants that combust biomass shall calculate CO_2 emissions using the method provided in section 95125(a), section 95125(c), section 95125(d) or section 95125(h)(3).~~

~~(7) Waste-Derived Fuels: Operators of cement plants that combust waste-derived fuels including municipal solid waste shall calculate CO_2 emissions using the method provided in section 95125(c), or section 95125(d), or section 95125(h)(3).~~

~~(8) Co-Firing of Fuels: Operators of cement plants that co-fire more than one fuel shall calculate CO_2 emissions separately for each fuel type using methods provided in sections 95125(a) and (c)-(e) as specified by fuel type in sections 95110(d)(1)-(7) and 95110(d)(9). Operators that co-fire waste-derived fuels that are partly biomass but not pure biomass with other fuels, shall determine the biomass-derived portion of total CO_2 emissions resulting from the combustion of the co-fired fuels, using the method specified in section 95125(h)(2), if applicable.~~

~~(9) Start-Up Fuels: Operators of cement plants that primarily combust biomass-derived fuels but that combust fossil fuels for start-up, shut-down, or malfunction operating periods only, shall report CO_2 emissions from the fossil fuels using methodologies in section 95125(a) or methods specified in this section by fuel type.~~

~~(e) ***Efficiency Metrics.*** Cement plant operators shall calculate for the report year the CO_2 emissions generated per metric tonne of cementitious product and CO_2 emissions generated per metric tonne of clinker using the efficiency metric equations specified in this section, 95110(e).~~

~~(1) *CO_2 Emissions per metric tonne of Cementitious Product*~~

~~CO_2 emissions~~

(2) ~~*CO_2 Emissions per metric tonne of Clinker* CO_2 emissions~~

NOTE: Authority cited: Sections 39600, 39601, 39607, 39607.4, 41511, 38510, and 38530, Health and Safety Code. Reference: Sections 39600, 41511, and 38530, Health and Safety Code.

§ 95111. Data Requirements and Calculation Methods for ~~Electricity Generating Facilities, Retail Providers and Marketers~~Electric Power Entities.

Any electric power entity who is required to report under section 95101 of this article must comply with the following requirements when reporting to ARB.

~~(a) ***Electricity Generating Facilities.*** The operator of an electricity generating facility specified in section 95101(b) shall include the following information in the greenhouse gas emissions data report for each report year and shall meet the requirements specified in sections 95111(c) (i) as applicable to the facility when calculating emissions for inclusion in the report.~~

~~(1) For each facility, operators shall include:~~

~~(A) ARB designated facility identification number (ID), nameplate generating capacity in megawatts (MW), and net power generated in the report year in megawatt hours (MWh);~~

~~(B) Fuel consumption by fuel type, reporting in units of million standard cubic feet for gases, gallons for liquids, short tons for non-biomass solids, and bone dry short tons for biomass-derived solid fuels;~~

~~(C) Average high heat value by fuel type, reporting in units of MMBtu per unit of fuel as specified in section 95111(a)(1)(B), if measured, based on values measured by the operator or the fuel supplier as specified in section 95125(c)(1)(A)-(C). If high heat value is not measured by the operator or available from the fuel supplier, then the operator shall report steam produced in MMBtu. The operator may elect to convert pounds of steam into MMBtu using the method provided in section 95125(h)(1)(B). The operator shall include boiler efficiency, if known;~~

~~(D) Average carbon content, as a percent, by fuel type, if measured, based on values measured by the operator or the fuel supplier as specified in section 95125(d);~~

~~(E) CO_2, N_2O, and CH_4 emissions from stationary combustion in metric tonnes as specified~~

(a) *General Requirements and Content for GHG Emissions Data Reports for Electricity Importers and Exporters.*

(1) *Greenhouse Gas Emissions.* The electric power entity must report GHG emissions separately for each category of delivered electricity required, in metric tons of CO_2 equivalent (CO_2e), according to the calculation methods in section 95111(~~c) (d) by fuel type;~~b).

~~(F) Process CO_2 emissions from acid gas scrubbers or acid gas reagent used in the combustion source, if applicable, in metric tonnes;~~

(2) *Delivered Electricity.* The electric power entity must report delivered electricity in MWh, and must also separately report all imported electricity from unspecified sources by first point of receipt, and all imported electricity from each specified source.

~~(G) Fugitive CH_4 emissions from coal storage from coal-fired facilities, if applicable, in metric tonnes;~~

(3) *Imported Electricity from Unspecified Sources.* When reporting imported electricity from unspecified sources, the electric power entity must aggregate electricity deliveries and associated GHG emissions by first point of receipt. The electric power entity also must report the following:

~~(H) Fugitive emissions of HFC related to the operation of cooling units that support power generation, if applicable, in kilograms;~~

(A) The standardized acronym or code and the full name for the first point of receipt and the jurisdiction in which it is located;

(B) The amount of electricity from unspecified sources as measured at the first point of delivery in California; and,

(C) Whether transmission losses are made up in other electricity deliveries reported or from California sources. Transmission losses must be reported as required in section 95111(b).

~~(I) Fugitive CO_2 emissions from geothermal facilities, if applicable, in metric tonnes;~~

(4) *Imported Electricity from Specified Facilities or Units.* When reporting imported electricity from specified facilities or units, the electric power entity must aggregate electricity deliveries and associated GHG emissions by facility or unit, as applicable.

~~(J) Fugitive SF_6, in kilograms, emitted from equipment that is located at the facility and that the operator is responsible for maintaining in proper working order. Operators of multiple facilities or operators subject to the requirements in section 95111(b)(2)(A) may aggregate SF_6 emissions for all sources or any subset of sources;~~

(A) If the electric power entity holds a contract for a specified percentage of a facility's or unit's generation in the report year, the electric power entity must include electricity purchased or sold as being from a partially or fully owned facility or unit and meet the same requirements for partially or fully owned facilities or units in this section.

(B) Claims of specified sources of imported electricity must meet the requirements in section 95111(g) and include the following information:

~~(K) For facilities located inside California, wholesale sales (MWh) exported directly out-of-state, if known, that are additional to electricity transactions~~

~~reported as specified in section 95111(b)(2)(E). Sales shall be aggregated by counterparty and measured at the busbar. The operator shall report the region of destination as Pacific Northwest (PNW) or Southwest (SW).~~

1. Total facility or unit gross and net generation;
2. For specified deliveries from facilities or units that report GHG emissions to ARB or to U.S. EPA pursuant to 40 CFR Part 98, whether GHG emissions associated with net power generated exceed 1100 lbs CO_2e/MWh;
3. The amount of imported electricity from specified facilities or units as measured at the busbar; and
4. For imported electricity deliveries from specified facilities or units where measurements at the busbar are not known, the amount of imported electricity as measured at the first point of delivery in California and estimated transmission losses as required in section 95111(b). The electric power entity also must report whether transmission losses are made up in other imported electricity deliveries reported, or from California sources.

~~(2) For each generating unit operators shall include:~~

(5) *Imported Electricity from Asset-Controlling Suppliers.* The electric power entity must separately report imported electricity supplied by asset-controlling suppliers recognized by ARB. Each asset-controlling supplier must be identified on the NERC E-tags as the PSE at the first point of receipt. The electric power entity must:

~~(A) Generating unit ID designated by ARB, nameplate generating capacity (MW), and net power generated (MWh);~~

(A) Report the asset-controlling supplier standardized acronym or code, full name, and the ARB identification number;

(B) Report delivered electricity as specified and not as unspecified;

(C) Report delivered electricity from asset-controlling suppliers as measured at the first point of delivery in the state of California; and,

(D) Report GHG emissions calculated pursuant to section 95111(b).

~~(B) Fuel consumption by fuel type reporting in units of million standard cubic feet for gases, gallons for liquids, short tons for non-biomass solids, and bone dry short tons for biomass-derived solid fuels;~~

(6) *Imported Electricity from Multi-jurisdictional Retail Providers.* The electric power entity must separately report imported electricity supplied by multi-jurisdictional retail providers who are recognized by the ARB as asset-controlling suppliers. Multi-jurisdictional retail providers are recognized by the ARB as asset-controlling suppliers when their system power emission factor, calculated and published on the ARB Mandatory Reporting website, is greater than 1100 lbs CO_2e/MWh.

~~(C) CO_2, N_2O, and CH_4 emissions from fuel combustion in metric tonnes as specified in section 95111(c)-(d) by fuel type;~~

(A) The electric power entity must report imported electricity supplied by multi-jurisdictional retail providers as measured at the first point of delivery in California.

(B) Multi-jurisdictional retail providers must report retail sales in their California service territory as imported electricity.

(C) The electric power entity must report GHG emissions calculated pursuant to section 95111(b). For multi-jurisdictional retail providers recognized by ARB as an asset-controlling suppliers, refer to subsection 95111(b)(3) and 95111(b)(4).

~~(D) For units of facilities located inside California, wholesale sales (MWh) exported directly out-of-state by generating unit if applicable and as specified in section 95111(a)(1)(K).~~

(7) *Exported Electricity.* The electric power entity must report exported electricity in MWh and associated GHG emissions in MT of CO_2e aggregated by each final point of delivery outside the state of California, as well as the following information:

~~(3) ***Aggregation of Multiple Units.*** If a facility lacks the necessary metering or monitoring equipment to measure data individually for each generating unit, the operator may report data on an aggregated basis for multiple units that combust the same fuel type.~~

(A) For each final point of delivery outside the state of California, include the standardized acronym or code, full name, and the jurisdiction in which it is located.

(B) Exported electricity as measured at the last point of delivery located in the state of California, if known. If unknown, report as measured at the final point of delivery outside California.

(C) Do not report estimated transmission losses.

(D) Report zero MT of CO_2e for each final point of delivery published on the ARB Mandatory Reporting website as located in a linked jurisdiction.

(E) For other final points of delivery, report associated emissions for each point by multiplying MWh exported by the emission factor calculated and published on the ARB Mandatory Reporting website for unspecified imported electricity.

(8) *Exchange Agreements.* The electric power entity must report delivered electricity under power exchange agreements consistent with imported and exported electricity requirements of this section. Electricity delivered into the state of California under exchange agreements must be reported as imported electricity and electricity delivered out of California under exchange agreements must be reported as exported electricity.

(9) *Electricity Wheeled Through California.* The electric power entity must separately report electricity wheeled through California, aggregated by first

point of receipt outside California, and must exclude wheeled power transactions from reported imports and exports. When reporting electricity wheeled through California, the power entity must include the quantities of electricity wheeled through California as measured at the first point of delivery inside the state of California.

(10) *Verification Documentation.* The electric power entity must retain for purposes of verification NERC E-tags, written contracts, settlements data, and all other information needed to confirm reported electricity procurements and deliveries pursuant to the recordkeeping requirements of section 95105.

~~(4)~~ (11) *Electricity Generating Units and Cogeneration* ~~**Facilities.** Operators of generating facilities with~~*in California.* Electric power entities that also operate electricity generating units or cogeneration ~~systems subject to the~~located inside the state of California that meet the applicability requirements of this article ~~shall also meet the requirements of~~must report GHG emissions to ARB under section 95112.

(12) *Electricity Generating Units and Cogeneration Outside California.* Operators and owners of electricity generating units and cogeneration located outside the state of California who elect to report to ARB under section 95112 must fully comply with the reporting and verification requirements of this article.

(b) Calculating GHG Emissions.

(1) *Calculating GHG Emissions from Unspecified Sources.* For electricity from unspecified sources, the electric power entity must calculate the annual CO_2 equivalent mass emissions using the following equation:

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

Where:

CO_2e = Annual CO_2 equivalent mass emissions from the unspecified electricity deliveries at each point of receipt identified (metric tons).

MWh = Megawatt-hours of unspecified electricity deliveries at each point of receipt identified.

EF_{unsp} = Default emission factor for unspecified electricity imports calculated and published on the ARB Mandatory Reporting website .

EF_{unsp} = 0.435 MT of CO_2e/MWh for first points of receipt located in non-linked jurisdictions.

EF_{unsp} = 0 MT of CO_2e/MWh for points of receipt located in linked jurisdictions.

TL = Transmission loss correction factor.

TL = 1.02 when transmission losses are not made up in other electricity deliveries reported or from California sources.

TL = 1.0 when transmission losses are made up in other electricity deliveries reported or from California sources.

(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 (metric tons).

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. EF_{sp} = 0 MT of CO_2e for facilities located in linked jurisdictions and facilities, or units within facilities, below the GHG emissions compliance threshold for delivered electricity pursuant to the Cap-and-Trade Regulation

TL = Transmission loss correction factor.

TL = 1.02 when deliveries are not reported as measured at the busbar, and transmission losses are not made up in other electricity deliveries reported or from California sources.

TL = 1.0 when deliveries are reported as measured at the busbar, or transmission losses are made up in other electricity deliveries reported or from California sources.

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 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 from stationary combustion of fossil fuels, acid gas scrubbers, or acid gas reagents, as reported to ARB.

(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 equal to the sum of CO_2e emissions reported to U.S. EPA pursuant to 40 CFR Part 98.

(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.

$$E_{sp} = 0.001 \times \Sigma(Q_{fuel} \times EF_{fuel})$$

Where:

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

EF_{fuel} = CO_2e emission factor for the specified fuel type as required by this article (kg CO_2e /MMBtu).

(D) New facilities or units will be assigned an emission factor by the ARB based on the type of fuel combusted or the technology for the first year of reporting when a U.S. EPA GHG Report or EIA fuel consumption report is not available for the previous report year.

(3) *Calculating GHG Emissions of Imported Electricity from Specified Asset-Controlling Suppliers.* ARB will calculate and publish on the ARB Mandatory Reporting website system emission factors for the following asset-controlling suppliers: Bonneville Power Administration, multi-jurisdictional retail providers, and asset-controlling suppliers with a system emission factor greater than 1100 lbs CO_2e/MWh. For imported electricity from asset-controlling suppliers recognized by the ARB, the electric power entity must calculate emissions using the following equation:

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

Where:

CO_2e = Annual CO_2 equivalent mass emissions from the specified electricity deliveries from each supplier identified (metric tons).

MWh = Megawatt-hours of specified electricity deliveries.

EF_{ACS} = Supplier-specific emission factor published on the ARB Mandatory Reporting website (MT CO_2e/MWh). ARB will assign Bonneville Power Administration (BPA) a default system emission factor equal to 20 percent of the default emission factor for unspecified sources, or when available, based on a previously verified GHG report submitted to ARB, beginning in the 2010 data year and meeting the requirements for asset-controlling suppliers.

TL = Transmission loss correction factor.

TL = 1.02 when deliveries are not reported as measured at a first point of receipt located within the balancing authority area of the asset-controlling supplier and transmission losses are not made up in other electricity deliveries reported or from California sources.

TL = 1.0 when deliveries are reported as measured at a first point of receipt located within the balancing authority area of the asset-controlling supplier or transmission losses are made up in other electricity deliveries reported or from California sources.

The Executive Officer shall calculate the system emission factor for asset-controlling suppliers using the following equations:

EF_{ACS} = Sum of System Emissions MT of CO_2e / Sum of System MWh

$$\text{Sum of System Emissions, MT of } CO_2e = \Sigma E_{asp} + \Sigma(PE_{sp} * EF_{sp}) + \Sigma(PE_{unsp} * EF_{unsp}) - \Sigma(SE_{sp} * EF_{sp})$$

$$\text{Sum of System MWh} = \Sigma EG_{asp} + \Sigma PE_{sp} + \Sigma PE_{unsp} - \Sigma SE_{sp}$$

Where:

ΣE_{asp} = Sum of CO_2e emissions from each specified facility/unit in the asset-controlling supplier's fleet, consistent with section 95111(b)(2) (MT of CO_2e).

ΣEG_{asp} = Sum of net generation for each specified facility/unit in the asset-controlling supplier's fleet for the data year as reported to ARB under this article (MWh).

PE_{sp} = Amount of electricity purchased wholesale and taken from specified sources by the asset-controlling supplier for the data year as reported to ARB under this article (MWh).

PE_{unsp} = Amount of electricity purchased wholesale from unspecified sources by the asset-controlling supplier for the data year as reported to ARB under this article (MWh).

SE_{sp} = Amount of wholesale electricity sold from a specified source by the asset-controlling supplier for the data year as reported to ARB under this article (MWh).

EF_{sp} = CO_2e emission factor as defined for each specified facility or unit calculated consistent with section 95111(b)(2) (MT CO_2e/MWh).

EF_{unsp} = CO_2e default emission factor for unspecified sources calculated consistent with section 95111(b)(1) (MT CO_2e/MWh).

Multi-jurisdictional retail providers include emissions and megawatt-hours in the terms above from facilities or units that contribute to a common system power pool. Multi-jurisdictional retail providers do not include emissions or megawatt-hours in the terms above from facilities or units allocated to serve retail loads in designated states pursuant to a cost allocation methodology approved by the California Public Utilities

Commission (CPUC) and the utility regulatory commission of at least one additional state in which the multi-jurisdictional retail provider provides retail electric service.

(4) *Calculating GHG Emissions of Imported Electricity from Multi-jurisdictional Retail Providers.* Multi-jurisdictional retail providers must calculate emissions using the following equation:

$$CO_2e = \left(MWh_R - MWh_{WSP-CA} - EG_{CA}\right) \times TL \times EF_{MJRP} + MWh_{WSP-notCA} \times TL \times EF_{MJRP} - CO_2e_{linked}$$

Where:

CO_2e = Annual CO_2e mass emissions of imported electricity (metric tons).

MWh_R = Total electricity procured by multi-jurisdictional retail provider to serve its retail customers in California, reported as retail sales for California service territory, MWh.

MWh_{WSP-CA} = Wholesale electricity procured in California by multi-jurisdictional retail provider to serve its retail customers in California, as determined by the first point of receipt on a NERC E-tag and pursuant to a cost allocation methodology approved by the California Public Utilities Commission (CPUC) and the utility regulatory commission of at least one additional state in which the multi-jurisdictional retail provider provides retail electric service, MWh.

$MWh_{WSP-not\ CA}$ = Wholesale electricity imported into California by multi-jurisdictional retail provider with a final point of delivery in California and not used to serve its California retail customers, MWh.

EF_{MJRP} = Multi-jurisdictional retail provider system emission factor calculated by ARB pursuant to subsection 95111(b)(3) and consistent with a cost allocation methodology approved by the California Public Utilities Commission (CPUC) and the utility regulatory commission of at least one additional state in which the multi-jurisdictional retail provider provides retail electric service.

EG_{CA} = net generation measured at the busbar of facilities and units located in California that are allocated to serve its retail customers in California pursuant to a cost allocation methodology approved by the California Public Utilities Commission (CPUC) and the utility regulatory commission of at least one additional state in which the multi-jurisdictional retail provider provides retail electric service, MWh.

TL = Transmission loss correction factor.

TL = 1.02 when transmission losses are not made up in other electricity deliveries reported or from California sources.

TL = 1.0 when transmission losses are made up in other electricity deliveries reported or from California sources.

(c) *GHG Emissions Data Report: Additional Requirements for Retail Providers, excluding Multi-jurisdictional Retail Providers.* Retail providers must include the

following information in the GHG emissions data report for each report year, in addition to the information identified in section 95111(a)-(b).

(1) Retail providers that serve California load must report California retail sales.
(2) Retail providers may elect to report the subset of retail sales attributed to the electrification of shipping ports, truck stops, and motor vehicles if metering is available to separately track these sales from other retail sales.
(3) Retail providers that serve California load must claim as specified electricity all electricity imported from facilities or units in which they have an ownership share or written contract to procure electricity.
(4) For facilities or units that are fully or partially owned by a retail provider that have GHG emissions greater than the default emission factor for unspecified imported electricity based on the most recent GHG emissions data report submitted to ARB or U.S. EPA, the retail provider must include:

(A) The facility name, ARB facility identification number and generating unit identification number as applicable, percent ownership share at the facility level, ownership share at the generating unit level as applicable, both net and gross nameplate capacity, and both net and gross power generated in the report year;
(B) The quantity of electricity sold by the retail provider or on behalf of the retail provider from the facility or unit having a final point of delivery outside California, as measured at the busbar.

(5) Retail providers that report as electricity importers also must separately report electricity imported from specified and unspecified sources by other electric power entities to serve their load, designating the electricity importer.

(d) *GHG Emissions Data Report: Additional Requirements for Multi-Jurisdictional Retail Providers.* Multi-jurisdictional retail providers that provide electricity into California at the distribution level must include the following information in the GHG emissions data report for each report year, in addition to the information identified in section 95111(a)-(b).

(1) A report of the electricity transactions and GHG emissions associated with the common power system or contiguous service territory that includes consumers in California. This includes the requirements in this section as applicable for each generating facility or unit in the multi-jurisdictional retail provider's fleet;
(2) The multi-jurisdictional retail provider must include in its emissions data report wholesale power purchased and taken (MWh) from specified and unspecified sources and wholesale power sold from specified sources according to the specifications in this section, and as required for ARB to calculate a supplier-specific emission factor;
(3) Total retail sales (MWh) by the multi-jurisdictional retail provider in the contiguous service territory or power system that includes consumers in California;

(4) Retail sales (MWh) to California customers served in California's portion of the service territory;
(5) GHG emissions associated with the imported electricity, including both California retail sales and wholesale power imported into California from the retail provider's system, according to the specifications in this section;
(6) Multi-jurisdictional retail providers that serve California load must claim as specified power all power purchased or taken from facilities or units in which they have operational control or an ownership share or written contract;
(7) Multi-jurisdictional retail providers must provide the supplier-specific ARB identification number to electric power entities who purchase electricity from the supplier's system.

(e) *GHG Emissions Data Report:* Additional Requirements for WAPA and DWR.

~~(5) ***Out-of-State Facilities.*** Operators of out-of-state generating facilities that are not subject to any of the mandatory reporting requirements of this article may voluntarily submit a greenhouse gas emissions data report that meets applicable requirements in this article for generating facilities.~~
(1) In reporting its GHG emissions to ARB, the California Department of Water Resources shall include all applicable information identified in this article for retail providers, including the amount of electricity used for pump loads, to operate the State Water Project.
(2) In reporting its GHG emissions to ARB, the Western Area Power Agency shall include all applicable information identified in this article for retail providers, including the amount of electricity used for pump loads, to operate the Central Valley Project.

~~(6) ***Asset Owning/Asset***~~
(f) *GHG Emissions Data Report:* Additional Requirements for Asset-Controlling Suppliers. ~~An asset owning or asset controlling supplier may voluntarily~~Bonneville Power Administration may request that ~~ARB assign a supplier specific ID to the supplier's fleet of generating facilities if the supplier's sales of renewable energy account for 50 percent or more of their total sales of electric energy for the report year or if power purchased by the supplier from unspecified sources does not exceed 20 percent of the supplier's total sales of electric energy for the report year. An asset owning or asset~~ ARB calculate its supplier-specific emission factor based on a previously verified GHG report that meets the requirements for asset-controlling suppliers, instead of a default system emission factor equal to 20 percent of the default emission factor for unspecified sources. An asset-controlling supplier that chooses this option ~~shall~~must:

~~(A)~~ (1) Meet the requirements in this ~~article~~section as applicable for each generating facility or unit in the supplier's fleet;

~~(B) Include in its greenhouse gas emissions data report the list of the generating facilities in its fleet along with the ARB designated facility ID;~~

~~(C) If wholesale power purchased by the supplier accounts for more than 10 percent of total electric energy sold by the supplier for the report year, the supplier shall include in its greenhouse gas~~(2) Include in its emissions data report wholesale power purchased and taken (MWh) from specified and unspecified sources and wholesale power sold from specified sources according to the specifications in this section ~~95111(b)(1)(A)-(B)~~, and as required for ARB to calculate a supplier-specific emission factor;

~~(D)~~ (3) Retain for verification purposes documentation that the power sold by the supplier originated from the supplier's fleet of facilities and either that the fleet is under the supplier's ~~operation~~operational control or that the supplier serves as the fleet's exclusive marketer;

~~(E)~~ (4) Provide the supplier-specific ~~ID to retail providers~~ARB identification number to electric power entities who purchase ~~unspecified power~~electricity from the supplier's ~~fleet~~system.

~~(b) Retail Providers and Marketers.~~

~~(1) General Requirements for Retail Providers and Marketers. Retail providers and marketers shall meet the following general requirements in preparing their greenhouse gas emissions data report for each report year. Retail providers and marketers shall include electricity transactions associated with both renewable and nonrenewable energy sources of power.~~

~~(A) When reporting electricity transactions, retail providers and marketers shall:~~

~~1. Specify the amount of electricity in MWh;~~
~~2. For electricity from specified sources, specify the amount of electricity as measured at the busbar;~~
~~3. For electricity from unspecified sources, specify the amount of electricity as measured at the first point of receipt for which the reporting entity has information;~~
~~4. For electricity from specified sources, specify the facility name, the ARB designated facility ID, and the generating unit ID for the unit generating the power, if applicable;~~
~~5. Specify region of origin and region of destination;~~
~~6. Retail providers shall aggregate and specify electricity transactions by counterparty;~~
~~7. Marketers shall aggregate and specify electricity transactions by power supplier;~~
~~8. Specify the amount of electricity (MWh) that is null power when applicable;~~
~~9. Specify electricity received under exchange agreements as purchases and electricity delivered under exchange agreements as wholesale sales.~~

(B) If the region of origin for an electricity transaction cannot be documented, the retail provider or marketer shall designate the region as unknown.

(C) ***Power Wheeled Through California.*** When reporting power transactions involving imports into California or exports out of California, the retail provider or marketer shall exclude the amount of power imported into California that terminates in a location outside of California, as measured at the first California point of delivery.

(D) ***California Department of Water Resources (DWR).*** The California Department of Water Resources shall include all applicable information identified in this article for retail providers, including the amount of power used by DWR itself.

(E) ***Multi-jurisdictional Retail Providers.*** Multi-jurisdictional retail providers shall include information required for retail providers in this article for the service territory that includes California end-use customers.

(F) ***Western Area Power Administration (WAPA).*** The Western Area Power Administration shall include information required of retail providers in this article relating to serving end use California customers and reporting fugitive SF_6 emissions. In particular, WAPA shall include electricity transactions related to sources of electricity located in California that are used to serve WAPA's end-use California customers, power imported to California to serve WAPA's end-use customers including transactions from facilities owned by the Bureau of Reclamation on the Lower Colorado River, and power exported from California.

(2) ***Greenhouse Gas Emissions Data Report: Retail Providers and Marketers.*** Retail providers and marketers shall include the following information in the greenhouse gas emissions data report for each report year. Multi-jurisdictional retail providers shall include the information in sections 95111(b)(2)(A) and 95111(b)(2)(G)-(H) but are exempt from sections 95111(b)(2)(B)-(F).

(A) Fugitive emissions of SF_6 (kg) related to transmission and distribution systems, substations, and circuit breakers located inside California that the retail provider or marketer is responsible to maintain in proper working order. SF_6 emissions shall be calculated using the methodology specified in section 95111(f).

(B) Wholesale power imported (MWh) from specified sources with final point of delivery in California and for which the retail provider or marketer was the deliverer to the first point of delivery in California, designating the region of origin as PNW or SW.

(C) Wholesale power imported (MWh) from unspecified sources with final point of delivery in California and for which the retail provider or marketer was the deliverer to the first point of delivery in California. The retail provider or marketer shall designate the region of origin as PNW, SW, or unknown and shall retain for verification purposes NERC E-tags, settlements data, or other information as confirmation of the region of origin.

(D) Retail providers shall include wholesale power imported from specified and unspecified sources with final point of delivery in California for which the retail provider is not the deliverer to the first point of delivery in California, designating the region of origin. Transactions reported under this section 95111(b)(2)(D) shall not be duplicated under section 95111(b)(3)(F).

(E) Wholesale power exported (MWh) from specified sources located inside California, and designating the region of destination (PNW, SW, or unknown).

(F) Wholesale power exported (MWh) from unspecified sources located inside California, and designating the region of destination (PNW, SW, or unknown).

(G) ***Electricity Transactions Wheeled Through California***. Wholesale power imported (MWh) into California that terminates in a location outside of California, as measured at the first California point of delivery. The retail provider or marketer shall specify these transactions separately by the counterparty supplying power and specify the region of origin (PNW or SW). The retail provider or marketer shall retain for purposes of verification NERC E-tags, settlements data, or other information to confirm the transactions.

(H) Retail providers shall include in their greenhouse gas emissions data report for each report year the additional information listed in section 95111(b)(3).

(3) ***Greenhouse Gas Emissions Data Report: Additional Requirements for Retail Providers Only.*** Retail providers shall include the following information in the greenhouse gas emissions data report for each report year, in addition to the information identified in sections 95111(b)(1)-(2).

(A) The information listed in section 95111(a) for each generating facility over which the retail provider has operational control.

(B) The facility name, ARB designated facility ID, nameplate generating capacity (MW) and net power generated in the report year (MWh) for

~~generating facilities over which they have operational control that are powered by nuclear, hydroelectric, wind, or solar energy.~~

~~(C) Total retail sales in megawatt hours (MWh). Multi-jurisdictional retail providers shall include total retail sales for their service territories that include California customers and the portion of total annual retail sales to California customers only.~~

(g) *Requirements for Claims of Specified Sources of Imported Electricity and Associated Emissions.* Electricity importers must register specified sources and report associated GHG emissions as follows:

~~(D) Retail sales (MWh) from specified sources that use renewable energy may be reported as a subset of total retail sales in order to reflect special retail programs to reduce greenhouse gases. Retail providers that choose to report retail sales for these programs shall aggregate sales by specified facility and include the facility name, the ARB designated ID, and a description of the program.~~

(1) *Registration of Specified Sources and Suppliers.* Each electricity importer claiming specified sources or suppliers of electricity must register its specified sources and suppliers of electricity with ARB prior to January 1 of each reporting year. For purposes of registration under this paragraph, specified sources are facilities and units. Specified suppliers are asset-controlling suppliers and multi-jurisdictional retail providers. The electricity importer must include the following information when it registers its specified sources and suppliers:

~~(E) Wholesale power purchased or power taken (MWh) from in-state specified sources. For these transactions, the retail provider shall designate the region of origin as California.~~

(A) The facility names and, for specification to the unit level, provide the facility and unit names.

(B) For sources with a previously assigned ARB identification number, the ARB facility or unit identification number or supplier number published on ARB's mandatory reporting program website. For newly specified sources, ARB will assign a unique identification number.

(C) The facility and unit identification numbers as used for reporting to the Energy Information Administration, U.S. EPA Acid Rain Program, U.S. EPA pursuant to 40 CFR Part 98, and the California Energy Commission Eligible Renewable Resource identification number, as applicable.

(D) The physical address of each facility, including jurisdiction.

(E) The percent ownership share and whether the facility or unit is under the electricity importer's operational control.

(F) Total facility or unit gross and net nameplate capacity.

(G) Designate whether the facility emitted less than 25,000 metric tons of CO_2e as reported in the most recent GHG report to the ARB or to the U.S. EPA.

(H) Designate whether the facility or unit is a newly specified source, a continuing specified source, or was a specified source in the previous report year that will not be specified in the current report year.

(I) Provide the primary technology or fuel type as listed below:

1. Variable renewable resources by type, defined for purposes of this article as pure solar, pure wind, and run-of-river hydroelectricity;
2. Hybrid facilities such as solar thermal;
3. Hydroelectric facilities ≤ 30 MW, not run-of-river;
4. Hydroelectric > 30 MW;
5. Geothermal binary cycle plant or closed loop system;
6. Geothermal steam plant or open loop system;
7. Biomass-derived sources by primary fuel type;
8. Nuclear facilities;
9. Cogeneration by primary fuel type;
10. Fossil sources by primary fuel type;
11. Co-fired fuels;
12. Municipal solid waste combustion;
13. Other.

~~(F) Wholesale power purchased (MWh) from unspecified sources within California or from unknown sources. For these purchases the retail provider shall designate the region of origin as one of the following:~~

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

(3) *Owned Sources.* Electricity importers must report as specified sources of electricity the imported electricity from generating facilities or units located outside the state of California in which they have an ownership share, or written contract for a specified percentage of a facility's or unit's generation in the report year.

(4) *Delivery Tracking Conditions Required for Specified Electricity Imports.* Electricity importers may claim a specified source when the electricity delivery meets one of the following sets of conditions:

(A) The electricity importer has an ownership share in the facility or unit or a written contract for a specified percentage of the facility's or unit's generation in the report year;

(B) The electricity importer has a written contract to receive electricity generated by the facility or unit.

(5) *High GHG-Emitting Specified Facilities or Units.* For facilities or units that are operated by a retail provider or fully or partially owned by a retail provider, excluding multi-jurisdictional retail providers, and that have emissions greater than the default emission factor for unspecified electricity based on the most

recent GHG emissions data report submitted to ARB or to U.S.EPA, the retail provider must report the following information.

~~1. From the CAISO real-time market;~~
~~2. From the CAISO integrated forward market;~~
~~3. From California but other than from the CAISO markets.~~
~~4. From a region of origin that is unknown. Retail providers, other than multi-jurisdictional retail providers, shall report unspecified power purchased from an unknown region as an import under sections 95111(b)(2)(C) or section 95111(b)(2)(D), as applicable. Multi-jurisdictional retail providers shall include power purchased from an unknown region under section 95111(b)(3)(G).~~

(A) When the product of net generation (MWh) and ownership share is greater than imported electricity (MWh), emissions transferred outside California must be reported as

~~(G) Multi-jurisdictional retail providers shall include wholesale power purchased or power taken from specified sources and wholesale power purchased from unspecified sources not already reported under section 95111(b)(3)(E) or section 95111(b)(3)(F)1-3, designating the region of origin as PNW, SW, or unknown, as applicable.~~

$CO_2e = (EG_{sp}*OS - I_{sp})*EF_{sp.}$

Where:

EG_{sp} = facility or unit net generation, MWh.
OS = fraction ownership share.
I_{sp} = imported electricity, MWh.
$EF_{sp.}$ = facility or unit-specific emission factor, MT of CO_2e/MWh.

~~(H) Power purchased or taken (MWh) from a specified hydroelectric generating facility with nameplate capacity of > 30 MW (that is not a California eligible renewable resource) or from a specified nuclear facility shall be listed as one of the following:~~

(B) List the replacement generation sources, locations, and whether they are new units when I_{sp} < 90% of $EG_{sp}*OS$ and for a facility specified in the previous report year that has no imported electricity in the report year.

(6) *Low GHG-Emitting Existing, Fully Committed Resources: Nuclear and Large Hydroelectric Resources.* An emission factor of zero MT of CO_2e/MWh may only be used when electricity imported into California from a specified hydroelectric generating facility with nameplate capacity greater than 30 MW or a nuclear facility that was operational prior to January 1, 2010 meets one of the following conditions:

~~1. Power~~(A) Electricity purchased with a written contract in effect prior to January 1, ~~2008~~2010 that remains in effect or has been renegotiated for

the same facility for the same share or quantity of net generation within one year of contract expiration;

~~2. Power purchased not meeting the stipulation specified in section 95111(b)(3)(H)1. and that is not associated with an increase in the facility's generating capacity;~~

~~3. Power~~(B) Electricity purchased that does not ~~meeting the stipulation specified in section 95111(b)(3)(H)1.~~meet the first requirement that is associated with an increase in the facility's generating capacity due to increased efficiencies or other capacity increasing actions;

~~4. Power~~(C) Electricity purchased from hydroelectric generating facilities during a "spill or sell" situation where power not purchased is lost.;

~~5. Power~~(D) Electricity purchased that does not meet the ~~stipulation specified in section 95111(b)(3)(H)1.~~first requirement due to federal power redistribution policies for federally owned resources and not related to price bidding.

~~(I) ***Native Load.*** The retail provider may elect to designate the power taken from a generating facility partially or fully owned, or operated by the retail provider and power purchased or taken from other specified sources as serving native load if the facility meets one of the following criteria and shall state which of the criteria were met:~~

~~1. The generating facility is a California eligible renewable resource and, prior to the reporting date, the reporting entity has retired the WREGIS or NVTREC certificates associated with the power received from the facility during the report year.~~

~~2. The generating facility is a hydroelectric generation facility.~~

~~3. The generating facility is partially or fully owned by the retail provider, operated by the retail provider, or under a long term power contract. If a facility is designated as serving native load on this basis, all generating facilities from which the retail provider purchases or takes specified power that run at the same or greater average annual capacity factor shall also be designated as serving native load.~~

~~4. The generating facility is a qualifying facility whose generation the reporting entity purchases under a power contract.~~

~~(J) Retail providers shall designate a wholesale sale as inside California if the point of delivery of the sale is within California. If retail providers cannot provide documentation that the point of delivery of the sale is within California, then retail providers, not multi-jurisdictional, shall report the wholesale sale as an export under section 95111(b)(2)(E) or section 95111(b)(2)(F), as applicable, and multi-jurisdictional retail providers shall include the sale under section 95111(b)(3)(O).~~

~~(K) Wholesale sales (MWh) of power purchased or taken from specified facilities operated by the retail provider delivered to point of delivery inside~~

California and the designation of the region of destination as CAISO real-time market, CAISO integrated forward market, or California.

(L) Wholesale sales (MWh) of power purchased or taken from specified sources not operated by the retail provider delivered to point of delivery inside California and the designation of the region of destination as CAISO real-time market, CAISO integrated forward market, or California.

(M) Wholesale sales (MWh) of power purchased from unspecified sources delivered to counterparties inside California and the designation of the region of destination as CAISO real-time market, CAISO integrated forward market, or California.

(N) Multi-jurisdictional retail providers shall indicate those wholesale sales included in section 95111(b)(3)(K)-(M) for which they are the deliverer to the first point of delivery in California (not located within their own service territory.)

(O) Multi-jurisdictional retail providers shall include wholesale sales (MWh) of power purchased or taken from specified or unspecified sources not already reported in section 95111(b)(3)(K)-(N).

(P) If the retail provider holds a contract that entitles the retail provider to a specified percentage of a facility's generation in the report year, the retail provider shall include power purchased or sold from that facility as being from a partially owned facility.

(Q) For facilities fully or partially owned by the retail provider, include facility name, ARB designated facility ID, generating unit ID as applicable, percent ownership share at the facility level, ownership share at the generating unit level as applicable, and net power generated in the report year (MWh) if not already reported under section 95111(a).

(R) For facilities that are fully or partially owned by the retail provider and that have CO_2 emissions greater than 1,100 lbs of CO_2 per MWh based on the most recent greenhouse gas emissions data report that received a positive verification opinion or on CO_2 emissions reported to U.S.EPA under 40 CFR Part 75, the retail provider may elect to include:

1. Wholesale sales (MWh) made by the retail provider or on behalf of the retail provider from the facility or unit to counterparties located outside California where:
   i. The power could not be delivered to the reporting entity during the hours in which it was sold due to congestion in the transmission and distribution system or similar issues or;

ii. The retail provider did not need the power during the hours in which it was sold for reasons not related to reducing the retail provider's greenhouse gas emissions responsibility. Reasons may include, but are not limited to, the retail provider's own load was met by resources that were less expensive than the specified facility (excluding any value associated with greenhouse gas mitigation).

2. Amount of power generation that was reduced from the facility or unit in MWh per year as a result of the reduced demand for power by the retail provider. The retail provider shall retain documentation that associates reduced generation with reduced demand.

(S) The retail provider may elect to separately report retail sales related to the electrification of shipping ports, truck stops, and motor vehicles if metering is available to separately track these sales from other retail sales.

(c) ***Calculation of CO_2 Emissions from Stationary Combustion.*** Operators of generating facilities shall meet the following requirements in preparing CO_2 emission calculations from stationary combustion for inclusion in the greenhouse gas emissions data report.

(1) ***Natural Gas.*** Operators of generating facilities or units that combust natural gas and are subject to the requirements of 40 CFR Part 75 shall include Part 75 CO_2 emissions data for the report year. Operators may elect to use revenue fuel meters to conduct quality checks on generating unit level information. For facilities or units that combust natural gas but are not required to report CO_2 emissions under 40 CFR Part 75, the operator shall calculate and include CO_2 emissions using methodologies provided in:

(A) Sections 95125(c) (d) or (g) if the high heat value is $\geq$ 975 and $\leq$ 1100 Btu per scf or;

(B) Section 95125(d) or (g) if the high heat value is < 975 or > 1100 Btu per scf.

(2) ***Coal or Petroleum Coke.***

(A) Operators of generating facilities or units that combust coal or petroleum coke and are subject to the requirements of 40 CFR Part 75 shall include Part 75 CO_2 emissions data for the report year, or CO_2 emissions based on alternative equations and specifications by fuel type provided in 40 CFR Part 75, Appendix G;

(B) If the generating facility or unit is not subject to the requirements in 40 CFR Part 75, the operator of the generating facility shall calculate and

include CO_2 emissions using methods specified in section 95125(d) or section 95125(g).

(3) ***Middle Distillates, Gasoline, Residual Oil, or Liquid Petroleum Gases (LPG).***

(A) If a generating facility or unit combusts middle distillates (such as diesel, fuel oil, or kerosene), gasoline, residual oil, or LPG (such as ethane, propane, isobutene, n-Butane, or unspecified LPG) and is subject to the requirements of 40 CFR Part 75, the operator of the facility shall include Part 75 CO_2 emissions data for the report year;

(B) If the generating facility or unit is not subject to the requirements of 40 CFR Part 75, the operator shall calculate and include annual CO_2 emissions using the methods specified in sections 95125(c) (d) or (g).

(4) ***Refinery Fuel Gas, Flexigas, or Associated Gas.*** If a generating facility combusts refinery fuel gas, flexigas, or associated gas, the operator shall calculate and include CO_2 emissions for the report year using the methods specified by fuel type in sections 95113(a)(1)(A) (C) or 95113(a)(1)(E).

(5) ***Landfill Gas or Biogas.*** If a facility combusts landfill gas or biogas derived from biomass, the operator shall calculate and include CO_2 emissions for the report year using the method specified in section 95125(c), 95125(d), or 95125(g).

(6) ***Biomass Solids or Municipal Solid Waste.***

(A) If a facility combusts biomass solids or municipal solid waste, the operator shall calculate and include CO_2 emissions for the report year using methodologies provided in section 95125(g) based on continuous emission monitoring systems, CO_2 concentrations, and flue gas flow rates;

(B) If the facility combusts municipal solid waste and does not have appropriate devices to measure CO_2 concentrations and flue gas flow rates, the operator shall use methods specified in section 95125(h);

(C) If the facility combusts biomass solids and does not have appropriate devices to measure CO_2 concentrations and flue gas flow rates, the operator shall use a method specified in sections 95125 (c) (d) or (g) (h).

(7) ***CO_2 Emissions for Fuels Co-Fired.*** Operators shall use the following methodologies to determine separately and include CO_2 emissions from fuels (excluding refinery gases) that are co-fired at a facility.

(A) If more than one fossil fuel and only fossil fuels are co-fired in a facility that does not report using data from a continuous emissions monitoring system, then the operator shall calculate CO_2 emissions separately for each fuel type using methods provided in sections 95125(c)-(e) as specified by fuel type in sections 95111(c)(1)-(4). Operators who have the option in this article to calculate emissions based on data from a continuous emissions monitoring system, and who co-fire more than one fossil fuel, need not report emissions separately for each fossil fuel.

(B) If a biomass-derived fuel is co-fired with a fossil fuel in a facility and the operator does not report CO2 emissions using data from a continuous emissions monitoring system, then the operator shall calculate CO2 emissions separately for each fuel type using methods provided in sections 95125(a), (c), (d) or (e) as specified by fuel type in sections 95111(c)(1)-(6) and (8). If the facility does have a continuous emissions monitoring system, then the operator shall calculate emissions associated with each fuel using the methods specified in section 95125(g)(4).

(8) ***Start-Up Fuels.*** The operators of generating facilities that primarily combust biomass-derived fuels but that combust fossil fuels for start-up, shut-down, or malfunction operating periods only, shall calculate and include CO_2 emissions from fossil fuel combustion using the method provided in section 95125(a) or methods provided in sections 95125(c)-(e).

(d) ***Calculation of N_2O and CH_4 from Stationary Combustion.*** Operators of generating facilities shall use the methodologies provided in section 95125(b) to calculate and include N_2O and CH_4 emissions from stationary combustion.

(e) ***Calculation of CO_2 Process Emissions from Acid Gas Scrubbing.*** Operators that use acid gas scrubbers or add an acid gas reagent to the combustion source shall include CO_2 emissions from these processes if these emissions are not already captured in CO_2 emissions calculations based on a continuous emissions monitoring system. The operator shall calculate CO_2 emissions from the acid gas processes using the following equation:

$$CO_2 = S * R * (CO_{2\text{-}MW} / Sorbent_{MW})$$

Where:
CO_2 = CO_2 emitted from sorbent for the report year, metric tonnes;
S = Limestone or other sorbent used in the report year, metric tonnes;
R = Ratio of moles of CO_2 released upon capture of one mole of acid gas;
$CO_{2\text{-}MW}$ = molecular weight of carbon dioxide (44);
$Sorbent_{MW}$ = molecular weight of sorbent (if calcium carbonate, 100).

(f) ***Determining Fugitive SF_6 Emissions.*** Operators of generating facilities, retail providers, and marketers shall use the methodology provided by the U.S. EPA SF_6

Emission Reduction Partnership for Electric Power Systems to determine fugitive SF_6 emissions as specified in Appendix A. The operator shall convert pounds of SF_6 into kilograms.

(g) ***Determining Fugitive HFC Emissions.*** Operators of generating facilities shall calculate fugitive HFC emissions separately for each HFC compound used in cooling units that support power generation or are used in heat transfers to cool stack gases using the methodology provided by U.S. EPA SF_6 Emission Reduction Partnership but substituting HFCs for SF_6 in the methodology. The operator shall convert pounds of HFCs into kilograms. This section does not apply to air or water cooling systems or condensers that do not contain HFCs.

(1) Operators who are reporting by individual cooling unit may elect to use service logs to document HFC usage and emissions. Service logs should document all maintenance and service performed on the unit during the report year, including the quantity of HFCs added to or removed from the unit, and include a record at the beginning and end of each report year. The operator may use service log information along with the following simplified material balance equations to quantify fugitive HFCs from unit installation, servicing, and retirement, as applicable. The operator shall include the sum of HFC emissions from the applicable equations in the greenhouse gas emissions data report.

$$HFC_{Install} = R_{new} - C_{new}$$

$$HFC_{Service} = R_{recharge} - R_{recover}$$

$$HFC_{Retire} = C_{retire} - R_{retire}$$

Where:

$HFC_{Install}$ = HFC emitted during initial charging/installation of the unit, kilograms;

$HFC_{Service}$ = HFC emitted during use and servicing of the unit for the report year, kilograms;

HFC_{Retire} = HFC emitted during the removal from service/retirement of the unit, kilograms;

R_{new} = HFC used to fill new unit (omit if unit was pre-charged by the manufacturer), kilograms;

C_{new} = Nameplate capacity of new unit (omit if unit was pre-charged by the manufacturer), kilograms;

$R_{recharge}$ = HFC used to recharge the unit during maintenance and service, kilograms;

$R_{recover}$ = HFC recovered from the unit during maintenance and service, kilograms;

C_{retire} = Nameplate capacity of the retired unit, kilograms;

R_{retire} = HFC recovered from the retired unit, kilograms.

~~(h) **Calculation of Fugitive CH_4 Emissions.** Operators of generating facilities that combust coal shall calculate and include fugitive CH_4 emissions from coal storage using the methodology provided in section 95125(j).~~

If none of the conditions in (A) through (D) above are met, apply the default emission factor for unspecified electricity pursuant to section 95111(b).

~~(i) **Calculation of Fugitive CO_2 Emissions from Geothermal Generating Facilities.** Operators of geothermal electricity generating facilities shall calculate and include fugitive CO_2 emissions using one of the following methods:~~

~~(1) $CO_2 = EF * Heat * (0.001)$~~

~~Where~~

~~CO_2 = CO_2 emissions, metric tonnes per year;~~

~~EF = Default fugitive CO_2 emission factor for geothermal facilities as specified in Appendix A, kg per MMBtu;~~

~~Heat = Heat taken from geothermal steam and/or fluid, MMBtu per year.~~

~~(2) Operators of geothermal generating facilities may elect to calculate CO_2 emissions using ARB approved source specific emission factors derived from tests conducted at least annually under the supervision of ARB or the local air pollution control district or air quality management district. Upon approval of a test plan by ARB, the test procedures in that plan shall be repeated in future years to update the source specific emission factors annually. In the absence of source specific emission factors approved by ARB, the operator shall use the method specified above in section 95111(i)(1).~~

(7) *Substitute electricity.* Report substitute electricity received from specified and unspecified sources pursuant to the requirements of this section. Substitute electricity is provided under contract with specified facilities, not classified as variable renewable resources, to meet delivery requirements when the specified facility or unit is not operating.

NOTE: Authority cited: Sections 39600, 39601, 39607, 39607.4, 41511, 38510, and 38530, Health and Safety Code. Reference: Sections 39600, 41511, and 38530, Health and Safety Code.

§ 95112. ~~Data Requirements and Calculation Methods for Cogeneration Facilities~~Electricity Generation and Cogeneration Units.

The operator of a facility who is required to report under section 95101 of this article, and who is not eligible for abbreviated reporting under section 95103(a), must comply with Subparts C and D of 40 CFR Part 98 (§§98.30 to 98.48), as applicable, in reporting emissions from electricity generating and cogeneration units to ARB, except as otherwise provided in this section.

(a) ~~**Greenhouse Gas Emissions Data Report.** *The operator of a cogeneration facility specified in section 95101(b) shall include the following information in the greenhouse gas emissions data report for each report year. The operator of a*~~

~~*cogeneration facility that is a self-generation facility with nameplate generating capacity less than ten megawatts and is not otherwise subject to the requirements of this article as specified in Section 95101(b)(1)-(6) and (8), may elect to submit an abbreviated emissions data report as specified in Section 95112(c).*~~ *Basic Information for EGUs.* Notwithstanding any limitations in 40 CFR Parts 75 or 98, the operator of an electricity generating unit is required to include in the emissions data report the information listed in this paragraph. For aggregation of units that meet the applicable criteria in 40 CFR §98.36(c)(1)-(3), the operator may elect to report the following information for a group of aggregated units, in lieu of separately reporting for each single unit.

(1) ~~Facility level and generating unit information as specified in sections 95111(a)(1)-(3) as applicable.~~ Nameplate generating capacity in megawatts (MW);

(2) ~~Cogeneration System:~~
~~(A) Prime mover of each cogeneration system.~~
~~(B) Identification of the cogeneration facility as a topping cycle or bottoming cycle plant~~
~~(C) Description of waste heat technology, including nameplate data for waste heat boiler, waste heat jacket heat exchanger, absorption chiller, and hot water heat exchanger~~
Net and gross power generated, in megawatt hours (MWh);

(3) ~~Electricity Generation:~~
~~(A) Electricity sold wholesale (MWh)~~
~~(B) Electricity sold or provided directly to end-users (MWh) and end-user's NAICS code~~
~~(C) Electricity consumed on-site for each report year (MWh)~~
~~(D) Efficiency of electricity generation, if known~~
Fuel consumption by fuel type, reporting in units of million standard cubic feet for gases, gallons for liquids, short tons for non-biomass solids, and bone dry short tons for biomass-derived solids;

(4) ~~Thermal Energy Production:~~
~~(A) Total useful thermal output (MMBtu)~~
~~1. Amount of thermal energy sold or provided to cogeneration thermal host (MMBtu) and customer's NAICS code~~
~~2. Amount of thermal energy from the cogeneration system consumed on-site for processes other than the cogeneration system for each report year (MMBtu)~~
~~(B) Input steam to steam turbine, if measured (MMBtu)~~
~~(C) Output of heat recovery steam generator (MMBtu)~~
~~(D) Fuel fired for supplemental firing in the duct burner of the heat recovery steam generator (MMBtu)~~
~~(E) Efficiency of thermal energy production, if known~~
If not already required to be reported under 40 CFR §98.36(b)(6), annual CO_2, CH_4, and N_2O emissions from the unit, expressed in metric tons of each gas;

(5) ~~Distributed Emissions:~~

~~(A) Distributed emissions to thermal energy production (metric tonnes CO_2)~~
~~(B) Distributed emissions to electricity generation (metric tonnes CO_2)~~
~~(C) Distributed emissions to manufactured product outputs, as applicable (metric tonnes CO_2)~~

If used to calculate CO_2 emissions and not already required to be reported under 40 CFR §98.36(b)(6), weighted average carbon content and high heat value by fuel type, determined using the same procedures as specified for HHV in 40 CFR §98.32(a)(2)(ii).

(6) ~~Indirect electricity usage as specified in section 95125(k).~~ For facilities whose primary sector is not electricity generation, report the following electricity generation information at the facility level, if known:

(A) Electricity ~~purchased and consumed (kWh)~~ sold to the grid (MWh).
(B) Electricity ~~provider (Name)~~ sold or provided directly to end-users (MWh), end-user's NAICS code and ARB ID (if an ARB ID has been assigned).
(C) Electricity consumed on-site (MWh).

(b) ~~***Calculation of CO_2, N_2O, and CH_4 Emissions.*** Operators of cogeneration facilities shall calculate and report emissions for each source specified in this section.~~ Basic Information for Cogeneration Units. *In addition to the information required by paragraph (a) of this section, the operator of a cogeneration unit must:*

(1) ~~CO_2 emissions from stationary combustion using methodologies listed by fuel type for electricity generating facilities as specified in section 95111(c).~~ Indicate whether the unit is topping cycle or bottoming cycle plant, and the prime mover technology;

(2) ~~GHG emissions from processes and from fugitive sources as specified for electricity generating facilities in sections 95111(e)-(h), if applicable, using the methodologies designated in the respective sections.~~ Provide useful thermal output (mmBtu);

(3) ~~N_2O and CH_4 emissions from stationary combustion using the methodologies provided in section 95125(b).~~ Where steam or heat is acquired from another facility for the generation of electricity, report the provider, the provider's ARB ID, and the amount of acquired steam or heat (mmBtu);

(4) ~~**Distributed Emissions.** Topping cycle plant operators shall calculate distributed emissions for electricity generation and thermal energy production separately using the Efficiency Method provided in section 95112(b)(4)(A). Bottoming cycle plant operators shall calculate distributed emissions for electricity generation, thermal energy production, and manufactured product outputs using the Detailed Efficiency Method provided in section 95112(b)(4)(B).~~

(A) Distributed Emissions for Topping Cycle Plants: Operators shall calculate distributed emissions using the Efficiency Method equations specified in this section, 95112(b)(4)(A). Operators shall distribute emissions to electricity generation by subtracting distributed emissions to thermal energy production from emissions from stationary combustion for the report year. Operators shall calculate emissions using a facility-specific electricity generation efficiency value as specified in section 95112(b)(4)(A)1, if parameters are known. Operators shall use the Heat Recovery Steam Generator (HRSG) or boiler manufacturer's rating for the thermal energy production efficiency value, if known. Operators may use assumed values of 0.35 for electricity generation efficiency and/or 0.80 for thermal energy production efficiency, when parameters are unknown.

Efficiency Method

Thermal Energy Production *Electricity Generation*

Where:

E_H = Distributed emissions to thermal energy production, metric tonnes CO_2

H = Total useful thermal output for the report year, MMBtu

e_H = Efficiency of thermal energy production

P = Power generated for the report year, MMBtu
(MWh x 3.413) = MMBtu

e_P = Efficiency of electricity generation

E_T = CO_2 emissions from stationary combustion in the report year, metric tonnes CO_2

E_P = Distributed emissions to electricity generation, metric tonnes CO_2

1. *Facility-Specific Electricity Generation Efficiency Value:*

e_P =

Where:

e_P = Efficiency of electricity generation

P = Power generated for the report year, MMBtu

F = Total fuel input, MMBtu

(B) Distributed Emissions for Bottoming Cycle Plants: Operators shall calculate distributed emissions using the Detailed Efficiency Method equations specified in this section, 95112(b)(4)(B). Operators shall distribute emissions to electricity generation by subtracting distributed emissions to thermal energy production and manufactured product from stationary combustion emissions for the report year. Bottoming cycle plant operators shall calculate stationary combustion emissions for the

~~manufacturing process as specified in section 95112(b)(4)(B)2. Operators shall report emissions using a calculated facility-specific electricity generation efficiency value as specified in section 95112(b)(4)(B)1, if parameters are known. Operators shall use the Heat Recovery Steam Generator (HRSG) or boiler manufacturer's rating for the thermal energy production efficiency value, if known. Operators may use assumed values of 0.35 for electricity generation efficiency and/or 0.80 for thermal energy production efficiency, when parameters are unknown.~~

~~*Detailed Efficiency Method*~~

~~*Thermal Energy Production — Electricity Generation*~~

~~Where:~~

~~E_H = Distributed emissions to thermal energy production, metric tonnes CO_2~~
~~H = Total useful thermal output for the report year, MMBtu~~
~~e_H = Efficiency of thermal energy production~~
~~P = Power generated for the report year, MMBtu (MWh * 3.413) = MMBtu~~
~~e_P = Efficiency of electricity generation~~
~~E_T = CO_2 emissions from stationary combustion in the report year, metric tonnes~~
~~E_M = Distributed emissions to manufacturing product, metric tonnes CO_2, computed as specified in section 95112(b)(4)(B)2.~~
~~E_P = Distributed emissions to electricity generation, metric tonnes CO_2~~

~~1. *Facility-Specific Electricity Generation Efficiency Value:*~~

~~e_P =~~

~~Where:~~

~~e_P = Efficiency of electricity generation~~
~~P = Power generated for the report year, MMBtu~~
~~H_{ST} = Input steam to steam turbine, MMBtu.~~

~~2. *Emissions Assigned to Manufacturing Process:*~~

~~Where:~~

~~E_M = Distributed emissions to manufacturing product, metric tonnes CO_2~~
~~E_T = Emissions from stationary combustion in the report year, metric tonnes CO_2~~
~~P = Power generated for the report year, MMBtu~~

~~(MWh * 3.413) = MMBtu~~

~~H = Total useful thermal output for the report year, MMBtu~~

~~F = Total fuel input, MMBtu~~

~~F_S = Fuel fired for supplemental firing in the duct burner of the HRSG, MMBtu~~

~~H_e = Exothermic heat from manufacturing process, MMBtu, computed as specified in section 95112(b)(4)(B)3.~~

~~e_H = Efficiency of thermal energy production~~

~~H_e shall only be included if an exothermic manufacturing process is used.~~

~~3. *Exothermic Heat from Manufacturing Process*~~

~~Where:~~

~~H_e = Exothermic heat from manufacturing process, MMBtu~~

~~HRSG = Output of heat recovery steam generator in the report year, MMBtu~~

~~e_H = Efficiency of thermal energy production~~

~~F = Total fuel input, MMBtu~~

~~If H_e value calculated above is negative, then the exothermic heat of the process is not sufficient to overcome the process use and/or loss of the input fuel heat, and the H_e value is set to 0.~~

Where supplemental firing has been applied to support electricity generation or industrial output, report fuel consumption by fuel type using the units in paragraph (a)(3) of this section and indicate the purpose of the supplemental firing.

(c) ~~***Abbreviated Greenhouse Gas Emissions Data Report.*** The operator of a cogeneration facility that is a self-generation facility with nameplate generating capacity <10 MW and is not otherwise subject to the requirements of this article as specified in Section 95101(b)(1)-(6) and (8), and who elects to submit an abbreviated emissions data report, shall include the following information for each report year.~~ CO_2 from Fossil Fuel Combustion. *When calculating CO_2 emissions from fuel combustion, the operator who is subject to Subpart C or D of 40 CFR Part 98 must use a method in 40 CFR §98.33(a)(1) to §98.33(a)(4) as specified by fuel type in section 95115 of this article.*

~~(1) At the facility level, operators shall include:~~

~~(A) ARB designated facility identification number (ID), nameplate generating capacity in megawatts (MW), and net power generated in the report year in megawatt hours (MWh);~~
~~(B) Total fuel consumption by fuel type for each cogeneration system reporting in units of million standard cubic feet for gases, gallons for liquids, short tons for non-biomass solids, and bone dry short tons for biomass-derived solid fuels;~~
~~(C) Cogeneration system information as specified in section 95112 (a)(2);~~
~~(D) Electricity generation information as specified in section 95112 (a)(3);~~
~~(E) CO_2, N_2O, and CH_4 emissions from stationary combustion associated with the facility's cogeneration system in metric tonnes, calculated as specified in section 95112(d);~~
~~1. CO_2 emissions from biomass-derived fuels (metric tonnes)~~

~~(2) For each generating unit operators shall include:~~

~~(A) Generating unit ID designated by ARB, nameplate generating capacity (MW), and net power generated (MWh);~~
~~(B) Fuel consumption by fuel type, where generating units of the same fuel type are separately metered;~~
~~(C) CO_2, N_2O, and CH_4 emissions from fuel combustion in metric tonnes as specified in section 95112(d), where generating units of the same fuel type are separately metered.~~

~~(3) Operators may elect to submit any of the additional information required in section 95112(a).~~

(d) ~~***Calculation of CO_2, N_2O, and CH_4 Emissions.*** The operator of a cogeneration facility that files an abbreviated emissions data report as specified in section 95112(c) shall calculate emissions for each source specified in this section:~~ *Monitoring, Data and Records.* For each emissions calculation method chosen under section 95112(c), the operator must meet the applicable requirements for monitoring, missing data procedures, data reporting, and records retention that are specified in 40 CFR §98.34 to §98.37, except as modified in sections 95112, 95115, and 95129 of this article.

~~(1) CO_2 emissions from stationary combustion using the methodologies provided in either (A), (B), or (C) below.~~

~~(A) Use of continuous emissions monitoring systems (CEMS) as specified in section 95125(g);~~
~~(B) Use of default emission factors as specified in section 95125(a);~~
~~(C) Use of fuel heat content, carbon content or other fuel-specific parameters as specified in section 95125(c), (d), or (h).~~

~~(2) N_2O and CH_4 emissions from stationary combustion using the methodologies provided in section 95125(b).~~

(e) *Biomass Emissions for Units Reporting Under 40 CFR Part 75.* Operators of electricity generating and cogeneration units subject to 40 CFR Part 75 and the data reporting requirements in 40 CFR §98.36(d) that combust both fossil and biomass-derived fuels must separately report CO_2 emissions from combustion of fossil fuels and CO_2 emissions from the combustion of biomass-derived fuels. The biogenic portion of CO_2 emissions must be calculated according to the methodology specified in 40 CFR §98.33(e).

(f) *CO_2 and CH_4 Emissions from Geothermal Facilities.* Operators of geothermal generating facilities must calculate annual emissions of CO_2 and CH_4 from geothermal energy sources using source specific emission factors derived from a measurement plan approved by the ARB. The operator must submit to the Executive Officer a measurement plan at least 45 days prior to the first test date. The measurement plan must include testing at least annually, and more frequently as needed. Upon approval of the measurement plan by the Executive Officer, the test procedures in that plan must be performed as specified in the plan. The Executive Officer and the local air pollution control officer must be notified at least 20 days in advance of subsequent tests.

(g) *Hydrogen Fuel Cells.* Operators of stationary hydrogen fuel cell units that produce hydrogen on-site must report information on the feedstocks used in hydrogen production. The operator must include the following information in the annual GHG emissions data report:

(1) Nameplate generating capacity in megawatts (MW);
(2) Net and gross power generated, in megawatt hours (MWh);
(3) Fuel or feedstock consumption by fuel/feedstock type, reporting in units of million standard cubic feet for gases, gallons for liquids, short tons for non-biomass solids, and bone dry short tons for biomass-derived solids;
(4) The provider of each fuel or feedstock, and the user's customer account number;
(5) Cogeneration information in section 95112(b), if applicable.

(h) *Missing Data Substitution Procedures.* To substitute for missing data for emissions reported under sections 95112 or 95115 of this article (stationary combustion units and units using continuous emissions monitoring systems), the operator must follow the requirements of section 95129 of this article. Facilities reporting under 40 CFR Part 75 must substitute for missing data under the requirements of that part, as specified in 40 CFR §98.45.

NOTE: Authority cited: Sections 39600, 39601, 39607, 39607.4, 41511, 38510, and 38530, Health and Safety Code. Reference: Sections 39600, 41511, and 38530, Health and Safety Code.

§ 95113. ~~Data Requirements and Calculation Methods for~~ Petroleum Refineries.

The operator of a facility who is required to report under section 95101 of this article, and who is not eligible for abbreviated reporting under section 95103(a), must comply with Subpart Y of 40 CFR Part 98 (40 CFR §§98.250 to 98.258) in reporting annual emissions from petroleum refineries to ARB, except as otherwise provided in this section.

(a) ~~**Greenhouse Gas Emissions Data Report.** The operator of a petroleum refinery specified in section 95101(b) shall include in the emissions data report for each report year the information required by this section, using the calculation methods specified.~~ *CO_2 from Fossil Fuel Combustion.* When calculating CO_2 emissions from fuel combustion under subpart C as specified at 40 CFR §98.252(a), the operator must use a method in 40 CFR §98.33(a)(1) to §98.33(a)(4) as specified by fuel type in section 95115 of this article. CO_2 emissions from refinery fuel gas combustion must be calculated using a Tier 3 or Tier 4 methodology of subpart C, as specified in 40 CFR §98.252(a).

~~(1) ***Stationary Combustion – CO_2 Emissions.***~~
~~The operator may elect to determine CO_2 combustion emissions using Continuous Emissions Monitoring Systems (CEMS) as specified in section 95125(g) (metric tonnes). In the absence of such CEMS data the operator shall use the following methods by fuel type.~~

~~(A) Refinery Fuel Gas: CO_2 emissions resulting from the combustion of refinery fuel gas as specified in section 95125(d) or 95125(e), (metric tonnes).~~

~~(B) Natural Gas and Associated Gas: CO_2 emissions resulting from the combustion of natural gas and associated gas as specified in section 95125(c) or 95125(d), (metric tonnes).~~

~~(C) Fuel Mixtures: CO_2 emissions resulting from the combustion of each fuel contained in the fuel mixture or for each fuel mixture as specified in section 95125(f), (metric tonnes).~~

~~(D) Other Fuels: CO_2 emissions resulting from the combustion of No. 1, No. 2, No 4, No. 5, and No. 6 fuels, kerosene, residual oil, distillate oil, gasoline, diesel fuel, and LPG using the methods specified in section 95125(a), 95125(c), or 95125(d), (metric tonnes).~~

~~(E) Low Btu gases: CO_2 emissions resulting from the combustion and/or destruction of low Btu gases as specified in section 95125(f) or 95113(d)(3). CO_2 emissions resulting from the combustion of flexigas as specified in section 95125(d)(3)(A), (metric tonnes).~~

~~(2) ***Stationary Combustion – CH_4 and N_2O.*** Emissions from stationary combustion sources using methods specified in section 95125(b), (metric tonnes).~~

~~(3) ***Fuel and Feedstock Consumption.*** Fuel consumption and feedstock consumption used to calculate GHG emissions by type in the report year (including petroleum coke) reporting in units of million standard cubic feet for gases, gallons for liquids, short tons for non-biomass solids, and bone dry short tons for biomass-derived solid fuels.~~

~~(4) ***Hydrogen Production Plant Emissions.*** The operator shall calculate emissions using the methodologies specified in section 95114, (metric tonnes).~~

~~(5) ***Process Emissions.*** The operator shall calculate process emissions using the methodologies in section 95113(b), (metric tonnes), and shall report any CO_2 molecular fractions derived from approved source tests as specified in section 95113(b)(5)(B).~~

~~(6) ***Fugitive Emissions.*** The operator shall calculate fugitive emissions using the methods specified in section 95113(c), (metric tonnes).~~

~~(7) ***Flaring Emissions.*** The operator shall calculate flare and control device emissions using the methods specified in section 95113(d), (metric tonnes)~~

~~(8) ***Electricity Generating Units.*** Operators of refineries with electricity generating units subject to the requirements of this article shall meet the requirements of section 95111.~~

~~*(9)* ***Cogeneration Emissions.*** Operators of refineries with cogeneration systems subject to the requirements of this article shall meet the requirements of section 95112.~~

~~(10) ***Indirect Energy Purchases.*** The operator shall calculate indirect energy purchased and consumed using methods specified in section 95125(k)-(l).~~

(b) ~~***Calculation of Process Emissions.*** The operator shall calculate process emissions as specified in this section. Operators may elect to calculate CO_2 process emissions resulting from catalyst regeneration (sections 95113(b)(1) and 95113(b)(2)) using a continuous emission monitoring system as specified in section 95125(g). In the absence of such CEMS data the operator shall use the following methods.~~ *Monitoring, Data and Records.* For each emissions calculation method

chosen under section 95113(a), the operator must meet the applicable requirements for monitoring, missing data procedures, data reporting, and records retention that are specified in 40 CFR §98.34 to §98.37, except as modified in sections 95113(l), 95115, and 95129 of this article.

~~(1) Catalytic Cracking~~

~~(A) The operator shall calculate and report CO_2 emissions from the continuous regeneration of catalyst material in fluid catalytic cracking units (FCCU) and fluid cokers using the methods specified in sections 95113(b)(1). Hourly coke burn rate shall be calculated as shown below:~~

~~$CR = K_1Q_r(\%CO_2 + \%CO) + K_2Q_a - K_3Q_r[\%CO/2 + \%CO_2 + \%O_2] + K_3Q_{oxy}(\%O_{xy})$~~

~~Where:~~

~~CR = hourly coke burn rate (kg/hr or lb/hr)~~

~~K_1, K_2, K_3 = material balance and conversion factors (K_1, K_2, and K_3 see Table 11, Appendix A)~~

~~Q_r = volumetric flow rate of exhaust gas before entering the emission control system (dscm/min or dscf/min)~~

~~Q_a = volumetric flow rate of air to regenerator as determined from control room instrumentation (dscm/min or dscf/min)~~

~~$\%CO_2$ = percent CO_2 concentration in regenerator exhaust, percent by volume – dry basis~~

~~%CO = percent CO concentration in regenerator exhaust, percent by volume – dry basis~~

~~$\%O_2$ = percent oxygen concentration in regenerator exhaust, percent by volume – dry basis~~

~~Q_{oxy} = volumetric flow rate of O_2 enriched air to regenerator as determined from control room instrumentation (dscm/min or dscf/min)~~

~~$\%O_{xy}$ = O_2 concentration in O_2 enriched air stream inlet to regenerator, percent by volume – dry basis~~

~~Q_r shall be determined in the following manner:~~

~~$Q_r = (79 * Q_a + (100 - \%O_{xy}) * Q_{oxy})/(100 - \%CO_2 - \%CO - \%O_2)$~~

~~Where:~~

~~Q_r = volumetric flow rate of exhaust gas from regenerator before entering the emission control system (dscm/min or dscf/min)~~

~~Q_a = volumetric flow rate of air to regenerator, as determined from control room instrumentation (dscm/min or dscf/min)~~

~~$\%Q_{xy}$ = oxygen concentration in oxygen enriched air stream, percent by volume – dry basis~~

~~Q_{oxy} = volumetric flow rate of O_2 enriched air to regenerator as determined from catalytic cracking unit control room instrumentation (dscm/min or dscf/min)~~

$\%CO_2$ = carbon dioxide concentration in regenerator exhaust, percent by volume – dry basis
%CO = carbon monoxide concentration in regenerator exhaust, percent by volume – dry basis. When no auxiliary fuel is burned and a continuous CO monitor is not required, assume %CO to be zero
$\%O_2$ = O_2 concentration in regenerator exhaust, percent by volume – dry basis

(B) The operator shall calculate a daily average coke burn rate (CR_d) for each day of operation as the sum of hourly coke burn rate determinations for each hour of operation divided by the number of operational hours per day. CR_d (lb/day) shall be converted to (kg/day).

(C) The operator shall calculate and report CO_2 emissions as shown below:

$$CO_2 = \sum_{1}^{n} CR_d * CF * 3.664 * 0.001$$

Where:

CO_2 = CO_2 emissions (metric tonnes/yr)
n = number of days of operation in the report year
CR_d = daily average coke burn rate (kg/day)
CF = carbon fraction in coke burned
3.664 = conversion factor – carbon to carbon dioxide
0.001 = conversion factor – kg to metric tonnes

(2) Other Catalyst Regeneration

(A) The operator shall calculate and report process CO_2 emissions resulting from periodic catalyst regeneration as shown below.

$$CO_2 = \sum_{1}^{n} CRR * (CF_{spent} - CF_{regen}) * 3.664 * 0.001$$

Where:

CO_2 = CO_2 emissions (metric tonnes/yr)
CRR = mass of catalyst regenerated (mass/regeneration cycle)
CF_{spent} = weight fraction carbon on spent catalyst
CF_{regen} = weight fraction carbon on regenerated catalyst (default = 0)
n = number of regeneration cycles
3.664 = conversion factor – carbon to carbon dioxide
0.001 = conversion factor – kg to metric tonnes

(B) The operator shall calculate and report process CO_2 emissions resulting from continuous catalyst regeneration in operations other than FCCU and fluid cokers (e.g. catalytic reforming) as shown below.

$$CO_2 = CC_{irc} * (CF_{spent} - CF_{regen}) * H * 3.664$$

Where:

CO_2 = CO_2 emissions (metric tonnes/yr)

CC_{irc} = average catalyst regeneration rate (tonnes/hr)

CF_{spent} = weight carbon fraction on spent catalyst

CF_{regen} = weight carbon fraction on regenerated catalyst (default = 0)

H = hours regenerator was operational (hr/yr)

3.664 = conversion factor – carbon to carbon dioxide

(3) Process Vents

(A) The operator shall calculate and report process emissions of CO_2, CH_4, and N_2O from process vents using the method shown below. Process emissions calculated and reported using other methods specified in this regulation shall not be calculated and reported here.

$$E_x = \sum_{1}^{n} VR * F_x * MW_x/MVC * VT * 0.001$$

Where:

E_x = emissions of x (metric tonnes/yr)

(x = CO_2, N_2O, CH_4)

VR = vent rate (scf/unit time)

F_x = molar fraction of x in vent gas stream

MW_x = molecular weight of x (kg/kg-mole)

MVC = molar volume conversion (849.5 scf/kg-mole for STP of 20°C and 1 atmosphere or 836 scf/kg-mole for STP of 60°F, and 1 atmosphere)

VT = time duration of venting

n = number of venting events

0.001 = conversion factor – kg to metric tonnes

(4) Asphalt Production

(A) The operator shall calculate and report CO_2 and CH_4 emissions resulting from asphalt blowing activities (where these emissions are not reported to the local AQMD/APCD and subsequently reported as directed in section 95113(d)) using the method specified below:

$$CH_4 = (M_A * EF * MW_{CH4}/MVC)(1 - DE) * 0.001$$

Where:

CH_4 = CH_4 emissions (metric tonnes/yr)

M_A = mass of asphalt blown (10^3 bbl/yr)

EF = emission factor (EF = 2,555 scf CH_4/10^3 bbl)

MW_{CH4} = CH_4 molecular weight (16.04 kg/kg-mole)

MVC = molar volume conversion factor (849.5 scf/kg- mole, for STP of 20°C and 1 atmosphere)

DE = control measure destruction efficiency (DE = 98% expressed as 0.98)

0.001 = conversion factor – kg to metric tonnes

$$CO_2 = (M_A * EF * MW_{CH4}/MVC) * DE * 2.743 * 0.001$$

Where:

CO_2 = CO_2 emissions (metric tonnes/yr)

M_A = mass of asphalt blown (10^3 bbl/yr)

EF = emission factor (EF = 2,555 scf CH_4/10^3 bbl)

MW_{CH4} = CH_4 molecular weight (16.04 kg/kg-mole)

MVC = molar volume conversion factor (849.5 scf/kg mole, for STP of 20°C and 1 atmosphere)

DE = control measure destruction efficiency (DE = 98% expressed as 0.98)

2.743 = CH_4 to CO_2 conversion factor

0.001 = conversion factor – kg to metric tonnes

(5) Sulfur Recovery

(A) The Operator shall calculate and report CO_2 process emissions from sulfur recovery units (SRU) using the methods specified below:

$$CO_2 = FR * MW_{CO2}/MVC * MF * 0.001$$

Where:

CO_2 = emissions of CO_2 (metric tonnes/yr)

FR = volumetric flow rate of acid gas to SRU (scf/year)

MW_{CO2} = molecular weight of CO_2 (44 kg/kg-mole)

MVC = molar volume conversion (849.5 scf/ kg-mole, for STP of 20°C and 1 atmosphere or 836 scf/kg-mole, for STP of 60°F, and 1 atmosphere)

MF = molecular fraction (%) of CO_2 in sour gas (default MF = 20% expressed as 0.20)

0.001 = conversion factor – kg to metric tonnes

(B) As an alternative to using the default MF value, the operator may elect to calculate CO_2 emissions using an ARB approved, source specific

~~molecular fraction of CO_2 in the sour gas, derived from source tests conducted at least once per calendar year under the supervision of ARB or the local air pollution control district or air quality management district. Upon approval of a source test plan by ARB, the source test procedures in that plan shall be repeated in subsequent years to update the source specific CO_2 molecular fractions annually. In the absence of source specific CO_2 molecular fractions approved by ARB, the operator shall use the default value provided in section 95113(b)(5)(A).~~

(c) ~~**Calculation of Fugitive Emissions.** The operator shall calculate and report fugitive emissions as specified below.~~ *Refinery Fuel Gas Sampling.* As required by 40 CFR §98.34(b)(3)(ii)(E), in cases where equipment necessary to perform daily sampling and analysis of carbon content and molecular weight for refinery fuel gas is not in place, such equipment must be installed and procedures established to implement daily sampling and analysis no later than January 1, 2013.

~~(1) Wastewater Treatment – CH_4 and N_2O~~

~~(A) The operator shall calculate and report methane emissions from wastewater treatment as shown below:~~

~~$$CH_4 = [(Q * COD_{qave}) - S] * B * MCF * 0.001$$~~

~~Where:~~

~~CH_4 = emission of methane (tonnes/yr)~~
~~Q = volume of wastewater treated (m^3/yr)~~
~~COD_{qave} = average of quarterly determinations of chemical oxygen demand of the wastewater (kg/m^3)~~
~~S = organic component removed as sludge (kg COD/yr)~~
~~B = methane generation capacity (B = 0.25 kg CH_4/kg COD)~~
~~MCF = methane conversion factor for anaerobic decay (0-1.0) consult Table 12 in Appendix A~~
~~0.001 = conversion factor – kg to metric tonnes~~

~~(B) The operator shall calculate and report nitrous oxide emissions from wastewater treatment as shown below:~~

~~$$N_2O = Q * N_{qave} * EF_{N2O} * 1.571 * 0.001$$~~

~~Where:~~

~~N_2O = emissions of N_2O (metric tonnes/yr)~~
~~Q = volume of wastewater treated (m^3/yr)~~
~~N_{qave} = average of quarterly determinations of N in effluent (kg N/m^3)~~
~~EF_{N2O} = emission factor for N_2O from discharged wastewater (0.005 kg N_2O-N/kg N)~~

~~1.571 = conversion factor – kg N_2O-N to kg N_2O~~
~~0.001 = conversion factor – kg to metric tonnes~~

~~(2) Oil-Water Separators – The operator shall calculate and report emissions from oil-water separators as shown below.~~

~~$CH_4 = EF_{sep} * V_{water} * CF_{NMHC} * 0.001$~~

~~Where:~~
~~CH_4 = emission of methane (tonnes/yr)~~
~~EF_{sep} = NMHC (non methane hydrocarbon) emission factor (kg/m^3) see Table 13 in Appendix A.~~
~~V_{water} = volume of waste water treated by the separator (m^3/yr)~~
~~CF_{NMHC} = NMHC to CH_4 conversion factor (CF_{NMHC} = 0.6)~~
~~0.001 = conversion factor – kg to metric tonnes~~

~~(3) Storage Tanks~~

~~(A) The operator shall calculate and report CH_4 emissions from crude oil, naphtha, distillate oil, asphalt, and gas oil storage tanks using the U.S. EPA TANKS Model (Version 4.09D). VOC emission values generated by the model shall be converted to methane emissions using a default conversion factor of 0.6 (CH_4 = 0.6 * VOC). Alternatively, operators may determine species-specific conversion factors determined by storage tank headspace vapor analysis using ARB approved sampling and analysis methodology.~~

~~(4) Equipment Fugitive Emissions~~

~~(A) The operator shall calculate and report CH_4 fugitive emissions for all gas service components as specified in CAPCOA (1999) Method 3: Correlation Equation Method in the following manner:~~

~~1. Components shall be identified as one of the following classification types: valve, pump seal, other, connector, flange, open-ended line. Operators shall use the Component Identification and Counting Methodology and screening methods found in CAPCOA (1999), which is incorporated by reference herein.~~

~~2. Screening values (SV) for each component comprising all natural gas, refinery fuel gas, and PSA off-gas systems shall be measured and recorded using instrumentation capable of detecting methane. Operators shall conduct screenings at the frequency interval required by their local air district.~~

~~3. Operators shall calculate VOC emissions in the following manner:~~

a. Zero Components – Use of Default Zero Factor. For zero components (components where the SV, corrected for background, equals 0.0 ppmv – i.e., the SV is indistinguishable from zero) for each screening period (e.g. month, quarter, year), operators shall calculate VOC emissions as follows:

$$E_{VOC\,0} = \sum_{i=1}^{6} CC_i * ZF_{i0} * t$$

Where:

$E_{VOC\,0}$ = zero component VOC emission (kg/screening period)

i = component type (1 = valve, 2 = pump seal, 3 = other, 4 = connector, 5 = flange, 6 = open-ended line)

CC_i = number of i components where SV = 0

ZF_{i0} = zero VOC emission factor (kg/hr) for component i (see Appendix A, Table 14)

t = time (hours) since last screening

b. Leaking Components – Use of Correlation Equation. Operators shall choose one of the following emission calculation pathways for leaking components based on local air district rules applicable at the facility.

For facilities located in air districts which authorize the use of correlation equations for screening values between background and 9,999 ppmv, the operator shall use the following method for these components and the pegged component method found in section 95113(c)(4)(A)(3)(c) for components pegged over 9,999 ppmv.

For facilities located in air districts which authorize the use of correlation equations for screening values between background and 99,999 ppmv, the operator shall use the following method for these components and the pegged component method found in section 95113(c)(4)(A)(3)(d) for components pegged over 99,999 ppmv.

$$E_{VOCL\,C} = \sum_{i=1}^{6} \sum_{n=1}^{n} (\sigma_i * SV_n^{\beta i}) * t$$

Where:

$E_{VOCL\,C}$ = leaking components VOC emissions (kg/screening period)

~~i = component type (1=valve, 2=pump seal, 3=others, 4=connector, 5=flange, 6=open-ended line)~~
~~n = number of i components~~
~~σ_i = correlation equation coefficient for component type i (see Appendix A, Table 14)~~
~~SV_n = screening value for component n~~
~~βi = correlation equation exponent for component type i (see Appendix A, Table 14)~~
~~t = time (hours) component has been leaking -- default value is time from last screening~~

~~c. Pegged components over SV 9,999 ppmv. The operator shall calculate VOC emissions for each screening period (e.g. month, quarter, year) as follows:~~

$$E_{VOCP\text{-}10} = \sum_{i=1}^{6} CC_i * PF_{iP\text{-}10} * t$$

~~Where:~~
~~$E_{VOCP\text{-}10}$ = VOC emissions for components pegged over SV 9,999 ppmv (kg/screening period)~~
~~i = component type (1=valve, 2=pump seal, 3=others, 4=connector, 5=flange, 6=open-ended line)~~
~~CC_i = number of i components pegged over 9,999 ppmv~~
~~$PF_{iP\text{-}10}$ = VOC emission factor (kg/hr) for component type i pegged over 9,999 ppmv (see Appendix A, Table 14)~~
~~t = time component has been leaking (hours) -- default value is time since last screening~~

~~d. Pegged components over 99,999 ppmv. The operator shall calculate VOC emissions for each screening period (e.g. month, quarter, year) as follows:~~

$$E_{VOCP\text{-}100} = \sum_{i=1}^{6} CC_i * PF_{iP\text{-}100} * t$$

~~Where:~~
~~$E_{VOCP\text{-}100}$ = VOC emissions for components pegged over 99,999 ppmv (kg/screening period)~~
~~i = component type (1=valve, 2=pump seal, 3=others, 4=connector, 5=flange, 6=open-ended line)~~
~~CC_i = number of i components pegged over 99,999 ppmv~~
~~$PF_{iP\text{-}100}$ = VOC emission factor (kg/hr) for component type i pegged over 99,999 ppmv (see Appendix A, Table 14)~~
~~t = time component has been leaking (hours) -- default value~~

~~is time since last screening~~

~~4. The operator shall calculate and report methane emissions in the following manner:~~

$$CH_4 = \sum_{1}^{n} (E_{VOC\text{-}0} + E_{VOC\text{-}LC} + [E_{VOCP\text{-}10} \text{ or } E_{VOCP\text{-}100}]) * CF_{VOC} * 0.001$$

~~Where:~~

~~CH_4 = methane emissions (metric tonnes/year)~~

~~n = number of screenings/year~~

~~$E_{VOC\text{-}0}$ = zero component VOC emissions (kg/screening period)~~

~~$E_{VOC\text{-}LC}$ = leaking component VOC emissions (kg/screening period)~~

~~$E_{VOCP\text{-}10}$ = VOC emissions for components pegged over 9,999 ppmv (kg/screening period)~~

~~$E_{VOCP\text{-}100}$ = VOC emissions for components pegged over 99,999 ppmv (kg/screening period)~~

~~CF_{VOC} = VOC to CH_4 conversion factor (default CF_{VOC}=0.6)~~

~~0.001 = conversion factor – kg to metric tonnes~~

~~The operator shall include the term $E_{VOCP\text{-}10}$ if the local air district authorizes the use of correlation equations for screening values between background and 9,999 ppmv. Operators shall include the term $E_{VOCP\text{-}100}$ if the local air district authorizes the use of correlation equations for screening values between background and 99,999 ppmv.~~

~~Where available, operators shall use system specific determinations of gas composition and methane content (refinery fuel gas, natural gas, associated gas, flexigas, low Btu gas) to determine a CF_{VOC} value. When representative data is not available, operators shall use the default value (CF_{VOC} = 0.6) provided by ARB.~~

(d) ~~**Calculation of Emissions from Flares and Other Control Devices.**~~ *Calculating CO_2 from Flares.* For periods of normal flare operation, the operator must use Equation Y-1 or Equation Y-2 as specified in 40 CFR §98.253(b)(ii)(A) or 98.253(b)(ii)(B). For periods of startup, shutdown, and malfunction (SSM) during which the operator was unable to measure the parameters required by Equations Y-1 and Y-2, the operator must determine the quantity of gas discharged to the flare separately for each SSM, and calculate the CO_2 emissions as specified in the equation shown below. For SSM periods the operator must use engineering calculations and process knowledge to estimate the carbon content of flared gas as required by §98.253(b)(iii)(A). The terms of the equation below are defined as they are for Equation Y-3 in 40 CFR §98.253(b)(iii)(C).

$$CO_2 = 0.98 \times 0.001 \times \left(\sum_{p=1}^{n} \left[44/12 \times (Flare_{SSM})_p \right] \times MW_p / MVC \times CC_p \right)$$

~~(1) The operator shall calculate and report CO_2, CH_4 and N_2O emissions resulting from the combustion of flare pilot and purge gas using the appropriate method(s) specified in sections 95113(a)(1) and (2).~~

~~(2) The operator shall calculate and report CO_2 (and CH_4 where applicable) emissions resulting from the combustion of hydrocarbons routed to flares for destruction using one of the methods specified below:~~

~~(A) Operators required to report CH_4 and NMHC emissions to a local Air Quality Management District or Air Pollution Control District shall calculate CO_2 emissions as follows:~~

$$CO_2 = \sum_{1}^{365} [CF_{NMHC} * NMHC * FE/(100-FE) * 3.664 + CH_4 * FE/(100-FE) * 2.743] * 0.001$$

~~Where:~~

~~CO_2 = emissions of CO_2 (metric tonnes/yr)~~
~~CF_{NMHC} = carbon fraction in NMHC (CF_{NMHC} = 0.6)~~
~~NMHC = flare non-methane hydrocarbon emissions (kg/day)~~
~~CH_4 = flare methane emissions (kg/day)~~
~~FE = flare destruction efficiency (%)~~
~~3.664 = conversion factor – carbon to carbon dioxide~~
~~2.743 = conversion factor – methane to carbon dioxide~~
~~0.001 = conversion factor – kg to metric tonnes~~

~~When sampling to determine the actual value of CF_{NMHC} is mandated by the AQMD/APCD, the operator shall use the measured value in lieu of 0.6.~~

~~The operator shall use flare destruction efficiencies (FE) specified by the local APCD/AQMD.~~

~~The operator shall also report the sum of all flare CH_4 emissions reported to the local AQMD/APCD for the report year (metric tonnes/yr).~~

~~(B) The operator who is subject to Rule 1118, Control of Emissions from Refinery Flares (South Coast Air Quality Management District), shall calculate ROG as specified in Attachment B of Rule 1118 and report flare CO_2 emissions as follows:~~

$$CO_2 = \sum_{1}^{365} (CF_{ROG} * [ROG * FE/(100-FE)] * 3.664) * 0.001$$

~~Where:~~

~~CO_2 = emissions of CO_2 (metric tonnes/yr)~~
~~CF_{ROG} = carbon fraction in ROG (CF_{ROG} = 0.6)~~
~~ROG = reactive organic gas flare emissions (kg/day)~~
~~FE = flare destruction efficiency (%)~~
~~3.664 = conversion factor – carbon to carbon dioxide~~
~~0.001 = conversion factor – kg to metric tonnes~~

~~The operator shall use flare destruction efficiencies (FE) specified by the local AQMD/APCD.~~

~~(C) The operator who is not required to report flare emissions to a local AQMD/APCD shall calculate CO_2 emissions as shown below:~~

$$CO_2 = RFT * EF_{NMHC} * CF_{NMHC} * 3.664 * 0.001$$

~~Where:~~

~~CO_2 = CO_2 emissions (metric tonnes/year)~~
~~RFT = refinery feed through-put (m^3/yr)~~
~~EF_{NMHC} = non-methane hydrocarbon emission factor (EF_{NMHC} = 0.002 kg/m^3 through-put)~~
~~CF_{NMHC} = conversion factor – NMHC to carbon (CF_{NMHC} = 0.6)~~
~~3.664 = conversion factor – carbon to carbon dioxide~~
~~0.001 = conversion factor – kg to metric tonnes~~

~~(3) The operator who utilizes other methods for the destruction of low Btu gases (e.g. coker flue gas, gases from vapor recovery systems, casing vents and product storage tanks) such as incineration or combustion as a supplemental fuel in heaters, boilers etc., shall calculate and report CO_2 emissions as specified below:~~

$$CO_2 = GV_A * CC_A * MW_A * 1/MVC * 3.664 * 0.001$$

~~Where:~~

~~CO_2 = CO_2 emissions (metric tonnes/year)~~
~~GV_A = volume of gas A destroyed annually (scf/year)~~
~~CC_A = carbon content of gas A (kg C/kg fuel)~~
~~MW_A = molecular weight of gas A~~
~~MVC = molar volume conversion factor (849.5 scf/kg-mole for STP of 20°C and 1 atmosphere or 836 scf/kg-mole, for STP of 60°F, and 1 atmosphere)~~
~~3.664 = conversion factor – carbon to carbon dioxide~~
~~0.001 = conversion factor – kg to metric tonnes~~

~~The operator shall determine CC_A and MW_A quarterly (four times per year) using methods specified in section 95125(d)(3)(A) and compute an annual average value. GV_A shall be determined to~~

~~assure accuracy within ± 7.5%.~~

(e) *Calculating CO_2 from FCCUs and Fluid Coking.* The requirements of 40 CFR §98.253(c)(2) apply under this article regardless of the rated capacity of a fluid catalytic cracking unit or a fluid coking unit. The operator may not use Equation Y-8 or the option provided under 40 CFR §98.253(c)(3) for units with rated capacities of 10,000 barrels per stream day or less.

(f) *Calculating CH_4 from Delayed Coking Units.* When calculating CH_4 emissions from the depressurization of the coking unit vessel as required by 40 CFR §98.253(i), the operator must conduct the sampling and engineering analysis necessary to apply the two terms below, from Equation Y-18, modified as follows:

f_{void} = Volumetric void fraction of coking vessel prior to steaming based on engineering calculations (cf gas/cf of vessel).

MF_{CH4} = Average mole fraction of methane in coking vessel gas based on the analysis of at least two samples per year, collected at least four months apart (kg-mole CH_4/kg-mole gas, wet basis).

(g) *Uncontrolled Blowdown Systems.* When calculating CH_4 emissions for uncontrolled blowdown systems as required by 40 CFR §98.253(k), the operator must use the methods for process vents in 40 CFR §98.253(j).

(h) *Data Reporting Requirements for Flares.* When the operator has calculated flare emissions for SSM periods using the modified equation specified in section 95113(d), the operator reporting data under the requirements of 40 CFR §98.256(e)(8) must report only the total number of SSM events, the volume of gas flared, and the average molecular weight and carbon content of the flare gas for each SSM event, using the units specified.

(i) *Data Reporting Requirements for FCCUs and Coking Units.* When the operator has calculated CO_2 from fluid catalytic cracking units or fluid coking units consistent with section 95113(e), the operator shall not report the data required by 40 CFR §98.256(f)(9).

(j) *Data Reporting Requirements for Uncontrolled Blowdown Systems.* When the operator has calculated CH_4 from uncontrolled blowdown systems consistent with section 95113(g), the operator must report the information required for process vents in 40 CFR §98.256(l), as applicable, in lieu of the information required by 40 CFR §98.256(m)(2).

(k) *Records that must be retained.* In addition to the requirements of 40 CFR §98.257, for each process vent for which the concentration of CO_2, N_2O and CH_4 are determined to be below the thresholds in 40 CFR §98.253(j), the operator must maintain records of the method used to determine the CO_2, N_2O, and CH_4 concentrations, and all supporting documentation necessary to demonstrate that the

thresholds in 40 CFR §98.253(j) are not exceeded during the data year pursuant to the record keeping requirements of section 95105.

(l) *Missing Data Substitution Procedures.* The operator must comply with 40 CFR §98.255 when substituting for missing data, except as otherwise provided in paragraphs (1)-(2) below.

(1) To substitute for missing data for emissions reported under section 95115 of this article (stationary combustion units and units using continuous emissions monitoring systems), the operator must follow the requirements of section 95129 of this article.

(2) For all other data required for emissions calculations in this section, the operator must follow the requirements of paragraphs (A)-(B) below.

(A) If the analytical data capture rate is at least 90 percent for the data year, the operator must substitute each missing value using the best available estimate of the parameter, based on all available process data.

(B) If the analytical data capture rate is at least 80 percent but not at least 90 percent for the data year, the operator must substitute each missing value with the highest quality assured value recorded for the parameter during the given data year, as well as the two previous data years.

(C) If the analytical data capture rate is less than 80 percent for the data year, the operator must substitute each missing value with the highest quality assured value recorded for the parameter in all records kept according to section 95105(a).

(m) *Additional Data Reporting Requirements for Benchmarking Purposes.* The operator must report production quantities for the data year of each petroleum product listed in Table C-1 of 40 CFR Part 98, and each additional transportation fuel product listed in Table MM-1 of 40 CFR Part 98 (standard cubic feet for gaseous products, gallons for liquid products, short tons for solid products).

NOTE: Authority cited: Sections 39600, 39601, 39607, 39607.4, 41511, 38510, and 38530, Health and Safety Code. Reference: Sections 39600, 41511, and 38530, Health and Safety Code.

§ 95114. ~~Data Requirements and Calculation Methods for~~ Hydrogen Plants.

The operator of a facility who is required to report under section 95101 of this article, and who is not eligible for abbreviated reporting under section 95103(a), must comply with Subpart P of 40 CFR Part 98 (40 CFR §§98.160 to 98.168) in reporting annual emissions from hydrogen production to ARB, except as otherwise provided in this section.

(a) ~~***Greenhouse Gas Emissions Data Report.*** The operator of a hydrogen production facility specified in section 95101(b), shall include in the emissions~~

~~data report for each report year the information required by this section, using the calculation methods specified.~~ *Definition of Source Category.* This source category includes merchant hydrogen production facilities located within another facility if they are not owned by, or under the direct control of, the other facility's owner or operator.

~~(1) ***Fuel and Feedstock Consumption.*** Fuel consumption and feedstock consumption in the report year by fuel/feedstock type (including petroleum coke) reporting in units of million standard cubic feet for gases, gallons for liquids, short tons for non-biomass solids, and bone dry short tons for biomass-derived solid fuels.~~

~~(2) ***Production.*** The operator shall report the total hydrogen produced at the facility in the report year (scf) and the amount of hydrogen sold for use as transportation fuel (scf).~~

~~(3) ***Stationary Combustion – CH_4 and N_2O.*** The operator shall calculate and report CH_4 and N_2O emissions from stationary combustion sources using methods specified in section 95125(b), (metric tonnes).~~

~~(4) ***Fugitive Emissions.*** The operator shall calculate and report fugitive emissions using the methods specified in section 95113(c), (metric tonnes).~~

~~(5) ***Flaring Emissions.*** The operator shall calculate and report emissions from flares and control devices (if these emissions are not calculated using other methods specified in this regulation) using the methods specified in section 95113(d), (metric tonnes).~~

~~(6) ***Transferred CO_2 and CO.*** The operator shall calculate and report the amount of CO_2 and CO sold as transferred carbon dioxide and carbon monoxide respectively, (metric tonnes). Transferred carbon dioxide and carbon monoxide shall not be subtracted from total CO_2 emissions reported.~~

~~(7) ***Process Vent Emissions.*** The operator shall report process vent emissions not reported using other methods specified in this regulation as specified in section 95113(b)(3), (metric tonnes)~~

~~(8) ***Sulfur Recovery Process Emissions.*** The operator shall report CO_2 process emissions from sulfur recovery units as specified in section 95113(b)(5), (metric tonnes).~~

~~(9) ***Electricity Generating Units.*** The operators of hydrogen plants with electricity generating units subject to the requirements of this article shall meet the requirements of section 95111.~~

~~(10) **Cogeneration Emissions.** The operators of hydrogen plants with cogeneration systems subject to the requirements of this article shall meet the requirements of section 95112.~~

~~(11) **Indirect Energy Purchases.** The operator shall report all indirect energy purchased and consumed as specified in sections 95125(k)-(l).~~

~~(12) **Stationary Combustion and Process CO_2 Emissions.** The operator shall calculate and report stationary combustion and process CO_2 emissions as specified in section 95114(b), (metric tonnes).~~

(b) ~~**Calculation of CO_2 Stationary Combustion and Process Emissions.** The operator shall calculate and report CO_2 stationary combustion and process emissions using one of the methods specified in this section.~~ *CO_2 from Fossil Fuel Combustion.* When calculating CO_2 emissions from fuel combustion under subpart C as specified at 40 CFR §98.162(b)-(c), the operator must use a method in 40 CFR §98.33(a)(1) to §98.33(a)(4) as specified by fuel type in section 95115 of this article.

~~(1) **Continuous Emission Monitoring Systems.** The operator may elect to calculate CO_2 process and stationary combustion using Continuous Emissions Monitoring Systems (CEMS) as specified in section 95125(g)(7).~~

~~(2) **Fuel and Feedstock Mass Balance.** The operator may elect to calculate CO_2 process and stationary combustion emissions using the method specified below.~~

$$CO_2(\text{Fuel}) = \sum_{1}^{n} \sum_{1}^{x} (F_a * CF_a) * 3.664 * 0.001$$

$$CO_2(\text{Feedstock}) = \sum_{1}^{n} \sum_{1}^{y} [(FS_b * CF_b) - S] * 3.664 * 0.001$$

$$CO_2(\text{Mass Balance}) = CO_2(\text{Fuel}) + CO_2(\text{Feedstock})$$

~~Where:~~

~~$CO_2(\ )$ = carbon dioxide (fuel) (feedstock) and (mass balance) emissions (metric tonnes/year)~~
~~n = days of operation per reporting period~~
~~F_a = fuel a consumption rate (scf or gallon/day)~~
~~x = total number of fuels~~
~~CF_a = carbon content of fuel a (kg C/scf or gallon fuel)~~
~~FS_b = feedstock b consumption rate (scf/day)~~
~~CF_b = carbon content of feedstock b (kg C/scf feedstock)~~
~~y = total number of feedstocks~~

S = carbon accounted for elsewhere (kg C/day)
3.664 = conversion factor—carbon to carbon dioxide
0.001 = conversion factor—kg to metric tonnes

The operator shall limit the application and use of factor S to situations where CO_2 and/or CH_4 emissions are accounted for using other methods specified in these regulations (for example: uncoverted carbon contained in PSA off-gas or hydrogen plant product that is diverted to fuel gas systems, fed to downstream units and recovered as fuel gas or hydrogen plant feed or diverted to flare where emissions are calculated and reported using applicable methods specified in this regulation). The operator shall determine the carbon content of all feedstock mixtures daily. The operator shall determine the carbon content of natural gas that is not mixed with another fuel or feedstock prior to consumption once per month. The operator shall choose sampling locations in a manner that minimizes bias.

(3) ***Fuel Stationary Combustion and Feedstock Process Emissions.*** The operator may elect to calculate CO_2 process and stationary combustion emissions using the methods specified below.

(A) The operator shall calculate CO_2 stationary combustion emissions using methods specified in section 95113(a)(1)

(B) The operator shall calculate CO_2 process emissions using the method specified in this section.

$$CO_2 = \sum_{1}^{n} \sum_{1}^{x} [(FSR_i * CF_i) - S] * 3.664 * 0.001$$

Where:

CO_2 = carbon dioxide emissions (metric tonnes/yr)
n = number of operational days
x = number of feedstocks
FSR_i = feedstock i supply rate (scf/day)
CF_i = carbon content of feedstock i (kg C/scf feedstock)
S = carbon accounted for elsewhere (kg C/day)
3.664 = conversion factor—carbon to carbon dioxide
0.001 = conversion factor—kg to metric tonnes

The operator shall limit the application and use of factor S to situations where CO_2 and/or CH_4 emissions are accounted for using other methods specified in these regulations (for example: unconverted carbon contained in PSA off-gas or hydrogen plant product that is diverted to fuel gas systems, fed to downstream units and recovered as fuel gas or hydrogen plant feed or diverted to flare where emissions are calculated and reported using applicable methods specified in this regulation). The operator shall

~~determine the carbon content of all feedstock mixtures daily. The operator shall determine the carbon content of natural gas that is not mixed with another fuel or feedstock prior to consumption once per month. The operator shall choose sampling locations in a manner that minimizes bias.~~

(c) *Monitoring, Data and Records.* For each emissions calculation method chosen under section 95114(b), the operator must meet the applicable requirements for monitoring, missing data procedures, data reporting, and records retention that are specified in 40 CFR §98.34 to §98.37, except as modified in sections 95114(h), 95115, and 95129 of this article.

(d) *CO_2 Process Emissions.* When calculating CO_2 under the fuel and feedstock material balance approach specified at 40 CFR §98.163(b), the operator must apply the weighted average carbon content values obtained (the term CC_n in Equations P-1 through P-3) according to the frequencies specified in section 95114(e).

(e) *Sampling Frequencies.* When monitoring GHG emissions without a CEMS as specified at 40 CFR §98.164(b)(2), and reporting data as specified at §98.166, the operator must determine the carbon content and molecular weight values for fuels and feedstocks according to the frequencies specified below.

(1) When reporting CO_2 emissions for gaseous fuel and feedstock as specified in 40 CFR §98.163(b)(1), the operator must use a weighted average carbon content from the results of one or more analyses for month n for natural gas, or from daily analysis for gaseous fuels and feedstocks other than natural gas;
(2) When reporting CO_2 emissions for liquid fuel and feedstock as specified in 40 CFR §98.163(b)(2), the operator must use weighted average carbon content from the results of daily sampling for month n. Daily liquid samples may be combined to generate a monthly composite sample for carbon analysis;
(3) When reporting CO_2 emissions for solid fuel and feedstock as specified in 40 CFR §98.163(b)(3), the operator must use weighted average carbon content from the results of daily sampling for month n. Daily solid samples may be combined to generate a monthly composite sample for carbon analysis.

(f) *Weighted Average Sampling.* Where this section requires sampling of a parameter on a more frequent basis than 40 CFR Part 98, the operator or supplier must comply with the following:

(1) The samples must be spaced apart as evenly as possible over time, taking into account the operating schedule of the relevant unit or facility.
(2) The operator or supplier must calculate and report a weighted average of the values derived from the samples by using the following formula:

$$V_E = \frac{\sum_{j=1}^{n}(V_j \times M_j)}{\sum_{j=1}^{n} M_j}$$

Where:

V_E = The value of the parameter to be reported under 40 C.F.R. Part 98 for period E.

j = Each period during period E for which a sample is required by this article.

n = The number of periods j in period E.

V_j = The value of the sample for period j.

M_j = The mass of the sampled material processed or otherwise used by the relevant unit or facility in period j.

(3) The operator or supplier must keep records of the date and result for each sample or composite sample and mass measurement used in the equation above and of the calculation of each weighted average included in the emissions data report, pursuant to the record keeping requirements of section 95105.

(g) *Data Reporting Requirements.* When reporting data as specified at §98.166, the operator must also report the amount of carbon in unconverted feedstock for which GHG emissions are calculated and reported by the facility using other calculation methods provided in this regulation. For example, carbon in waste diverted to a fuel system or flare, where the CO_2 and CH_4 emissions are calculated and reported using other methods provided in this regulation, should be separately specified (metric tons of CO_2e/year). The operator must also report the amount of hydrogen produced and sold as a transportation fuel, if known.

(h) *Missing Data Substitution Procedures.* The operator must comply with 40 CFR §98.165 when substituting for missing data, except as otherwise provided in paragraphs (1)-(2) below.

(1) To substitute for missing data for emissions reported under section 95115 of this article (stationary combustion units and units using continuous emissions monitoring systems), the operator must follow the requirements of section 95129 of this article.

(2) For all other data required for emissions calculations in this section, the operator must follow the requirements of paragraphs (A)-(C) below.

(A) If the analytical data capture rate is at least 90 percent for the data year, the operator must substitute each missing value using the best available estimate of the parameter, based on all available process data.

(B) If the analytical data capture rate is at least 80 percent but not at least 90

percent for the data year, the operator must substitute each missing value with the highest quality assured value recorded for the parameter during the given data year, as well as the two previous data years.

(C) If the analytical data capture rate is less than 80 percent for the data year, the operator must substitute each missing value with the highest quality assured value recorded for the parameter in all records kept according to section 95105(a).

NOTE: Authority cited: Sections 39600, 39601, 39607, 39607.4, 41511, 38510, and 38530, Health and Safety Code. Reference: Sections 39600, 41511, and 38530, Health and Safety Code.

§ 95115. ~~Data Requirements and Calculation Methods for General~~ Stationary Fuel Combustion ~~Facilities~~Sources.

The operator of a facility who is required to report under section 95101 of this article, and who is not eligible for abbreviated reporting under section 95103(a), must comply with Subpart C of 40 CFR Part 98 (§§98.30 to 98.38) in reporting annual stationary fuel combustion emissions to ARB, except as otherwise provided in this section.

(a) ~~***Emissions data report.*** The operator of any facility specified in section 95101(b)(8) that emits greater than or equal to 25,000 metric tonnes per year of CO_2 from stationary combustion sources shall submit an emissions data report for each report year. The operator shall include the following information in the emissions data report:~~ *CO_2 from Steam Producing Units.* The operator of a steam producing unit combusting municipal solid waste or solid biomass fuels may use Equation C-2c of 40 CFR §98.33(a)(2)(B)(iii). Operators of units combusting fossil-based solid fuels must select applicable Tier 3 or Tier 4 methods.

~~(1) Stationary combustion emissions:~~

~~(A) Total CO_2 emissions (metric tonnes)~~

~~1. CO_2 emissions from biomass-derived fuels (metric tonnes)~~

~~(B) Total CH_4 emissions (metric tonnes)~~

~~(C) Total N_2O emissions (metric tonnes)~~

~~(2) Fuels information:~~

~~(A) Fuel consumption by fuel type, reporting in units of million standard cubic feet for gases, gallons for liquids, short tons for non-biomass solids, and bone dry short tons for biomass-derived solid fuels. The operator shall determine and provide consumption of each fuel by direct measurement for the report year. If there are no installed devices for direct measurement of fuel consumption, facilities shall determine consumption on the basis of recorded fuel purchase or sales invoices measuring any stock change (measured in million Btu, gallons, million standard cubic feet, short tons or bone dry short ,tons) using the following equation:~~

~~*Fuel Consumption in the Report Year = Total Fuel Purchases – Total Fuel Sales + Amount Stored at Beginning of Year – Amount Stored at Year End*~~

~~For reporting, Btu fuel consumption values shall be converted to million standard cubic feet, gallons, short tons, or bone dry short tons, using heat content values provided by the supplier, measured by the facility, or using values provided in Table 4 of Appendix A.~~

~~(B) Average annual carbon content as a percent by fuel type, if measured or provided by fuel supplier.~~

~~(C) Average annual high heat value by fuel type if measured or provided by fuel supplier, reporting in units of MMBtu per fuel unit as specified in section 95115(a)(2)(A).~~

~~(3) Indirect energy usage:~~

~~(A) Electricity purchases from each electricity provider (kWh)~~

~~(B) Steam, heat, and cooling purchases from each energy provider (Btu)~~

(b) ~~***Calculation of CO_2 Emissions.*** The operator shall calculate emissions of CO_2 as specified below.~~ *CEMS CO_2 Monitoring.* Notwithstanding the allowance of oxygen concentration monitors in 40 CFR 98.33(a)(4)(iv), an operator installing a continuous emissions monitoring system that includes a stack gas volumetric flow rate monitor after January 1, 2012 must install and use a CO_2 monitor to report CO_2 emissions. An operator without a CO_2 monitor who uses a CEMS and O_2 concentrations to calculate and report a unit's CO_2 emissions, and who conducts a Relative Accuracy Test Audit (RATA) for the unit, must at least annually include in the RATA the direct monitoring of CO_2 concentration and flow, and the calculation of CO_2 mass per hour. The operator must retain these results pursuant to the recordkeeping requirements of section 95105 and make them available to ARB upon request. The requirements of this paragraph do not apply to facilities for which pipeline natural gas is the only fuel consumed.

~~(1) The operator of a crude oil or natural gas production facility identified with the NAICS code 211111 shall report CO_2 emissions from stationary combustion according to the methods specified in sections 95125(c),(d), and(f).~~

~~(A) For natural gas and associated gas, the operator shall use the method specified in section 95125(c) or 95125(d).~~

~~(B) For low Btu gases, the operator shall report emissions resulting from the combustion and/or destruction of low Btu gases as specified in section 95113(d)(3) or section 95125(f), as applicable.~~

~~(C) For fuel mixtures, the operator shall apply the method specified in section 95125(f).~~

~~(2) For all other facilities, the operator shall measure and report CO_2 emissions from stationary combustion using one of the following methods:~~

~~(A) Use of a continuous emissions monitoring systems (CEMS) as specified in section 95125(g);~~
~~(B) Use of default emission factors and high heat values as specified in section 95125(a).~~
~~(C) Where a default high heat value is not supplied for a specific fuel type in Appendix A, the operator shall use the method provided in section 95125(c), (d), or (h) to calculate CO_2 emissions.~~
~~(D) Operators not using CEMS who co-fire two or more types of fuels shall select methods specified in sections 95115(b)(1)-(2) that enable the operator to separately report CO_2 emissions for each fuel type. Operators who co-fire with waste-derived fuels that are partly but not pure biomass may elect to determine the biomass portion of total CO_2 emissions resulting from the combustion of the co-fired fuels using the method specified in section 95125(h)(2).~~

(c) ~~***Calculation of N_2O and CH_4 Emissions.*** The operator shall calculate emissions of N_2O and CH_4 emissions from stationary combustion using the methodologies provided in section 95125(b).~~ *Choice of Tier for Calculating CO_2 Emissions.* Notwithstanding the provisions of 40 CFR §98.33(b), the operator's selection of a method for calculation of CO_2 emissions from combustion sources is subject to the following limitations by fuel type and unit size. The operator is permitted to select a higher tier than that required for the fuel type or unit size as specified below.

(1) The operator may select the Tier 1 or Tier 2 calculation method specified in 40 CFR §98.33(a) for any fuel listed in Table 1 of this section that is combusted in a unit with a maximum rated heat input capacity of 250 mmBtu/hr or less, subject to the limitation at 40 CFR §98.33(b)(1)(iv), or for biomass-derived fuels not subject to a compliance obligation under the Cap-and-Trade Regulation, when listed in Table C-1 of 40 CFR Part 98.
(2) The operator may select the Tier 2 calculation method specified in 40 CFR §98.33(a)(2) for natural gas when it is pipeline quality as defined in section 95102 of this article, and for distillate fuels listed in Table 1 of this section. Equation C-2c may be selected for the units specified in paragraph (a) of this section.
(3) The operator may select any calculation method specified in 40 CFR §98.33(a) when calculating emissions that are shown to be *de minimis* under section 95103(i)of this article, or for a fuel providing less than 10 percent of the annual heat input to a unit with a maximum rated heat input capacity of 250 mmBtu/hr or less, unless not permitted under 40 CFR §98.33(b).
(4) The operator must use either the Tier 3 or the Tier 4 calculation method specified under 40 CFR §98.33(a)(3)-(4) for any other fuel, subject to the limitations of 40 CFR §98.33(b)(4)-(5) requiring use of the Tier 4 method.

(d) ~~***Electricity Generating Units.*** Operators of general stationary combustion facilities with electricity generating units subject to the requirements of this article shall meet the requirements of section 95111.~~ *Source Test Option for N_2O and CH_4.* In lieu of other methods specified in this article, a facility operator may conduct site-specific source testing to derive emission factors and determine annual emissions of N_2O or CH_4 from any combustion source. Alternatively, the operator may use the results of an applicable test method specified in title 17, California Code of Regulations, section 95471. For source testing:

(1) The facility operator must submit to the Executive Officer a test plan at least 45 days prior to the first test date. The test plan must provide for testing at least annually, and more frequently as needed to account for seasonal variations in fuels or processes.

(2) The plan must specify conduct of performance and stack tests consistent with the requirements of approved ARB or U.S. EPA test methods. Process rates during the test must be determined in a manner that is consistent with the procedures used for GHG report accounting purposes.

(3) Upon approval of the test plan by the Executive Officer, the test procedures in that plan must be repeated as specified in the plan. The Executive Officer and the local air pollution control officer must be notified at least ten days in advance of subsequent tests.

(e) ~~***Cogeneration.*** Operators of general stationary combustion facilities with cogeneration systems subject to the requirements of this article shall meet the requirements of section 95112.~~ *Procedures for Biomass CO_2 Determination.* When combusting MSW or any other fuel for which the biomass fraction is not known, the operator must follow the procedures specified in 40 CFR §98.33(e)(3) to specify a biomass fraction.

(f) ~~***Indirect Energy Usage.*** Operators of general stationary combustion facilities shall calculate indirect electricity and thermal energy purchased or acquired and consumed as specified in sections 95125(k)-(l).~~ *Fuel Sampling Frequencies.* The operator who collects and analyzes fuel samples to conduct the monitoring analyses required under 40 CFR §98.34 must sample at the frequencies specified in that section, except in the following cases.

(1) Natural gas that is outside the range of pipeline quality as defined in section 95102 must be sampled and analyzed at least monthly by the reporting entity or the fuel supplier.

(2) Under 40 CFR §98.34(b)(3)(ii)(E), in cases where equipment necessary to perform daily sampling and analysis of carbon content and molecular weight for refinery fuel gas is not in place, such equipment must be installed and procedures established to implement daily sampling and analysis no later than January 1, 2013.

(g) *Electricity Generating and Cogeneration Units.* The operator of a facility that includes electricity generating and cogeneration units meeting the applicability criteria of section 95101 must meet the requirements specified in section 95112 of this article.

(h) *Natural Gas Provider.* The operator must report the provider(s) of natural gas to the facility, and the operator's customer account number(s).

(i) *Procedures for Missing Data.* To substitute for missing data for emissions reported under section 95115 of this article, the operator must follow the requirements of section 95129.

(j) *Additional Data to Support Benchmarking.* Operators of the following types of facilities must also report the production quantities indicated below.

(1) The operator of a facility engaged in the production and manufacture of hot rolled sheet steel, galvanized sheet steel, or both, must report the quantity of hot rolled sheet steel and galvanized sheet steel produced in the data year (short tons).
(2) The operator of a soda ash manufacturing facility must report the quantity of soda ash produced in the data year (short tons).
(3) The operator of a gypsum manufacturing facility must report quantities produced of each of the following products (short tons): dry gypsum; plaster; gypsum blocks, plasterboards and coving; and glass-fiber reinforced gypsum (GRG) plasterboards.

Table 1: Petroleum Fuels For Which Tier 1 or Tier 2 Calculation Methodologies May Be Used Under Section 95115(c)(1)

Fuel Type	*Default High Heat Value*	*Default CO_2 Emission Factor*
	mmBtu/gallon	*kg CO_2/mmBtu*
Distillate Fuel Oil No. 1	0.139	73.25
Distillate Fuel Oil No. 2	0.138	73.96
Distillate Fuel Oil No. 4	0.146	75.04
Kerosene	0.135	75.20
Liquefied petroleum gases (LPG)[1]	0.092	62.98
Propane	0.091	61.46
Propylene	0.091	65.95
Ethane	0.096	62.64
Ethylene	0.100	67.43
Isobutane	0.097	64.91
Isobutylene	0.103	67.74
Butane	0.101	65.15
Butylene	0.103	67.73
Natural Gasoline	0.110	66.83
Motor Gasoline	0.125	70.22

[1] Commercially sold as "propane" including grades such as HD5.

Table 1: Petroleum Fuels For Which Tier 1 or Tier 2 Calculation Methodologies May Be Used Under Section 95115(c)(1)

Fuel Type	*Default High Heat Value*	*Default CO_2 Emission Factor*
Aviation Gasoline	0.120	69.25
Kerosene-Type Jet Fuel	0.135	72.22

NOTE: Authority cited: Sections 39600, 39601, 39607, 39607.4, 41511, 38510, and 38530, Health and Safety Code. Reference: Sections 39600, 41511, and 38530, Health and Safety Code.

§ 95116. Glass Production.

The operator of a facility who is required to report under section 95101 of this article, and who is not eligible for abbreviated reporting under section 95103(a), must comply with Subpart N of 40 CFR Part 98 (§§98.140 to 98.148) in reporting annual stationary combustion and process emissions from glass production to ARB, except as otherwise provided in this section.

(a) *CO_2 from Fossil Fuel Combustion.* When calculating CO_2 emissions from fuel combustion, the operator must use a method in 40 CFR §98.33(a)(1) to §98.33(a)(4) as specified by fuel type in section 95115 of this article.

(b) *Monitoring, Data and Records.* For each emissions calculation method chosen under section 95116(a), the operator must meet the applicable requirements for monitoring, missing data procedures, data reporting, and records retention that are specified in 40 CFR §98.34 to §98.37, except as modified in sections 95115, 95116(c), and 95129 of this article.

(c) *Missing Data Substitution Procedures.* The operator must comply with 40 CFR §98.145 when estimating missing data, except as otherwise provided in paragraphs (1)-(3) below.

(1) To substitute for missing data for emissions reported under section 95115 of this article (stationary combustion units and units using continuous emissions monitoring systems), the operator must follow the requirements of section 95129 of this article.

(2) For each missing value of the monthly amounts of carbonate-based raw materials charged to any continuous glass melting furnace, the operator must apply a substitute value according to the procedures in paragraphs (A)-(B) below.

(A) If the data capture rate is at least 80 percent for the data year, the operator must substitute each missing value according to 40 CFR §98.145(a).

(B) If the data capture rate is less than 80 percent for the data year, the operator must substitute each missing value with the maximum tons per

day raw material capacity of the continuous glass melting furnace.

(3) The operator must document and retain records of the procedure used for all missing data estimates pursuant to the recordkeeping requirements of section 95105.

(d) *Additional Data to Support Benchmarking.* In addition to the information required by 40 CFR §98.146, the operator must report the additional parameters provided in paragraphs (1)-(2) below whether or not a CEMS is used to measure CO_2 emissions.

(1) Annual quantity of packed or sellable glass produced (short tons).
(2) Annual quantity of fiberglass produced (short tons).

NOTE: Authority cited: Sections 39600, 39601, 39607, 39607.4, 41511, 38510, and 38530, Health and Safety Code. Reference: Sections 39600, 41511, and 38530, Health and Safety Code.

§ 95117. Lime Manufacturing.

The operator of a facility who is required to report under section 95101 of this article, and who is not eligible for abbreviated reporting under section 95103(a), must comply with Subpart S of 40 CFR Part 98 (§§98.190 to 98.198) in reporting annual stationary combustion and process emissions from lime manufacturing to ARB, except as otherwise provided in this section.

(a) *CO_2 from Fossil Fuel Combustion.* When calculating CO_2 emissions from fuel combustion, the operator must use a method in 40 CFR §98.33(a)(1) to §98.33(a)(4), as specified by fuel type in section 95115 of this article.

(b) *Monitoring, Data and Records.* For each emissions calculation method chosen under section 95117(a), the operator must meet the applicable requirements for monitoring, missing data procedures, data reporting, and records retention that are specified in 40 CFR §98.34 to §98.37, except as modified in sections 95115, 95117(c), and 95129 of this article.

(c) *Missing Data Substitution Procedures.* The operator must comply with 40 CFR §98.195 when substituting for missing data, except as otherwise provided in paragraphs (1)-(2) below.

(1) To substitute for missing data for emissions reported under section 95115 of this article (stationary combustion units and units using continuous emissions monitoring systems), the operator must follow the requirements of section 95129 of this article.

(2) If CaO and MgO content data required by 40 CFR §98.193(b)(2) are missing and a new analysis cannot be undertaken, the operator must apply substitute values according to the procedures in paragraphs (A)-(C) below.

(A) If the data capture rate is at least 90 percent for the data year, the operator must substitute each missing value using the best available estimate of the parameter, based on all available process data.

(B) If the data capture rate is at least 80 percent but not at least 90 percent for the data year, the operator must substitute each missing value with the highest quality assured value recorded for the parameter during the given data year, as well as the two previous data years.

(C) If the data capture rate is less than 80 percent for the data year, the operator must substitute each missing value with the highest quality assured value recorded for the parameter in all records kept according to section 95105(a).

(3) For each missing value of the quantity of lime produced (by lime type) and quantity of lime byproduct/waste produced and sold, the operator must apply a substitute value according to the procedures in paragraphs (A)-(B) below.

(A) If the data capture rate is at least 80 percent for the data year, the operator must substitute each missing value according to 40 CFR §98.195(a).

(B) If the data capture rate is less than 80 percent for the data year, the operator must substitute each missing value with the maximum capacity of the system.

(4) The operator must document and retain records of the procedure used for all missing data estimates pursuant to the recordkeeping requirements of section 95105.

NOTE: Authority cited: Sections 39600, 39601, 39607, 39607.4, 41511, 38510, and 38530, Health and Safety Code. Reference: Sections 39600, 41511, and 38530, Health and Safety Code.

§ 95118. Nitric Acid Production.

The operator of a facility who is required to report under section 95101 of this article, and who is not eligible for abbreviated reporting under section 95103(a), must comply with Subpart V of 40 CFR Part 98 (§§98.220 to 98.228) in reporting annual stationary combustion and process emissions from nitric acid production to ARB, except as otherwise provided in this section.

(a) *CO_2 from Fossil Fuel Combustion.* When calculating CO_2 emissions from fossil fuel combustion at a stationary combustion unit under 40 CFR §98.222(b), the operator

must use a method in 40 CFR §98.33(a)(2) to §98.33(a)(4) as specified by fuel type in section 95115 of this article.

(b) *Monitoring, Data and Records.* For each emissions calculation method chosen under section 95118(a), the operator must meet the applicable requirements for monitoring, missing data procedures, data reporting, and records retention that are specified 40 CFR §98.34 to §98.37, except as modified in sections 95115, 95118(d), and 95129 of this article.

(c) *Missing Data Substitution Procedures.* The operator must comply with 40 CFR §98.225 when substituting for missing data, except as otherwise provided in paragraphs (1)-(3) below.

(1) To substitute for missing data for emissions reported under section 95115 of this article (stationary combustion units and units using continuous emissions monitoring systems), the operator must follow the requirements of section 95129 of this article.

(2) For each missing value of nitric acid production, the operator must substitute the missing data values according to the procedures in paragraphs (A)-(B) below.

(A) If the analytical data capture rate is at least 80 percent for the data year, the operator must substitute each missing value according to 40 CFR §98.225(a) and the number of days per month.

(B) If the analytical data capture rate is less than 80 percent for the data year, the operator must substitute each missing value with the maximum capacity of the system and the number of days per month.

(3) The operator must document and keep records of the procedures used for estimating missing data pursuant to the recordkeeping requirements of section 95105.

NOTE: Authority cited: Sections 39600, 39601, 39607, 39607.4, 41511, 38510, and 38530, Health and Safety Code. Reference: Sections 39600, 41511, and 38530, Health and Safety Code.

§ 95119. Pulp and Paper Manufacturing

The operator of a facility who is required to report under section 95101 of this article, and who is not eligible for abbreviated reporting under section 95103(a), must comply with Subpart AA of 40 CFR Part 98 (40 CFR §§98.270 to 98.278) in reporting annual stationary combustion and process emissions from pulp and paper manufacturing to ARB, except as otherwise provided in this section.

(a) *CO_2 from Fossil Fuel Combustion.* When calculating CO_2 emissions from fossil fuel combustion in a chemical recovery furnace at a kraft or soda facility under 40 CFR

§98.273(a)(1), a chemical recovery unit at a sulfite or stand-alone semichemical facility under 40 CFR §98.273(b)(1), a pulp mill lime kiln at a kraft or soda facility under 40 CFR §98.273(c)(1), or other stationary fuel combustion sources, the operator must use a method in 40 CFR §98.33(a)(1) to §98.33(a)(4) as specified by fuel type in section 95115 of this article.

(b) *Monitoring, Data and Records.* For each emissions calculation method chosen under section 95119(a), the operator must meet the applicable requirements for monitoring, missing data procedures, data reporting, and records retention that are specified in 40 CFR §98.34 to §98.37, except as modified in sections 95115, 95119(c), and 95129 of this article.

(c) *Procedures for Missing Data.* The operator must comply with 40 CFR §98.275 when substituting for missing data, except as otherwise provided in paragraphs (1)-(3) below.

(1) To substitute for missing data for emissions reported under section 95115 of this article (stationary combustion units and units using continuous emissions monitoring systems), the operator must follow the requirements of section 95129 of this article.

(2) For each missing value for the use of makeup chemicals (carbonates), the operator must apply a substitute value according to the procedures in paragraphs (A)-(B) below.

(A) If the data capture rate is at least 80 percent for the data year, the operator must substitute each missing value according to 40 CFR §98.275(c).

(B) If the data capture rate is less than 80 percent for the data year, the operator must substitute each missing value with the maximum metric tons per day capacity of the system.

(3) The operator must document and retain records of the procedure used for all missing data estimates pursuant to the recordkeeping requirements of section 95105.

(d) *Additional Data to Support Benchmarking.* In addition to the information required by 40 CFR §§98.276, the operator must report the annual production (short tons) of each of the following: pulp purchased or manufactured, secondary fiber from recycled paper purchased or manufactured, paper products manufactured from purchased pulp by product type, paper converted into paperboard products by product type, and the quantity of coated or laminated products by paper product type.

NOTE: Authority cited: Sections 39600, 39601, 39607, 39607.4, 41511, 38510, and 38530, Health and Safety Code. Reference: Sections 39600, 41511, and 38530, Health and Safety Code.

§ 95120. Iron and Steel Production

The operator of a facility who is required to report under section 95101 of this article, and who is not eligible for abbreviated reporting under section 95103(a), must comply with Subpart Q of 40 CFR Part 98 (40 CFR §§98.170 to 98.188) in reporting annual stationary combustion and process emissions from iron and steel production to ARB, except as otherwise provided in this section.

(a) *CO_2 from Fossil Fuel Combustion.* When calculating CO_2 emissions from fossil fuel combustion at a stationary combustion unit under §98.172(a), the operator must use a method in §98.33(a)(1) to §98.33(a)(4) as specified by fuel type in section 95115 of this article.

(b) *Monitoring, Data and Records.* For each emissions calculation method chosen under section 95120(a), the operator must meet the applicable requirements for monitoring, missing data procedures, data reporting, and records retention that are specified in 40 CFR §98.34 to §98.37, except as modified in sections 95115, 95120(c), and 95129 of this article.

(c) *Missing Data Substitution Procedures.* The operator must comply with 40 CFR §98.175 when substituting for missing data, except as otherwise provided in paragraphs (1)-(2) below.

(1) To substitute for missing data for emissions reported under section 95115 of this article (stationary combustion units and units using continuous emissions monitoring systems), the operator must follow the requirements of section 95129 of this article.

(2) If monthly mass or volume of carbon-containing inputs and outputs are missing when using the carbon mass balance procedure in 40 CFR §98.173(b)(1), the operator must apply substitute values according to the procedures in paragraphs (A)-(B) below.

(A) If the data capture rate is at least 80 percent for the data year, the operator must substitute for each missing value based on the best available estimate based on information used for accounting purposes (such as purchase records).

(B) If the data capture rate is less than 80 percent for the data year, the operator must substitute each missing value with the maximum throughput capacity of the system.

(3) The operator must document and retain records of the procedure used for all missing data estimates pursuant to the recordkeeping requirements of section 95105.

(d) *Additional Data to Support Benchmarking.* In addition to the information required by 40 CFR §§98.176, the operator must report the annual production of primary iron and steel products in metric tons and a description of the product(s).

NOTE: Authority cited: Sections 39600, 39601, 39607, 39607.4, 41511, 38510, and 38530, Health and Safety Code. Reference: Sections 39600, 41511, and 38530, Health and Safety Code.

§ 95121. Suppliers of Transportation Fuels.

Any position holder, enterer, refiner, or biomass-derived fuel producer who is required to report under section 95101 of this article must comply with Subpart MM of 40 CFR Part 98 (§§98.390 to 98.398) in reporting annual emissions to ARB, except as otherwise provided in this section.

(a) *GHGs to Report.*

(1) In addition to the CO_2 emissions specified under 40 CFR §98.392, all refiners that produce liquefied petroleum gas must report the CO_2, CH_4, N_2O and CO_2e emissions that would result from the complete combustion or oxidation of the annual quantity of liquefied petroleum gas (ex refinery gate), except for products for which a final destination outside California can be demonstrated.

(2) Refiners, position holders, and enterers of fossil fuels and biomass-derived fuels and producers of biomass-derived 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 petroleum product or biomass-derived fuel listed in Tables MM-1 or MM-2 of 40 CFR Part 98, except that distillate fuel oil is limited to diesel fuel as defined in this regulation and except for products for which a final destination outside California can be demonstrated. No fuel shall be reported as finished fuel. Fuels must be reported as the blendstock or diesel fuel plus any other components.

(b) *Calculating GHG emissions.*

(1) Refiners, position holders at California terminals, enterers who bring fuel into California outside the bulk transfer/terminal system, and biomass-derived fuel producers must use Equation MM-1 as specified in 40 CFR §98.393(a)(1) to estimate the CO_2 emissions that would result from the complete combustion of the product removed from the rack (for refiners and position holders), imported (by enterers), sold to unlicensed entities as specified in section 95121(d)(3) (by refiners), or produced (by biomass-derived fuel producers). For fuels that are mixtures of multiple components, emissions must be reported for each individual component separately, and not as finished motor gasoline, biofuel blends, or other similar finished fuel. Emission factors must be taken from column C of 40 CFR Part 98 Table MM-1 as specified in Calculation Method 1 of 40 CFR §98.393(f)(1).

(2) Refiners that produce liquefied petroleum gas must use Equation MM-1 as specified in 40 CFR §98.393(a)(1) to estimate the CO_2 emissions that would result from the complete combustion of the product supplied. For calculating the emissions from liquefied petroleum gas, the emissions from the individual components must be summed. Emission factors must be taken from column C of 40 CFR Part 98 Table MM-1 as specified in Calculation Method 1 of 40 CFR §98.393(f)(1).

(3) Refiners, position holders at California terminals, enterers outside of the bulk transfer/terminal system, and biomass-derived fuel producers must estimate and report CH_4 and N_2O emissions using Equation C–8 and Table C-2 as described in 40 CFR §98.33(c)(1).

(4) All fuel suppliers in this section must estimate CO_2e emissions using the following equation:

$$CO_2e = \sum_{i=1}^{n} GHG_i \times GWP_i$$

Where:

CO_2e = Carbon dioxide equivalent, metric tons/year.

GHG_i = Mass emissions of CO_2, CH_4, N_2O from fuels combusted or oxidized.

GWP_i = Global warming potential for each greenhouse gas from Table A-1 of 40 CFR Part 98.

n = Number of greenhouse gases emitted.

(c) *Monitoring and QA/QC Requirements.* For the emissions calculation method chosen under section 95121(b), the operator must meet all the monitoring and QA/QC requirements as specified in 40 CFR §98.394, and the requirements of 40 CFR §98.3(i) as further specified in section 95103 of this article and below.

(1) Position holders are exempt from 40 CFR §98.3(i) calibration requirements except when the fuel supplier and fuel receiver have common ownership or are owned by subsidiaries or affiliates of the same company. In such cases the 40 CFR §98.3(i) calibration requirements apply, unless:

(A) The fuel supplier does not operate the fuel billing meter;

(B) The fuel billing meter is also used by companies that do not share common ownership with the fuel supplier; or

(C) The fuel billing meter is sealed with a valid seal from the county sealer of weights and measures and the operator has no reason to suspect inaccuracies.

(2) As required by 40 CFR §98.394(a)(1)(iii), for products that are liquid at 60 degrees Fahrenheit and one standard atmosphere, the volume reported must be temperature- and pressure-adjusted to these conditions. For liquefied petroleum gas the volume reported must be temperature-adjusted to 60 degrees Fahrenheit.

(d) *Data Reporting Requirements.* In addition to reporting the information required in 40 CFR §98.3(c), the following entities must also report the information identified below:

(1) California position holders must report the annual quantity in barrels, as reported by the terminal operator, and as corrected to reflect the individual components of the product, for each petroleum product or biomass-derived fuel listed in Tables MM-1 and MM-2 of 40 CFR Part 98 that is delivered across the rack in California, except that distillate fuel oil is limited to diesel fuel and except for products for which a final destination outside California can be demonstrated.

(2) California position holders that are also terminal operators and refiners with on-site racks must report the annual quantity in barrels delivered across the rack corrected to reflect the individual components of the product, for each petroleum product or biomass-derived fuel listed in Tables MM-1 and MM-2 of 40 CFR Part 98, except distillate fuel oil is limited to diesel fuel and except for products for which a final destination outside California can be demonstrated.

(3) Refiners that supply fuel within the bulk transfer system to entities not licensed by the California Board of Equalization as a fuel supplier must report the annual quantity in barrels delivered corrected to reflect the individual components of the product, for each petroleum product or biomass-derived fuel listed in Tables MM-1 and MM-2 of 40 CFR Part 98, except Distillate Fuel Oil is limited to diesel fuel and except for products for which a final destination outside California can be demonstrated.

(4) Enterers must report the annual quantity in barrels, as reported on the bill of lading or other shipping documents, corrected to reflect the individual components of the product, for each petroleum product or biomass-derived fuel listed in Tables MM-1 and MM-2 of 40 CFR Part 98 that is imported into California, except that distillate fuel oil is limited to diesel fuel and except for products for which a final destination outside California can be demonstrated.

(5) Producers of biomass-derived fuels in California must report the annual quantity in barrels, as measured at a custody transfer meter or listed on a bill of lading, corrected to reflect the individual components of the product, for each fuel listed in Tables MM-1 and MM-2 of 40 CFR Part 98 that is delivered in California, except for products for which a final destination outside California can be demonstrated. This requirement does not apply to the annual reporting of the total volume of biodiesel, renewable diesel, and denatured fuel ethanol produced or imported, if this information has been provided under the requirements of title 17, California Code of Regulations, sections 95480-95490 (Low Carbon Fuel Standard).

(6) Biomass-derived fuel producers in California that blend biomass-derived fuel with fossil fuels outside the bulk transfer/terminal system must indicate the supplier or source of the fossil-based fuels when reporting component volumes.

(7) In addition to the information required in 40 CFR §98.396 petroleum refineries must also report the volume of liquefied petroleum gas in barrels supplied in

California as well as the volumes of the individual components as listed in 40 CFR 98 Table MM-1, except for products for which a final destination outside California can be demonstrated.

(8) All fuel suppliers identified in this section must also report CO_2, CO_2 from biomass-derived fuels, CH_4, N_2O and CO_2e emissions in metric tons that would result from the complete combustion or oxidation of each petroleum product, liquefied petroleum gas, or biomass-derived fuel reported in this section, calculated according to section 95121(b).

(9) Enterers and biomass-derived fuel producers who deliver fuel to position holders at terminals or refiners must report the name of the recipient and the volumes delivered according to the bill of lading or other sales document.

(e) *Procedures for Missing Data.* For quantities of fuels that are purchased, sold, or transferred in any manner, fuel suppliers must follow the missing data procedures specified in 40 CFR §98.395. The supplier must document and retain records of the procedure used for all missing data estimates pursuant to the recordkeeping requirements of section 95105. If any combination of data elements used to measure emissions from fuel or direct measurement are missing, such that more than 20 percent of annual emissions cannot be directly calculated, a nonconformance occurs for the emissions source. The missing data must still be substituted as specified in 40 CFR §98.395. For the purpose of applying this provision, data substituted using an approved interim data collection procedure will be considered captured data and not count toward the 20 percent missing data limitation.

NOTE: Authority cited: Sections 39600, 39601, 39607, 39607.4, 41511, 38510, and 38530, Health and Safety Code. Reference: Sections 39600, 41511, and 38530, Health and Safety Code.

§ 95122. Suppliers of Natural Gas, Natural Gas Liquids, and Liquefied Petroleum Gas.

Any supplier of natural gas or natural gas liquids who is required to report under section 95101 must comply with Subpart NN of 40 CFR Part 98 (§§98.400 to 98.408) in reporting annual emissions to ARB, except as otherwise provided in this section.

(a) *GHGs to Report.*

(1) In addition to the CO_2 emissions specified under 40 CFR §98.402(a), natural gas liquid fractionators must report the CO_2, CH_4, N_2O and CO_2e emissions that would result from the complete combustion or oxidation of liquefied petroleum gas sold or delivered to others, except for products for which a final destination outside California can be demonstrated.

(2) In addition to the CO_2 emissions specified under 40 CFR §98.402(b), local distribution companies must report the CO_2, CO_2 from biomass-derived fuels, CH_4, N_2O, and CO_2e emissions from the complete combustion or oxidation of

the annual volume of natural gas provided to all entities on their distribution systems in California

(3) The California consignee for liquefied petroleum gas will report the CO_2, CH_4, N_2O and CO_2e emissions that would result from the complete combustion or oxidation of the annual quantity of liquefied petroleum gas imported into the state, except for products for which a final destination outside California can be demonstrated.

(b) *Calculating GHG Emissions.*

(1) Natural gas liquid fractionators must use calculation methodology 1 as specified in 40 CFR §98.403(a)(1) or calculation methodology 2 as specified in 40 CFR §98.403(a)(2) to estimate the CO_2 emissions that would result from the complete combustion of the product supplied. For calculating the emissions from liquefied petroleum gas, the fractionators must sum the emissions from the individual constituents. For components of liquefied petroleum gas not listed in Table NN-1 of 40 CFR 98, values from Tables MM-1 and C-1 of 40 CFR 98 must be used as appropriate.

(2) Local distribution companies must estimate CO_2 emissions at the state border or city gate for pipeline quality natural gas using calculation methodology 1 as specified in 40 CFR §98.403(a)(1), using the reporter specific weighted yearly average higher heating value and a default or reporter specific CO_2 emission factor. Receipts of pipeline quality natural gas from in-state natural gas producers and net volume of pipeline quality natural gas injected into storage are estimated according to 40 CFR §98.403(b)(3) using reporter specific emission factors. For 40 CFR §98.403(b)(3), reporter specific emission factors will be calculated as the product of the local distribution company's own weighted yearly average HHV measurement and the default emission factor, from Table NN-1 of 40 CFR Part 98, or reporter specific CO_2 emission factor for natural gas. Alternatively, local distribution companies may estimate CO_2 emissions from pipeline quality natural gas at the city gate as the sum of the products of the volume of gas received at each city gate and the reporter specific HHV measurement at the receipt location recorded at a minimum of a monthly frequency multiplied by the default emission factor from Table NN-1 of 40 CFR Part 98, or reporter specific CO_2 emission factor for natural gas. Receipts from in-state natural gas producers and net volume of natural gas injected into storage may also be estimated according to the above method. For natural gas outside the range of 970-1100 Btu/scf the local distribution company must estimate CO_2 emissions using the Tier 3 methodologies specified in 40 CFR §98.33(a)(3)(iii) with monthly carbon content samples used to calculate the annual carbon content as specified in 40 CFR §98.33(a)(2)(ii)(A).

When calculating total CO_2 emissions for California, the equation below must be used:

$$CO_2 = \sum CO_{2i} - \sum CO_{2l}$$

Where:
CO_2 = Total emissions
CO_{2i} = Emissions from natural gas received at the state border or city gate
CO_{2l} = Emissions from storage and direct deliveries from producers

For the purpose of this section, a public utility gas corporation may use the California border as the city gate.

(3) Natural gas liquid fractionators and local distribution companies must estimate and report CH_4 and N_2O emissions using equation C-8 and Table C-2 as described in 40 CFR §98.33(c)(1) for all fuels where annual CO_2 emissions are required to be reported by 40 CFR §98.406 and this section. Local distribution companies must use the reporter specific weighted yearly average higher heating value when calculating emissions.

(4) Local distribution companies must separately and individually calculate end-user emissions of CH_4, N_2O, CO_2 from biomass-derived fuels, and CO_2e by replacing CO_2 in the equation in section 95122(b)(2) with CH_4, N_2O, CO_2 from biomass-derived fuels, and CO_2e.

(5) The California consignee for liquefied petroleum gas must use calculation methodology 2 described in 40 CFR §98.403(a)(2) for calculating CO_2 emissions. The consignee must sum the emissions from the individual components of the liquefied petroleum gas, to calculate the total emissions. For components of liquefied petroleum gas not listed in Table NN-1 of 40 CFR 98, values from Tables MM-1 and C-1 of 40 CFR 98 must be used as appropriate. If the composition is not supplied by the producer, the consignee must use the default value for liquefied petroleum gas presented in Table C-1 of 40 CFR Part 98.

(6) The California consignee for liquefied petroleum gas must estimate and report CH_4 and N_2O emissions using equation C-8 and Table C-2 as described in 40 CFR §98.33(c)(1).

(7) All fuel suppliers in this section must also estimate CO_2e emissions using the following equation

$$CO_2e = \sum_{i=1}^{n} GHG_i \times GWP_i$$

Where:
CO_2e = Carbon dioxide equivalent, metric tons/year.
GHG_i = Mass emissions of CO_2, CH_4, N_2O from fuels combusted or oxidized.
GWP_i = Global warming potential for each greenhouse gas from Table A-1 of 40 CFR Part 98.
n = Number of greenhouse gases emitted.

(c) *Monitoring and QA/QC Requirements.* For each emissions calculation method chosen under this section, the supplier must meet all monitoring and QA/QC

requirements specified in 40 CFR §98.404, except as modified in sections 95103, 95115, and below.

(1) All natural gas suppliers must measure required values at least monthly.
(2) All natural gas suppliers must determine reporter specific HHV at least monthly, or if the local distribution company does not make its own measurements according to standard business practices it must use the delivering pipeline measurement.
(3) All natural gas liquid fractionators must sample for composition at least monthly.
(4) All California consignees of liquefied petroleum gas must record composition, if provided by the supplier, and quantity in barrels, corrected to 60 degrees Fahrenheit, for each shipment received.

(d) *Data Reporting Requirements.*

(1) For the emissions calculation method selected under section 95122(b), natural gas liquid fractionators must report, in addition to the data required by 40 CFR §98.406(a), the annual volume of liquefied petroleum gas, corrected to 60 degrees Fahrenheit, sold or delivered to others, except for products for which a final destination outside California can be demonstrated. Natural gas liquid fractionators must report the annual quantity of liquefied petroleum gas delivered to others as the total volume in barrels as well as the volume of its individual components for all components listed in 40 CFR 98 Table MM-1. Fractionators must also include the annual CO_2, CH_4, N_2O, and CO_2e mass emissions (metric tons) from the volume of liquefied petroleum gas reported in 40 CFR §98.406(a)(5) as modified by this regulation, calculated in accordance with section 95122(b)(1)-(3).
(2) For the emissions calculation method selected under section 95122(b), local distribution companies must report all the data required by 40 CFR §98.406(b) subject to the following modifications:

(A) Publicly-owned natural gas utilities that report in-state receipts at the city gate under 40 CFR §98.406(b)(1) must also identify each delivering entity by name and report the monthly volumes received in Mscf and the monthly weighted average HHV.
(B) Local distribution companies that report under 40 CFR §98.406(b)(1) through (b)(7) must also report the annual energy of natural gas in MMBtu associated with the volumes.
(C) In addition to the requirements in 40 CFR §98.406(b)(8), local distribution companies must also include CO_2, CO_2 from biomass-derived fuels, CH_4, N_2O, and CO_2e annual mass emissions in metric tons calculated in accordance with 40 CFR §98.403(a) and (b)(1) through (b)(3) as modified by section 95122(b).
(D) For each publicly-owned natural gas utility, local distribution companies must report the monthly volumes, monthly weighted average HHV, and

the information required in 40 CFR §98.406(b)(12), including EIA number. These requirements are in addition to the requirements of 40 CFR §98.406(b)(6).

(E) For each customer, local distribution companies that report under 40 CFR §98.406 (b)(7) must report the annual volumes in Mscf, annual energy in MMBtu, and customer information required in 40 CFR §98.406(b)(12).

(F) Local distribution companies that report under 40 CFR §98.406(b)(9) must report annual CO_2, CO_2 from biomass-derived fuel, CH_4, N_2O, and CO_2e emissions (metric tons) that would result from the complete combustion or oxidation of the natural gas supplied to all entities calculated in accordance with section 95122(b)(2), (b)(4), and (b)(7).

(3) In addition to the information required in 40 CFR §98.3(c), the operator of non-utility interstate pipelines must report the customer name, address, and customer number along with monthly volumes of natural gas, in Mscf, and the corresponding weighted average monthly HHV in Btu/scf for natural gas delivered to each end user or wholesale customer, including themselves.

(4) In addition to the information required in 40 CFR §98.3(c), the operator of an intrastate pipeline not subject to Subpart NN of 40 CFR Part 98 that delivers natural gas directly to end users or wholesale customers must follow the reporting requirements described under Subpart NN and this section for local distribution companies. In lieu of the information specified by 40 CFR §98.406(b)(1), the operator must report volumes (Mscf) of natural gas received by the intrastate pipeline from interconnects with local distribution companies, interstate pipelines, or other intrastate pipelines.

(5) In addition to the information required in 40 CFR §98.3(c), the California consignee for liquefied petroleum gas must report the annual quantity of liquefied petroleum gas imported as the total volume in barrels as well as the volume of its individual components for all components listed in 40 CFR 98 Table MM-1, if supplied by the producer, and report CO_2, CH_4, N_2O, and CO_2e annual mass emissions in metric tons using the calculation methods in section 95122(b).

(e) *Procedures for estimating missing data.* Suppliers must follow the missing data procedures specified in 40 CFR §98.405. The operator must document and retain records of the procedure used for all missing data estimates pursuant to the recordkeeping requirements of section 95105. If any combination of data elements used to measure emissions from fuel or direct measurement is missing, such that more than 20 percent of annual emissions cannot be directly calculated, a nonconformance occurs for the emissions source. The missing data must still be substituted as specified in this section. For the purpose of applying this provision, data substituted using an approved interim data collection procedure will be considered captured data and not count toward the 20 percent missing data limitation.

NOTE: Authority cited: Sections 39600, 39601, 39607, 39607.4, 41511, 38510, and 38530, Health and Safety Code. Reference: Sections 39600, 41511, and 38530, Health and Safety Code.

§ 95123. Calculation Methods for Suppliers of Carbon Dioxide.

Any supplier of carbon dioxide who is required to report under section 95101 of this article must comply with Subpart PP of 40 CFR Part 98 (§§98.420 to 98.428) in reporting to ARB, except as otherwise provided in this section.

(a) When reporting imported and exported quantities of CO_2 as required in 40 CFR §98.422, the supplier must also report quantities of carbon dioxide imported into or exported from the State of California.

(b) *Missing Data Substitution Procedures.* The supplier must comply with 40 CFR §98.165 when substituting for missing data, except as otherwise provided below.

(1) For all data required for emissions calculations in this section, the supplier must follow the requirements of paragraphs (A)-(D) below.

(A) If the data capture rate is at least 90 percent for the data year, the supplier must substitute each missing value using the best available estimate of the parameter, based on all available process data.

(B) If the data capture rate is at least 80 percent but not at least 90 percent for the data year, the supplier must substitute each missing value with the highest quality assured value recorded for the parameter during the given data year, as well as the two previous data years.

(C) If the data capture rate is less than 80 percent for the data year, the supplier must substitute each missing value with the highest quality assured value recorded for the parameter in all records kept according to section 95105(a).

(D) The supplier must document and retain records of the procedure used for all missing data estimates pursuant to the recordkeeping requirements of section 95105.

NOTE: Authority cited: Sections 39600, 39601, 39607, 39607.4, 41511, 38510, and 38530, Health and Safety Code. Reference: Sections 39600, 41511, and 38530, Health and Safety Code.

Subarticle 3
Additional Requirements for Reported Data

§95125. Additional Calculation Methods.

[Repealed]

~~**§ 95125. *Additional Calculation Methods.***~~ ~~Operators shall use one or more of the following methods to calculate emissions as required in sections 95110 through 95115.~~

~~(a) **Method for Calculating CO_2 Emissions from Fuel Combustion Using Default Emission Factors and Default Heat Content.**~~

~~(1) The operator shall use the method in section 95125(a)(2) to calculate CO_2 emissions, applying the default emission factors and default heat content values provided in the Appendix A, for each type of fuel combusted at the facility.~~

~~(2) The operator shall calculate each fuel's CO_2 emissions and report them in metric tonnes using the following equation:~~

~~$$CO_2 = Fuel * HHV_D * EF_{CO2} * 0.001$$~~

~~Where:~~

~~CO_2 = CO_2 emissions from a specific fuel type, metric tonnes CO_2 per year~~
~~Fuel = Mass or volume of fuel combusted specified by fuel type, unit of mass or volume per year~~
~~HHV_D = Default high heat value specified by fuel type supplied by ARB, MMBtu per unit of mass or volume~~
~~EF_{CO2} = Default carbon dioxide emission factor provided in Appendix A, kg CO_2 per MMBtu~~
~~0.001 = Factor to convert kg to metric tonnes~~

~~(b) **Method for Calculating CH_4 and N_2O Emissions from Fuel Combustion Using Default Emission Factors.**~~

~~(1) The operator shall use the methods in this section to calculate CH_4 and N_2O emissions, applying the default emission factors provided in the Appendix A for each type of fuel, except as provided in section 95125(b)(4). If the operator measures heat content as specified in section 95125(c), the measured heat content shall be used in the equation in section 95125(b)(2). If the heat content is not measured, the operator shall employ the default heat content values specified in Appendix A by fuel type and the equation specified in section 95125(b)(3). If an operator combusts a fuel whose heat content is not provided in Appendix A, the operator shall measure heat content as specified by fuel type in section 95125(c) and utilize the N_2O and CH_4 emissions methodology~~

specified in section 95125(b)(2). Operators may elect to determine N_2O and CH_4 emissions using the method specified in section 95125(b)(4) in lieu of the methods provided in sections 95125(b)(2)-(3).

(2) If the heat content of the fuel is measured, the operator shall calculate each fuel's CH_4 and N_2O emissions and report them in metric tonnes using the following equation:

$$CH_4 \text{ or } N_2O = \sum_{1}^{n} Fuel_P * HHV_P * EF * 0.001$$

Where:

CH_4 or N_2O = combustion emissions from specific fuel type, metric tonnes CH_4 or N_2O per year

n = Period/frequency of heat content measurements over the year (e.g. monthly n = 12)

$Fuel_P$ = Mass or volume of fuel combusted for the measurement period specified by fuel type, units of mass or volume per unit time

HHV_P = High heat value measured for the measurement period specified by fuel type, MMBtu per unit mass or volume

EF = Default CH_4 or N_2O emission factor provided in Appendix A, kg CH_4 or N_2O per MMBtu

0.001 = Factor to convert kg to metric tonnes

(3) If the heat content of the fuel is not measured, the operator shall calculate each fuel's CH_4 and N_2O emissions and report them in metric tonnes using the following equation:

$$CH_4 \text{ or } N_2O = Fuel * HHV_D * EF * 0.001$$

Where:

CH_4 or N_2O = CH_4 or N_2O emissions from a specific fuel type, metric tonnes CH_4 or N_2O per year

Fuel = Mass or volume of fuel combusted specified by fuel type, unit of mass or volume per year

HHV_D = Default high heat value specified by fuel type provided in Appendix A, MMBtu per unit of mass or volume

EF = Default emission factor provided in Appendix A, kg CH_4 or N_2O per MMBtu

0.001 = Factor to convert kg to metric tonnes

(4) The operator may elect to calculate CH_4 and N_2O emissions using ARB approved source specific emission factors derived from source tests conducted at least annually under the supervision of ARB or the local air pollution control district or air quality management district. Upon approval of a source test plan by ARB, the source test procedures in that plan shall be repeated in future

~~years to update the source specific emission factors annually. In the absence of source specific emission factors approved by ARB, the operator shall use the default emission factors provided in Appendix A.~~

~~(c) **Method for Calculating CO_2 Emissions from Fuel Combustion Using Measured Heat Content.**~~

~~(1) The operator shall use the following equation to calculate fuel combustion CO_2 emissions by fuel type using the measured heat content of the fuel combusted:~~

$$CO_2 = \sum_{1}^{n} Fuel_p * HHV_p * EF * 0.001$$

~~Where:~~

~~CO_2 = combustion emissions from specific fuel type, metric tonnes CO_2 per year~~

~~n = Period/frequency of heat content measurements over the year (e.g. monthly n = 12)~~

~~$Fuel_p$ = Mass or volume of fuel combusted for the measurement period specified by fuel type, units of mass or volume per unit time~~

~~HHV_p = High heat value measured for the measurement period specified by fuel type, MMBtu per unit mass or volume~~

~~EF = Default carbon dioxide emission factor provided in the Appendix A, kg CO_2 per MMBtu~~

~~0.001 = Factor to convert kg to metric tonnes~~

~~(A) The operator shall measure and record fuel consumption and the fuel's high heat value at frequencies specified by fuel type below. The operator may elect to utilize and record high heat values provided by the fuel supplier. The frequencies for measurements and recordings are as follows:~~

~~1. At receipt of each new fuel shipment or delivery or on a monthly basis for middle distillates (diesel, gasoline, fuel oil, kerosene), residual oil, liquid waste-derived fuels, and LPG (ethane, propane, isobutene, n-Butane, unspecified LPG);~~

~~2. Monthly for natural gas, associated gas, and mixtures of low Btu gas excluding refinery fuel gas. Operators combusting gases with high heat value <975 or >1100 Btu per scf including natural gas, associated gas, and mixtures of low Btu gas and natural gas, shall use the methodology provided in section 95125(d) to calculate CO_2 emissions;~~

~~3. Monthly for gases derived from biomass including landfill gas and biogas from wastewater treatment or agricultural processes.~~

4. The heat content of all solid fuels shall be measured and recorded monthly. The monthly solid fuel sample shall be a composite sample of weekly samples. The solid fuel shall be sampled at a location after all fuel treatment operations and the samples shall be representative of the fuel chemical and physical characteristics immediately prior to combustion. Each weekly sub-sample shall be collected at a time (day and hour) of the week when the fuel consumption rate is representative and unbiased. Four weekly samples (or a sample collected during each week of operation during the month) of equal mass shall be combined to form the monthly composite sample. The monthly composite sample shall be homogenized and well mixed prior to withdrawal of a sample for analysis. One in twelve composite samples shall be randomly selected for additional analysis of its discreet constituent samples. This information will be used to monitor the homogeneity of the composite.

(B) When measured by the operator or fuel supplier, high heat values shall be determined using one of the following methods:

1. For gases, use ASTM D1826-94 (Reapproved 2003), ASTM D3588-98 (Reapproved 2003), ASTM D4891-89 (Reapproved 2006), GPA Standard 2261-00 "Analysis for Natural Gas and Similar Gaseous Mixtures by Gas Chromatography." The operator may alternatively elect to use on-line instrumentation that determines heating value accurate to within ± 5.0 percent. Where existing on-line instrumentation provides only low heating value, the operator shall convert the value to high heating value as specified in section 95125(c)(1)(C).

2. For middle distillates and oil, or liquid waste-derived fuels, use ASTM D240-02 (Reapproved 2007), ASTM D240-87 (Reapproved 1991), ASTM D4809-00 (Reapproved 2005).

3. For solid biomass-derived fuels use ASTM D5865-07a.

4. For waste-derived fuels use ASTM D5865-07a or ASTM D5468-02 (Reapproved 2007). Operators who combust waste-derived fuels that are partly but not pure biomass shall determine the biomass-derived portion of CO_2 emissions using the method specified in section 95125(h)(2), if applicable

(C) Operators of facilities where currently installed on-line instrumentation provides a measure of lower heating value (LHV) but not higher heating value (HHV), shall convert LHVs (Btu/scf) to HHVs (Btu/scf) in the following manner.

~~HHV = LHV * CF~~

~~Where:~~

~~HHV = fuel or fuel mixture higher heating value (Btu/scf)~~

~~LHV = fuel or fuel mixture lower heating value (Btu/scf)~~

~~CF = conversion factor~~

~~For natural gas, operators shall use a CF of 1.11.~~

~~For refinery fuel gas and mixtures of refinery fuel gas, operators shall derive a fuel system specific CF. A weekly average CF shall be determined from either concurrent LHV instrumentation measurements and HHV determined as part of the daily carbon content determination, either by on-line instrumentation or laboratory analysis, or by the HHV/LHV ratio obtained from the laboratory analysis of the daily samples.~~

~~(d) ***Method for Calculating CO_2 emissions from Fuel Combustion Using Measured Carbon Content*** - For each type of fuel combusted at the facility, the operator shall calculate CO_2 emissions using the appropriate method below:~~

~~(1) ***Solid Fuels.***~~

~~(A) Operators combusting solid fuels shall use the following equation to calculate CO_2 emissions:~~

$$CO_2 = \sum_{1}^{12} Fuel_n * CC_n * 3.664$$

~~Where:~~

~~CO_2 = carbon dioxide emissions, metric tonnes per year~~

~~$Fuel_n$ = mass of fuel combusted in month "n," metric tonnes~~

~~CC_n = carbon content from fuel analysis for month "n," percent (e.g. 95% expressed as 0.95)~~

~~3.664 = conversion factor for carbon to carbon dioxide~~

~~(B) The carbon content of all solid fuels shall be measured and recorded monthly. The monthly solid fuel sample shall be a composite sample of weekly samples. The solid fuel shall be sampled at a location after all fuel treatment operations and the samples shall be representative of the fuel chemical characteristics combusted during the sample week. Each weekly sub-sample shall be collected at a time (day and hour) of the week when the fuel consumption rate is representative and unbiased. Four weekly samples (or a sample collected during each week of operation during the month) of equal mass shall be combined to form the monthly composite sample. The monthly composite sample shall be homogenized and well-mixed prior to withdrawal of a sample for analysis. One in twelve composite samples shall be randomly selected for additional analysis of its~~

discreet constituent samples. This information will be used to monitor the homogeneity of the composite.

(C) When measured by the operator or fuel supplier, carbon content shall be determined using the following ASTM method:

1. For coal and coke, solid biomass-derived fuels, and waste-derived fuels use ASTM 5373-02 (Reapproved 2007).

(2) ***Liquid Fuels.***

(A) Operators combusting liquid fuels shall use the following equation to calculate CO_2 emissions:

$$CO_2 = \sum Fuel_n * CC_n * 3.664 * 0.001 \quad (n = 1 \text{ to } 12)$$

Where:

CO_2 = carbon dioxide emissions, metric tonnes per year

$Fuel_n$ = volume of fuel combusted in month "n," gallons

CC_n = carbon content from fuel analysis for month "n," kg C per gallon fuel

3.664 = conversion factor for carbon to carbon dioxide

0.001 = factor to convert kg to metric tonnes

(B) The carbon content shall be measured and recorded monthly. When measured by the operator or fuel supplier, carbon content shall be determined using the following ASTM methods: For petroleum-based liquid fuels and liquid waste-derived fuels, use ASTM D5291-02 (Reapproved 2007) "Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Petroleum Products and Lubricants," ultimate analysis of oil or computations based on ASTM D3238-95 (Reapproved 2005) and either ASTM D2502-04 or ASTM D2503-92 (Reapproved 2002).

(3) ***Gaseous Fuels.*** Operators combusting gaseous fuels shall use the following equation to calculate CO_2 emissions:

$$CO_2 = \sum Fuel_n * CC_n * 1/MVC * 3.664 * 0.001 \quad (n = 1 \text{ to } 12)$$

Where:

CO_2 = carbon dioxide emissions, metric tonnes per year

$Fuel_n$ = volume of gaseous fuel combusted in month "n," scf

CC_n = carbon content from fuel analysis for month "n," kg C per kg

~~mole fuel~~

~~MVC = molar volume conversion factor (849.5 scf/kg-mole for STP of 20°C and 1 atmosphere, or 836 scf/kg-mole for STP of 60°F and 1 atmosphere)~~

~~3.664 = conversion factor for carbon to carbon dioxide~~

~~0.001 = Factor to convert kg to metric tonnes~~

~~(A) When measured by the operator or fuel supplier, carbon content shall be determined using the following ASTM methods: ASTM D1945-03 or ASTM D1946-90 (Reapproved 2006). Except for refinery fuel gas and flexicoker derived fuel gas, the carbon content shall be measured and recorded monthly. Petroleum refiners electing to use this method to calculate CO_2 emissions resulting from the combustion of refinery fuel gas shall determine refinery fuel gas carbon content (CC) a minimum of 3 times per day (every eight hours) using on-line instrumentation or discrete sample laboratory analysis. The carbon content of flexigas shall be determined once per day with either on-line instrumentation or discrete sampling and lab based analysis using one of the ASTM methods listed above. Operators shall calculate CO_2 emissions for a refinery fuel gas system and flexigas combustion in the following manner:~~

$$CO_2 = \sum_{1}^{365} Fuel_n * CC_{An\text{-}ave} * MW_{RFG\text{-}A}/MVC * 3.664 * 0.001$$

~~Where:~~

~~CO_2 = carbon dioxide emissions, metric tonnes/year~~

~~$Fuel_A$ = refinery fuel or flexigas from system A combusted on day n (scf)~~

~~$CC_{An\text{-}ave}$ = system A refinery fuel gas average daily carbon content or flexigas carbon content for day n (kg C/kg fuel)~~

~~$MW_{RFG\text{-}A}$ = average daily molecular weight of refinery fuel gas system A or flexigas molecular weight for day n~~

~~MVC = molar volume conversion factor (849.5 scf/kg-mole for STP of 20°C and 1 atmosphere, or 836 scf/kg-mole for STP of 60°F and 1 atmosphere)~~

~~3.664 = conversion factor – carbon to carbon dioxide~~

~~0.001 = conversion factor – kg to metric tonnes~~

~~(4) Operators who combust waste-derived fuels that are partly but not pure biomass and who determine CO_2 emissions using methods provided in sections 95125(d)(1)-(3) shall determine the biomass-derived portion of CO_2 emissions using the method specified in section 95125(h)(2), if applicable.~~

(e) ***Method for Calculating CO_2 Emissions from Fuel Combustion Using Measured Heat and Measured Carbon Content.***

(1) The operator shall use the following method to calculate CO_2 emissions from combustion of refinery fuel gas using both high heat value (HHV) and fuel carbon content.

(2) Each fuel gas system that provides fuel to one or more combustion devices shall be subject to the measurement and reporting methods described herein. The operator shall obtain fuel samples and choose measurement locations in a manner that minimizes bias and is representative of each fuel gas system.

(3) For each separate fuel gas system, the operator shall calculate a daily fuel specific emission factor using the equation shown below. Operators meeting the definition of "small refiner" shall calculate a weekly emission factor for each refinery fuel gas system.

$$EF_{CO2\,A} = CC_A / HHV_A * MW_A / MVC * 3.664 * 1000$$

Where:

$EF_{CO2\,A}$ = daily CO_2 emission factor for fuel gas system A (metric tonnes CO_2/MMBtu)
CC_A = fuel gas carbon content for fuel gas system A (kg carbon/kg fuel)
HHV_A = high heating value for fuel gas system A (Btu/scf)
MW_A = refinery fuel A molecular weight (kg/kg-mole)
MVC = molar volume conversion (849.5 scf/ kg-mole, for STP of 20°C and 1 atmosphere, or 836 scf/kg-mole for STP of 60°F and 1 atmosphere)
3.664 = conversion factor – carbon to carbon dioxide
1000 = conversion factor – kg/Btu to metric tonnes/MMBtu

(A) The operator shall determine carbon content once per day for each fuel gas system, by on-line instrumentation or by laboratory analysis of a representative gas sample drawn from the system, using the method specified in section 95125(d)(3). Small refiners shall determine carbon content weekly.

(B) The operator shall determine high heating value from the fuel sample obtained to conduct carbon analysis, or from continuous on-line instrumentation. When HHV_A is derived from on-line instrumentation, operators shall use either an hourly average HHV value coinciding with the hour in which the carbon content determination was made, or the hour in which the sample was collected for analysis. The operator shall use the method specified in section 95125(c)(1)(B). Operators of facilities with installed instrumentation which provides fuel or fuel mixture LHV (Btu/scf) shall use methods specified in section 95125(c)(1)(C) for the conversion of LHV to HHV.

(4) For each refinery fuel gas system the operator shall use the system specific daily (weekly for small refiners) fuel emission factor calculated using the equation in section 95125(e)(3) to calculate daily (weekly for small refiners) CO_2 emissions from all combustion devices where the fuel gas from that system was combusted, using the following equation.

$$CO_{2\text{-}A} = \sum_{1}^{365} HHV_{DA} * FR_A * EF_{CO2\text{-}A} * 0.000001$$

Where:

$CO_{2\text{-}A}$ = CO_2 emissions resulting from the combustion of fuel gas from system A (metric tonnes/yr)

HHV_{DA} = daily average high heating value for system A (Btu/scf)

FR_A = daily fuel consumption for fuel gas system A (scf/d)

$EF_{CO2\text{-}A}$ = daily CO_2 emission factor for fuel gas system A (tonnes CO_2/MM Btu)

0.000001 = conversion factor – Btu to MMBtu

The operator shall determine the daily average high heating value (HHV_{DA}) from continuous on-line instrumentation (except for small refiners). Small refiners may use the HHV value determined as part of the weekly fuel carbon content analysis to calculate weekly CO_2 emissions.

(5) The operator shall calculate and report total CO_2 emissions resulting from the combustion of fuel gas as the sum of CO_2 combustion emissions from each fuel gas system in the following manner:

$$CO_2 = CO_{2\text{-}A} + CO_{2\text{-}B} + CO_{2\text{-}C} + \ldots\ldots CO_{2\text{-}X}$$

Where:

CO_2 = total CO_2 emissions from the combustion of fuel gas (metric tonnes/yr)

$CO_{2A,B,C}$ = CO_2 emissions from the combustion sources in fuel gas system A,B,C, etc. (metric tonnes/yr)

$CO_{2\text{-}X}$ = CO_2 emissions from the combustion of fuel gas system X, where X is the total number of fuel gas systems (metric tonnes/yr)

(f) ***Method for Calculating CO_2 Emissions from Fuel Combustion for Fuel Mixtures. (Petroleum Refineries and Crude Oil and Natural Gas Processing Facilities)***

(1) Where individual fuels are mixed prior to combustion, the operator shall choose one of the methods below to calculate and report CO_2 emissions.

(A) Determine fuel flow rate and appropriate fuel specific parameters (carbon content, HHV) of each fuel stream prior to mixing, calculate CO_2 emissions for each fuel in the mixture using the appropriate methodology (specified in section 95125(c) for natural gas and associated gas, 95125(f)(1)(B)-(D) for refinery fuel gas and flexigas, and 95113(d)(3) for low Btu gas) and sum individual fuel emissions to calculate emissions resulting from combustion of the mixture.

(B) Determine CO_2 emissions using a Continuous Emissions Monitor System (CEMS) as specified in section 95125(g).

(C) Operators of petroleum refineries where refinery fuel gas is mixed with natural gas and/or low Btu gas shall use the methods specified in sections 95125(d)(3)(A) or 95125(e).

(D) Operators of oil and gas production facilities and natural gas production and processing facilities where associated gas or low Btu gas is mixed with natural gas prior to combustion shall use methods specified in section 95125(c).

(g) ***Method for Calculating CO_2 Emissions Using Continuous Emissions Monitoring Systems.***

(1) The operator of a facility that combusts fossil fuels or biomass and operates continuous emissions monitoring systems (CEMS) in response to federal, state, or air pollution control district/air quality management district (AQMD/APCD) regulations, including 40 CFR Part 60 or 40 CFR Part 75, may use CO_2 or O_2 concentrations and flue gas flow measurements to determine hourly CO_2 mass emissions using methodologies provided in 40 CFR Part 75, Appendix F. The operator shall report CO_2 emissions for the report year in metric tonnes based on the sum of hourly CO_2 mass emissions over the year, converted to metric tonnes.

(A) If the operator of a facility that combusts biomass uses O_2 concentrations to calculate CO_2 concentrations, annual source testing must demonstrate that calculated CO_2 concentrations when compared to measured CO_2 concentrations meet the Relative Accuracy Test Audit (RATA) requirements in 40 CFR Part 60, Appendix B, Performance Specification 3.

(2) The operators of a facility that combusts municipal solid waste or other waste-derived fuels and operates a CEMS in response to federal, state, or AQMD/APCD regulations, including 40 CFR Part 60 or 40 CFR Part 75, may use CO_2 concentrations and flue gas flow measurements to determine hourly CO_2 mass emissions using methodologies provided in 40 CFR Part 75, Appendix F. The operator shall report CO_2 emissions for the report year in metric tonnes based on the sum of hourly CO_2 mass emissions over the year and converted to metric tonnes. Emissions calculations shall not be based on O_2 concentrations.

~~(3) The operator of a facility that combusts municipal solid waste or other waste-derived fuels who chooses to calculate CO_2 emissions using the methodology provided in section 95125(g)(2) shall determine the portion of emissions associated with the combustion of biomass-derived fuels using the method provided in section 95125(h)(2), if applicable.~~

~~(4) The operator who chooses to use CEMS data to report CO_2 emissions from a facility that co-fires fossil fuels with biomass or waste-derived fuels that are partly biomass shall determine the portion of total CO_2 emissions separately assigned to the fossil fuel and the biomass-derived fuel using the method provided in section 95125(h)(2), if applicable. The operator who co-fires pure biomass with fossil fuels may elect to calculate CO_2 emissions for the fossil fuels using methods designated in section 95111(c) by fuel type and then subtract the fossil fuel related emissions from the total CO_2 emissions determined using the CEMS based methodology.~~

~~(5) The operator who chooses to report CO_2 emissions using CEMS data is relieved of requirements to separately report process emissions from combustion emissions or to report emissions separately for different fossil fuels when only fossil fuels are co-fired. In this circumstance operators shall still report fuel use by fuel type as otherwise required in this article.~~

~~(6) If a facility is subject to requirements in 40 CFR Part 60 or 40 CFR Part 75 and the operator chooses to add devices to an existing continuous monitoring system for the purpose of measuring CO_2 concentrations or flue gas flow, the operator shall select and operate the added devices pursuant to the requirements in 40 CFR Part 60 or Part 75 that apply to the facility. If the facility is subject to both 40 CFR Part 60 and 40 CFR Part 75, the operator shall select and operate the added devices pursuant to the requirements in 40 CFR Part 75.~~

~~(7) If a facility does not have a continuous emissions monitoring system and the operator chooses to add one in order to measure CO_2 concentrations, the operator shall select and operate the CEMS pursuant to the requirements in 40 CFR Part 75. The operator shall use CO_2 concentrations and flue gas flow measurements to determine hourly CO_2 mass emissions using methodologies provided in 40 CFR Part 75, Appendix F. The operator shall report CO_2 emissions for the report year in metric tonnes based on the sum of hourly CO_2 mass emissions over the year, converted to metric tonnes. Operators who add CEMS under this article are subject to specifications in section 95125(g)(3)-(6), if applicable.~~

(h) ***Method for Calculating CO_2 Emissions from Combustion of Biomass, Municipal Solid Waste, or Waste Derived Fuels with Biomass.***

(1) The operator shall use the following method to calculate CO_2 emissions in the report year from combustion of biomass solid fuels or municipal solid waste.

(A) CO_2 emissions from combusting biomass or municipal solid waste shall be calculated using the following equation:

$$CO_2 = Heat * CC_{EF} * 3.664 * 0.001$$

Where:
CO_2 = CO_2 emissions from fuel combustion, metric tonnes per year
Heat = Heat calculated in section 95125(h)(1)(B), MMBtu per year
CC_{EF} = Default carbon content emission factor provided in Appendix A, kg carbon per MMBtu
3.664 = CO_2 to carbon molar ratio
0.001 = Conversion factor to convert kilograms to metric tonnes

(B) Heat content shall be calculated using the following equation:

$$Heat = Steam * B$$

Where
Heat = Heat, MMBtu per year
Steam = Actual Steam generated, pounds per year
B = Boiler Design Heat Input/Boiler Design Steam Output, as Design MMBtu per pound Steam

(2) The operator that combusts fuels or fuel mixtures that are at least 5 percent biomass by weight and not pure biomass, except waste-derived fuels that are less than 30 percent by weight of total fuels combusted for the report year, shall determine the biomass-derived portion of CO_2 emissions using ASTM D6866-06a as specified in this article. The operator shall conduct ASTM D6866-06a analysis at least every three months, and shall collect each gas sample for analysis during normal operating conditions over at least 24 consecutive hours. The operator shall divide total CO_2 emissions between biomass-derived emissions and non-biomass-derived emissions using the average proportionalities of the samples analyzed. If there is a common fuel source to multiple units at the facility, the operator may elect to conduct ASTM D6866-06a testing for one of the units.

(3) In lieu of the method provided in section 95125(h)(1), operators of facilities that combust biomass solid fuels, waste-derived fuels, or municipal solid waste may elect to calculate CO_2 emissions using ARB approved source specific emission

factors derived from source tests conducted at least annually under the supervision of ARB or the local air pollution control district or air quality management district. For fuels or fuel mixtures that contain at least 5 percent biomass by weight but are not pure biomass, the source test protocol shall include determination of the biomass-derived portion of CO_2 emissions as specified in section 95125(h)(2) if applicable. Upon approval of a source test plan by ARB, the source test procedures in that plan shall be repeated in subsequent years to update the source specific emission factors annually. In the absence of source specific emission factors approved by ARB, the operator shall determine CO_2 emissions using a method otherwise specified for the source in this article.

(i) ***Method for Calculating Mobile Combustion Emissions.***

(1) For operators choosing to report mobile source combustion emissions, the operator shall use the following equation to compute mobile combustion CO_2 emissions for the report year by fuel type:

$$CO_2 = Fuel * EF_{CO2} * 0.001$$

Where:

CO_2 = emissions from mobile combustion by fuel type, metric tonnes per year

Fuel = volume of fuel consumed, gallons per year

EF_{CO2} = default emission factor by fuel type provided in Appendix A, kg CO_2/gallon

0.001 = conversion factor to convert kg to metric tonnes

(2) The operator shall obtain data on the volume of fuel consumed during the report year from fuel records data (including bulk fuel purchase records, collected fuel receipts, official logs of vehicle fuel gauges or storage tanks) as shown in section 95125(i)(2)(A), unless the operator elects to calculate fuel use from miles traveled per vehicle using the fuel economy method shown in section 95125(i)(2)(B).

(A) The operator shall use the following equation to calculate mobile source fuel consumption from fuel records data:

$$Fuel = FP + FS_{beg} - FS_{end}$$

Where:

Fuel = volume of fuel consumed, gallons per year

FP = total fuel purchases, gallons per year

FS_{beg} = amount of fuel stored at the beginning of the year, gallons

FS_{end} = amount of fuel stored at the end of the year, gallons

(B) The operator shall use the following equation to calculate mobile source fuel consumption using U.S. EPA fuel economy values for specific vehicle models and miles traveled per vehicle:

$$Fuel = \sum_{i}^{n} Mileage_i / (FE_{city,i} * DP_{city,i} + FE_{highway,i} * DP_{highway,i})$$

Where:

Fuel = volume of fuel consumed, gallons per year

$Mileage_i$ = total miles traveled by vehicle i, miles per year

$FE_{city,i}$ = U.S. EPA specified vehicle i fuel economy for city driving, miles per gallon

$DP_{city,i}$ = proportion of miles traveled spent in city driving conditions for vehicle i, percent/100 (0.55 may be used as a default value or a fleet specific number may be substituted if known)

$FE_{highway,i}$ = U.S. EPA specified vehicle i fuel economy for highway driving, miles per gallon

$DP_{highway,i}$ = proportion of miles traveled spent in highway driving conditions for vehicle i, percent/100 (0.45 may be used as a default value or a fleet specific number may be substituted if known)

n = total number of vehicles

(3) The operator shall use the following equation to compute mobile combustion CH_4 and N_2O emissions by vehicle type:

$$TE = EF * Mileage * 0.000001$$

Where:

TE = total emissions of CH_4 or N_2O from mobile combustion by vehicle type, metric tonnes per year

EF = emission factor by vehicle type and fuel type provided in Appendix A, g of CH_4 or N_2O/mile

Mileage = total miles traveled by vehicle type, miles per year

0.000001 = conversion factor to convert grams to metric tonnes

(A) If mile traveled data are not available, the operator may elect to back calculate total miles traveled by vehicle type from fuel usage data using U.S. EPA fuel economy values for specific vehicle models and the following equation:

$$Mileage = \sum_{i}^{n} Fuel_i * (FE_{city,i} * DP_{city,i} + FE_{highway,i} * DP_{highway,i})$$

Where:

Mileage = total miles traveled by vehicle type, miles per year

~~$Fuel_i$ = volume of fuel consumed by vehicle model i, gallons per year~~
~~$FE_{city,i}$ = U.S. EPA specified vehicle i fuel economy for city driving, miles per gallon~~
~~$DP_{city,i}$ = proportion of miles traveled spent in city driving for vehicle i, percent/100 (0.55 may be used as a default value or a fleet specific number may substituted if known)~~
~~$FE_{highway,i}$ = U.S. EPA specified vehicle i fuel economy for highway driving, miles per gallon~~
~~$DP_{highway,i}$ = proportion of miles traveled spent in highway driving conditions for vehicle i, percent/100 (0.45 may be used as a default value or a fleet specific number may be substituted if known)~~
~~n = number of vehicles~~

~~(j) ***Method for Calculating Fugitive CH_4 Emissions from Coal Storage.***~~

~~The operator shall calculate fugitive CH_4 emissions from coal storage using the following equation:~~

~~$CH_4 = PC * EF * CF_1 / CF_2$~~

~~Where~~
~~CH_4 = CH_4 emissions in the report year, metric tonnes per year~~
~~PC = Purchased coal in the report year, tons per year~~
~~EF = Default emission factor for CH_4 based on coal origin and mine type provided in Appendix A, scf CH_4/ton~~
~~CF_1 = Conversion factor equals 0.04228, lbs CH_4/scf~~
~~CF_2 = Conversion factor equals 2,204.6, lbs/metric ton~~

~~(k) ***Method for Calculating Indirect Electricity Usage.***~~

~~The operator of a facility that consumes electricity that is purchased or acquired from a retail provider or a facility they do not own or operate shall report electricity use and identify the provider(s) for all electricity consumed at the facility.~~

~~(1) For each electricity provider, the operator shall sum electricity use (kWh) from billing records for the report year. If the records do not begin on January 1 and end on December 31 of the report year, but span two calendar years, the facility shall pro-rate its power usage according to the fraction of days billed for each month in each year using the equation shown.~~

~~Calculating electricity use for partial months:~~

~~*Partial Month Electricity use (kWh) =*~~

~~*(electricity use (kWh) in period billed / total number days in period billed) * (number of report year days in the period billed)*~~

~~(2) The operator shall report by electricity provider the electricity consumed at the facility in kilowatt-hours (kWh).~~

~~(l) ***Method for Calculating Indirect Thermal Energy Usage.***~~

~~The operator of a facility that consumes steam, heat, and/or cooling that is purchased or acquired from a facility that they do not own or operate shall report thermal energy use and identify the provider(s) for all thermal energy consumed at the facility.~~

~~(1) For each thermal energy provider, the operator shall obtain data from the facility's thermal use records, and sum this usage for the report year. If the records do not begin on January 1 and end on December 31 of the report year, but span two calendar years, the facility shall pro-rate its indirect thermal energy usage according to the fraction of days billed for each month in each year using the equation shown.~~

~~Calculating thermal use for partial months:~~

~~*Partial Month Thermal use (Btu) = (thermal use (Btu) in period billed / total number days in period billed) * (number of report year days in the period billed)*~~

~~(2) The operator shall report by thermal energy provider the thermal energy consumed at the facility in British thermal units (Btu).~~

~~NOTE: Authority cited: Sections 39600, 39601, 41511, 38510, and 38530, Health and Safety Code. Reference: Sections 39600, 41511, and 38530, Health and Safety Code.~~

§ 95129. Substitution for Missing Data Used to Calculate Emissions from Stationary Combustion and CEMS Sources.

In lieu of the requirements for estimating missing data in Subparts C and D of 40 CFR Part 98, the operator of a facility who is reporting emissions under section 95115 or 95112 of this article, and who is not eligible for abbreviated reporting under section 95103(a), must follow the applicable procedures of this section for estimating missing or invalid data. The operator must include the substituted data in the GHG emissions data report and maintain all records, calculations, and data used to estimate substituted data according to the requirements of section 95105 and 40 CFR Part 98. Alternatively, under the limited circumstances specified in this section for equipment breakdown, the operator may request approval of an interim data collection procedure as specified in paragraphs 95129(h)-(i). For units combusting pure biomass-derived fuels, the operator

who is reporting emissions must follow either the requirements below or the requirements of 40 CFR §98.35.

(a) *Missing Data Substitution Procedures for Units Reporting Under 40 CFR Part 75.* The operator of a unit that is subject to reporting under 40 CFR Part 75 must follow the applicable missing data substitution procedures in Part 75 for CO_2 concentration, stack gas flow rate, fuel flow rate, high heat value, and fuel carbon content. Paragraphs (b) through (g) of this section do not apply to these units.

(b) *Missing Data Substitution Procedures for Other Units Equipped with CEMS.* The operator of a stationary combustion unit who monitors and reports emissions and heat input data for that unit under section 95115 of this article using Tier 4 of Subpart C (40 CFR §98.33(a)(4)) must follow the applicable missing data substitution procedures in 40 CFR Part §75.31 to 75.37 (revised as of July 1, 2009).

(c) *Missing Data Substitution Procedures for Fuel Characteristic Data.* When the applicable emissions estimation methods of this article require periodic collection of fuel characteristic data (including carbon content, high heat value, and molecular weight) the operator must demonstrate every reasonable effort to obtain a fuel characteristic data capture rate of 100 percent for each data year. When fuel characteristic data of a required fuel sample are missing or invalid, the operator must first attempt to either reanalyze the original sample or perform the fuel analysis on a backup sample, or replacement sample from the same collection period as specified in 40 CFR §98.34(a)(2)-(3), to obtain valid fuel characteristic data. If the sample collection period has elapsed and no valid fuel characteristic data can be obtained from a backup or replacement sample, the operator must substitute for the missing data the values obtained according to the procedures in paragraphs 95129(c)(1)-(3). The data capture rate for the data year must be calculated as follows for each type of fuel and each fuel characteristic parameter:

Data capture rate = S / T x 100%

Where:

S = Number of fuel samples for which valid fuel characteristic data were obtained according to the applicable sampling requirements (including sampling schedule)

T = Total number of fuel samples required by the applicable sampling requirements

(1) If the fuel characteristic data capture rate is at least 90.0 percent for the data year, the operator must substitute the arithmetic average of the values of that parameter immediately preceding and immediately following the missing data incident that are representative of the fuel type. If the "after" value has not been obtained by the time that the GHG emissions data report is due, the operator must use the "before" value for missing data substitution.

(2) If the fuel characteristic data capture rate is at least 80.0 percent but not more than 90.0 percent for the data year, the operator must substitute for each missed value with the highest valid value recorded for that type of fuel during the data year as well as the two previous data years.

(3) If the operator is unable to obtain fuel characteristic data such that less than 80.0 percent of emissions from a source are directly accounted for, a nonconformance results for the emissions source. The operator must then substitute for each missed data point the greater of the following:

(A) the highest valid value recorded for that type of fuel for all records kept under the requirements of section 95105, or

(B) the default value in Table 1 of this section (for carbon content) or Table C-1 of 40 CFR Part 98 (for high heat value). If a substitute value is not available in Table 1 of this section or Table C-1 of 40 CFR Part 98, the operator must substitute the highest value recorded for that type of fuel for all records kept pursuant to the requirements of section 95105.

Table 1. Default Carbon Content

Parameter	Missing Data Value
Anthracite Coal	*90%*
Bituminous	*85%*
Subbituminous/Lignite	*75%*
Oil	*90%*
Natural Gas	*75%*
Other Gaseous Fuels	*90%*

(d) *Missing Data Substitution.Procedures for Fuel Consumption Data.* For each fuel type, when annual fuel consumption data that meet the accuracy requirements of this article are available at the facility level, but such data are missing or invalid at the unit level, the operator must either estimate missing unit-level fuel consumption data using available process data that are routinely measured at the facility (e.g., electrical load, steam production, operating hours), or use an applicable missing data substitution procedure from paragraphs 95129(d)(1)-(3). If a portion of annual fuel consumption data at the facility level is missing or cannot be determined at the accuracy required by this article, the operator must use the applicable missing data substitution procedure from paragraphs 95129(d)(1)-(3) below.

(1) *Continuous Fuel Flow Rate Data Using Load Ranges.* The requirements of this paragraph apply to sources that combust gaseous or liquid fuels, produce electrical or thermal output, use a fuel flowmeter system to continuously measure fuel flow rate; and are equipped with a data acquisition and handling system (DAHS) that continuously records fuel flow rates and measured electrical or thermal output on an hourly basis, which enables segregation of the fuel flow rate data into bins. The operator of such sources must substitute missing fuel flow rate data according to this paragraph.

Whenever quality-assured fuel flow rate data are missing and there is no backup system available to record the fuel flow rate, the operator must use the following procedures to account for the flow rate of fuel combusted at the source for each hour during the missing data period. Before using these procedures, operators must establish load ranges for the affected sources using the procedures in paragraph (f) of this section.

When load ranges are used for estimating missing fuel flow rate data, the operator must create and maintain separate fuel-specific databases for the source. The database for each type of fuel combusted must include the hours in which the fuel is combusted alone at the source and the hours in which it is co-fired with any other fuel types. The database must record fuel flow rate and corresponding electrical output or thermal output, and assign these values into the established load bins. To be eligible to use the missing data procedures in this paragraph, measured electrical output or thermal output must be available for the hour(s) in which fuel flow rate data are missing. If output data are missing, the operator must follow the requirements of paragraph (d)(3).

(A) *Single Fuel Type.* For missing data periods that occur when only one type of fuel is being combusted, the operator must provide substitute data for each hour of the missing data period as follows: Substitute the arithmetic average of the hourly quality-assured fuel flow rate(s) measured and recorded by a fuel flowmeter system at the corresponding operating source load range during the previous 720 operating hours in which the source combusted only that same fuel. If 720 hours of fuel flow rate data are not available at the corresponding load range, the operator may combine available data with data from higher load ranges if available until 720 hours are reached. If 720 hours of quality-assured fuel flow rate data are not available when combined with higher load ranges, the operator must substitute the maximum potential fuel flow rate for each hour of the missing data period.

(B) *Multiple Fuel Types.* For missing data periods that occur when two or more different types of fuel are being co-fired, the operator must provide substitute fuel flow rate data for each hour of the missing data period as follows:

1. Substitute the maximum hourly quality-assured fuel flow rate(s) measured and recorded by a fuel flowmeter system at the corresponding operating source load range during the previous 720 operating hours when the fuel for which the flow rate data are missing was co-fired with any other type of fuel. If 720 hours of fuel flow rate data are not available at the corresponding load range, data from higher load ranges if available may be combined until 720 hours are reached. If 720 hours of quality-assured fuel flow rate data are not available when combined with higher load ranges, the operator must

substitute the maximum potential fuel flow rate for each hour of the missing data period.

2. If, during an hour in which different types of fuel are co-fired, quality-assured fuel flow rate data are missing for two or more of the fuels being combusted, apply the procedures in subparagraph (d)(1)(B)1. separately for each type of fuel.
3. If the missing data substitution required in subparagraphs (d)(1)(B)1.-2. causes the reported hourly heat input rate based on the combined fuel usage to exceed the maximum rated hourly heat input of the unit, adjust the substitute fuel flow rate value(s) so that the reported heat input rate equals the unit's maximum rated hourly heat input.

(C) *Lookback Period.* In any case where the missing data provisions of this section require substitution of data measured and recorded more than three years (26,280 clock hours) prior to the date and time of the missing data period, the operator must substitute the maximum potential fuel flow rate for each hour of the missing data period. In addition, for sources in operation less than three years (26,280 clock hours), until 720 hours of quality-assured fuel flowmeter data are available for the lookback periods described in subparagraphs (d)(1)(A) and (d)(1)(B), the methodology in section (d)(3) must be used to determine the appropriate substitute data values.

(2) *Fuel Consumption Data Without Load Ranges.* This paragraph applies to fuel combusting units that cannot use the missing data procedures in paragraph (d)(1). Whenever quality-assured fuel consumption data are missing and there is no backup system available to record the fuel consumption, the operator must use the procedures in this paragraph to account for the consumption of fuel combusted at the unit during the missing data period. To be eligible to use the missing data procedures in this paragraph (d)(2), the operator must monitor and keep records of fuel consumption on a regular basis. For fuels that are combusted less than 180 days in a calendar year, the operator must record fuel consumption at least daily on each day the fuel is combusted. For all other sources or fuels, the operator must record fuel consumption at least weekly.

The data capture rate for the data year must be calculated as follows for each unit with missing fuel consumption data:

Data capture rate = S / T x 100%

Where:

S = Number of fuel monitoring periods (e.g., days or weeks) in the data year for which valid measured fuel consumption data are available. Do not include fuel monitoring periods when the fuel was not combusted at the unit.

T = Total number of fuel monitoring periods (e.g., days or weeks) that the unit is operated in the data year.

(A) *Single Fuel.* For missing data periods that occur when only one type of fuel is being combusted, the operator must provide substitute data for each missing data period as follows:

1. If the fuel consumption data capture rate is equal to or greater than 95.0 percent during the data year, the operator must develop an estimate based on available process data that are routinely measured and recorded at the unit (e.g., electrical load, steam production, operating hours).
2. If the fuel consumption data capture rate is equal to or greater than 90.0 percent but less than 95.0 percent during the data year, the operator must calculate substitute data as the 90th percentile value of the fuel consumption data recorded for the data year as well as the two previous data years.
3. If the fuel consumption data capture rate is at least 80.0 percent but less than 90.0 percent during the data year, the operator must calculate substitute data as the 95th percentile value of the fuel consumption data recorded for the data year as well as the two previous data years.
4. If the fuel consumption data capture rate is less than 80.0 percent during the data year, a nonconformance occurs for the emissions source, and the operator must apply as substitute data the maximum potential fuel consumption rate.

(B) *Multiple Fuels.* For missing data periods that occur when two or more different types of fuel are being co-fired, the operator must provide substitute fuel flow rate data for each missing data period as follows:

1. If the fuel consumption data for a single fuel are missing, provide substitute fuel consumption data for the missing data period using the procedures in paragraph 95129(d)(2)(A).
2. If fuel consumption data are missing for two or more of the fuels being combusted, apply the procedures in section 95129(d)(2)(A) (as applicable) separately for each type of fuel.
3. If the missing data substitution required in section 95129(d)(2)(A)causes the reported heat input rate based on the combined fuel usage to exceed the maximum rated heat input of the source, adjust the substitute fuel consumption value(s) so that the reported heat input rate equals the source's maximum rated heat input.

(C) *Prorating Substitute Value.* When applying the procedures in subparagraphs (d)(2)(A)-(B), if an individual missing data period is

shorter than the fuel consumption data monitoring period, the operator must prorate the specified value for the fuel consumption data monitoring period by the missing data period. For example, for a unit with a missing data period length of one day but weekly fuel consumption monitoring schedule, the operator may divide the substitute value, estimated on a weekly basis, by the number of days the unit operates in a week to obtain the substitute value for the missing data day.

(3) *Alternate Missing Data Procedure for Fuel Consumption Data.* This paragraph applies to fuel combusting units that cannot use the missing data procedures in paragraphs (d)(1) and (d)(2). If fuel consumption data are missing or invalid for a fuel combusting unit, and fuel consumption data at the facility level or aggregated unit level cannot be determined at the accuracy required by this article, the operator must substitute for each hour of missing data using the maximum potential fuel consumption rate for the unit. If fuel consumption data at the facility level or at a higher aggregated-units level are available and meet the accuracy requirements of this article, the operator may estimate the missing unit-level fuel consumption data using available process data that are routinely measured at the facility (e.g., electrical load, steam production, operating hours).

(e) *Missing Data Substitution Procedures for Steam Production.* The operator of a steam-producing unit who calculates and reports emissions using Equation C-2c in 40 CFR §98.33(a)(2) must apply the procedures in this paragraph to substitute for missing steam production data, unless a backup system to record steam production is available. For sources for which steam production data are not used to calculate emissions, the operator may develop an estimate using available process data that are routinely measured and recorded at the unit (e.g., electrical load, steam production, product output, operating hours) to estimate missing steam production.

If hourly steam production data are not available at the facility, the operator must record steam production data at least weekly and use the weekly records for substituting the missing steam production data. The operator must prorate the steam data using the same procedure in paragraph (d)(2)(C).

The data capture rate for the data year must be calculated as follows for each unit with a missing data period:

Data capture rate = S / T x 100%

Where:

S = Number of monitoring intervals (e.g. hourly, daily, or weekly) with valid measured steam production data.

T = Total number of monitoring intervals that the unit is operated in the data year.

(1) If the steam production data capture rate is at least 90.0 percent during the data year, the operator must develop an estimate using available process data that are routinely measured and recorded at the unit (e.g., electrical load, steam production, product output, and operating hours).

(2) If the steam production data capture rate is at least 80.0 percent but less than 90.0 percent during the data year, the operator must calculate substitute data as the 90th percentile value of the steam production data recorded for the data year.

(3) If the steam production data capture rate is less than 80.0 percent during the data year, a nonconformance occurs for the emissions source, and the operator must substitute the highest valid steam production value recorded in all records kept according to section 95105(a).

(f) *Procedure for Establishing Load Ranges.* This paragraph is applicable to units that produce electrical output or thermal output. For a single unit, the operator must establish ten operating load ranges, each defined in terms of percent of the maximum hourly average gross load of the unit, in gross megawatts (MW). (Do not use integrated hourly gross load in MWh.) For a cogenerating unit or other unit at which some portion of the heat input is not used to produce electricity, or for a unit for which hourly average gross load in MW is not recorded separately, the operator must use the hourly gross steam load of the unit, in pounds of steam per hour at the measured temperature (°F) and pressure (psia), instead of gross MW.

Beginning with the first hour of unit operation after installation and certification of the fuel flowmeter, for each hour of unit operation the operator must record a number, 1 through 10, that identifies the operating load range corresponding to the integrated hourly gross load of the unit(s) recorded for each unit operating hour. The operator must calculate maximum values and percentile values determined by this procedure using bias adjusted values in the load ranges. When a bias adjustment is necessary for the fuel flowmeter, the operator must apply the adjustment factor to all data values placed in the load ranges. The operator must use the calculated maximum values and percentile values to substitute for missing flow rate according to the procedures in paragraph (d)(1) of this section.

(g) *Executive Officer Approved Load Range.* An operator may petition the Executive Officer for approval to use an alternate load based methodology for substituting missing data to using the procedures in paragraph 95129(d)(1). The operator must be able to prove to the satisfaction of the Executive Officer that there is a direct correlation between fuel consumption and the proposed load metric. At a minimum, the operator will have a system in place that electronically measures and records fuel consumption and load at least hourly. The alternate load metric must be a metric that can be accurately measured, correlated to fuel consumption, and divided into ten operating load ranges. In order to verify the feasibility of the methodology the Executive Officer will require at least three years of fuel consumption and load data and may request up to the maximum years of data required to be retained under section 95105(a).

(h) *Procedure for Approval of Interim Fuel Analytical Data Collection Procedure During Equipment Breakdowns.*

(1) In the event of an unforeseen breakdown of the fuel characteristic data monitoring or fuel flow monitoring equipment used to estimate emissions under this article, the Executive Officer may authorize an operator to use an interim data collection procedure under the circumstances specified below. The operator must satisfactorily demonstrate to the Executive Officer that:

(A) The breakdown may result in a loss of more than 20 percent of a fuel characteristic or fuel usage data element for the data year, and back-up sampling for affected fuel characteristics is unavailable;
(B) The affected monitoring equipment cannot be promptly repaired or replaced without shutting down a process unit significantly affecting facility operations, or the monitoring equipment must be replaced and replacement equipment is not immediately available; and,
(C) The interim procedure will not remain in effect longer than is reasonably necessary for repair or replacement of the malfunctioning monitoring equipment.

(2) An operator seeking approval of an interim data collection procedure must, within sixty days of the monitoring equipment breakdown, submit a written request to the Executive Officer that includes all of the following:

(A) The proposed start date and end date of the interim procedure;
(B) A detailed description of what data are affected by the breakdown;
(C) A discussion of the accuracy of data collected during the interim procedure compared with the data collected under the usual procedure used by the operator;
(D) A demonstration that the criteria in paragraph (h)(1) are satisfied, and operator certification that no feasible alternative procedure exists that would provide more accurate emissions data.

(3) The Executive Officer may limit the duration of the interim data collection procedure to ensure the criteria in paragraph (h)(1) are met.
(4) When reviewing an interim data collection procedure, the Executive Officer shall determine whether the accuracy of data collected under the procedure is reasonably equivalent to data collected from properly functioning monitoring equipment, and if it is not, the relative accuracy to assign for purposes of assessing possible material misstatement under section 95131 of this article. Data collected pursuant to an approved interim data collection procedure shall be considered captured data for purposes of compliance with the capture rate requirements in this section.
(5) The Executive Officer shall provide written notification to the operator of approval or disapproval of the interim data collection procedure within sixty

days of receipt of the request, or within thirty days of receipt of any additional information requested by the Executive Officer, whichever is later.

(i) *Procedure for Approval of Interim Data Collection Procedure During Breakdown for Units Equipped with CEMS.*

(1) In the event of an unforeseen breakdown of CEMS equipment at a combustion unit where the operator uses the Tier 4 Calculation Methodology (40 CFR 98.33(a)(4)) to monitor and report emissions under this article, the operator may request approval from the Executive Officer to temporarily use the Tier 2 Calculation Methodology (40 CFR 98.33(a)(2)) for natural gas, biomass, or municipal solid waste, or the Tier 3 Calculation Methodology (40 CFR 98.33(a)(3)) for other fuels, to calculate emissions during the equipment breakdown period. The operator must satisfactorily demonstrate to the Executive Officer that:

(A) The breakdown will result in a loss of more than 20 percent of the concentration, flow rate, or other information used to calculate and report annual emissions for the data year, and that back-up monitoring is unavailable;
(B) The affected monitoring equipment cannot be promptly repaired or replaced without shutting down a process unit significantly affecting facility operations, or the monitoring equipment must be replaced and replacement equipment is not immediately available; and,
(C) The interim procedure will not remain in effect longer than is reasonably necessary for repair or replacement of the malfunctioning monitoring equipment.

(2) The operator must collect fuel samples and comply with all applicable requirements of the Tier 2 or Tier 3 Calculation Methodology in 40 CFR 98.33(a)(2) or (3), as modified by section 95115 of this article, during the equipment breakdown period. Fuel characteristics data provided by the fuel suppliers can be used if available. The operator must, within sixty days of the monitoring equipment breakdown, submit a written request to the Executive Officer that includes all the following information:

(A) The proposed start date and end date of the interim procedure, including a demonstration that the interim procedure will not remain in effect longer than is reasonably necessary for repair or replacement of the malfunctioning equipment;
(B) A detailed description of what data are affected by the breakdown; and,
(C) An interim monitoring plan that meets the requirements of the Tier 3 Calculation Methodology as applicable by fuel type in section 95115.

(3) The Executive Officer may limit the duration of the interim data collection procedure to ensure the criteria in paragraph (i)(1) are met.

(4) The Executive Officer shall provide written notification to the operator of approval or disapproval of the interim data collection procedure within sixty days of receipt of the request, or within thirty days of receipt of any additional information requested by the Executive Officer, whichever is later.

(j) *Cumulative Missing Data Elements.* If any combination of data elements used to measure emissions from fuel or direct measurement is missing, such that more than 20 percent of annual emissions cannot be calculated from directly measured data, a nonconformance occurs for the emissions source. The missing data must still be substituted as specified in this section. For the purpose of applying this provision, data substituted using an approved interim data collection procedure will be considered captured data and not count toward the 20 percent missing data limitation.

NOTE: Authority cited: Sections 39600, 39601, 39607, 39607.4, 41511, 38510, and 38530, Health and Safety Code. Reference: Sections 39600, 41511, and 38530, Health and Safety Code.

Subarticle 4. Requirements for Verification of Greenhouse Gas Emissions Data Reports and Requirements Applicable to Emissions Data Verifiers; Requirements for Accreditation of Emissions Data and Offset Project Data Report Verifiers

§ 95130. Requirements for Verification of Emissions Data Reports. ~~Operators shall~~The reporting entity who is required to report under section 95101 of this article, and who is not eligible for abbreviated reporting under section 95103(a), must obtain the services of an accredited verification body for purposes of verifying each emissions data ~~reports~~report submitted under this article, as specified in section 95103(~~e~~f).

(a) *Annual Verification.*

(1) ~~Operators~~Reporting entities required to obtain annual verification services as specified in section 95103(~~e~~f) ~~shall be~~are subject to full verification requirements in the first year that verification is required in each compliance period. Upon ~~completion of~~receiving a positive verification ~~opinion~~statement under full verification requirements, the ~~operator~~reporting entity may choose to obtain ~~two years of~~ less intensive verification services. ~~This cycle may be repeated in subsequent three-year cycles, but full~~ for the remaining years of the compliance period. Full verification requirements shall apply at least once ~~every three years.~~ in each compliance period. Reporting entities subject to this section are required to obtain full verification services if any of the following apply:

(A) The emissions data report is for the 2011 data year;
(B) There has been a change in the verification body;
(C) An adverse verification statement or qualified positive verification statement was issued for the previous year;
(D) A change of ownership of the reporting entity occurred in the previous year;
(E) The total reported GHG emissions during the data year differs by greater than 25 percent relative to the preceding emission data report;
(F) The total reported MWh during the data year differs by greater than 25 percent relative to the preceding emission data report;

(2) ~~Operators~~Reporting entities subject to annual verification under section 95130 shall not use the same verification body or verifiers(s) for a period of more than six consecutive years. ~~If an operator~~, which includes any verifications conducted under this article and for the California Climate Action Registry, The Climate Registry, or Climate Action Reserve. If a reporting entity is required or elects to contract with another verification body or verifier(s), the ~~operator~~reporting entity may contract verification services from the previous verification body or verifier(s) only after not using the previous verification body or verifiers(s) for at least three years.

~~(b) *Triennial Verification.*~~

~~(1) Operators required to obtain triennial verification under section 95103(c) shall be subject to full verification requirements every year that verification is required. However, such operators may choose to obtain less intensive verification services for the two years following completion of full verification services and prior to the next three-year cycle.~~

~~(2) Operators subject to triennial verification requirements shall not use the same verification body for more than two consecutive verification cycles. If an operator is required or elects to contract with another verification body, the operator may contract verification services from the previous verification body only after not using the previous verification body for at least three years.~~

~~(c) Operators who are members of the California Climate Action Registry may use the same verification body for ARB and CCAR emissions data reports, provided that body has met both ARB and CCAR accreditation requirements. When an operator is required to rotate verification bodies by the California Climate Action Registry, the operator shall also rotate the verification body used to meet the verification requirements of this article if the operator chooses to use the same verification body.~~

NOTE: Authority cited: Sections 39600, 39601, 39607, 39607.4, 41511, 38510, and 38530, Health and Safety Code. Reference: Sections 39600, 41511, and 38530, Health and Safety Code.

§ 95131. Requirements for Verification Services.

Verification services shall be subject to the following requirements.

(a) *Notice of Verification Services.* After the Executive Officer has provided a determination that the potential for a conflict of interest is acceptable as specified in section 95133(f) and that verification services may proceed, the verification body shall submit a notice of verification services to ARB. The verification body may begin verification services for the ~~operator~~reporting entity ten working days after the notice is received by the Executive Officer, or earlier if approved by the Executive Officer in writing. In the event that the conflict of interest statement and the notice of verification services are submitted together, verification services cannot begin until ten working days after the Executive Officer has deemed acceptable the potential for conflict of interest as specified in 95133(f). The notice shall include the following information:

(1) A list of the staff who will be designated to provide verification services as a verification team, including the names of each designated staff member, the lead verifier, and all subcontractors, and a description of the roles and responsibilities each member will have during verification. If any staff change on the verification team, that information must be updated and resubmitted to ARB five days before the verification services begin with the reporting entity;

(2) Documentation that the verification team has the skills required to provide verification services for the reporting facility. This shall include a demonstration that a verification team includes at least one member accredited to provide sector specific verification services when required below:

(A) For providing verification services to ~~a retail provider or marketer~~an electric power entity, a supplier of petroleum products or biofuels, a supplier of natural gas, natural gas liquids, or liquefied petroleum gas, or a supplier of carbon dioxide, at least one verification team member must be accredited by ARB as ~~an electricity~~a transactions specialist;

(B) For providing verification services to the operator of a petroleum refinery ~~or hydrogen plant~~, hydrogen production unit or facility, or petroleum and natural gas system listed in section 95101(e), at least one verification team member must be accredited by ARB as ~~a refinery~~an oil and gas systems specialist;

(C) For providing verification services to the operator of a ~~cement plant~~facility engaged in cement production, glass production, lime manufacturing, pulp and paper manufacturing, iron and steel production, or nitric acid production, at least one verification team member must be accredited by ARB as a ~~cement plant~~process emissions specialist.

(3) General information on the ~~lead verifier and the operator~~reporting entity, including:

~~(A) The name, office address, telephone number, and e-mail address of the lead verifier;~~

~~(B)~~ (A) The name of the ~~operator~~reporting entity and the facilities and other locations that will be subject to verification services, ~~operator~~reporting entity contact, address, telephone number, and e-mail address;

~~(C)~~ (B) The industry sector~~,~~ and the ~~Standard Industrial Classification and~~ North American Industry Classification System (NAICS) ~~codes of~~code for the reporting facility;

~~(D)~~ (C) The ~~expected~~ date(s) of the on-site ~~visits~~visit, with facility address and contact information;

~~(E)~~ (D) A brief description of expected verification services to be performed, including expected completion date.

(4) If any of the information under section 95131(a)(1) or 95131(a)(3) changes after the notice is submitted to ARB, the verification body must notify ARB at least five days before the verification services start date. If any information submitted under section 95131(a)(1) or 95131(a)(3) changes during the verification services, the verification body must notify ARB before the verification statement is provided to ARB.

(b) Verification services shall include, but are not limited to, the following:

(1) *Verification Plan.* The verification team shall obtain information from the ~~operator~~reporting entity necessary to develop a verification plan. Such information shall include, but is not limited to:

(A) Information to allow the verification team to develop a general understanding of facility or entity boundaries, operations, emissions sources, and electricity or fuel transactions as applicable;
(B) Information regarding the training or qualifications of personnel involved in developing the emissions data report;
(C) Description of the specific methodologies used to quantify and report greenhouse gas emissions, electricity and fuel transactions, and ~~other required~~associated data as ~~applicable~~needed to develop the verification plan;
(D) Information about the data management system used to track greenhouse gas emissions, electricity and fuel transactions, and ~~other required~~associated data as ~~applicable.~~needed to develop the verification plan.

(2) The verification team shall develop a verification plan that includes, at a minimum:

(A) Dates of proposed meetings and interviews with reporting facility personnel;
(B) Dates of proposed site visits;
(C) Types of proposed document and data reviews;
(D) Expected date for completing verification services.

(3) The verification team shall discuss with the ~~operator~~reporting entity the scope of the verification services and request any information and documents needed for initial verification services. The verification team shall review the documents submitted and plan and conduct a review of original documents and supporting data for the emissions data report.

(4) *Site visits.* At least one ~~member of~~accredited verifier in the verification team, including the sector specialist, if applicable, shall at a minimum make one site visit, ~~in the first year of~~during each ~~three-year reporting cycle~~year full verification is required, to each facility for which an emissions data report is submitted. The verification team member(s) shall visit the headquarters or other location of central data management when the ~~operator~~reporting entity is a retail provider ~~or~~, marketer, or fuel supplier. During the site visit, the verification team member(s) shall conduct the following:

(A) The verification team member(s) shall check that all sources specified in sections 95110 to ~~95115~~95123, and 95150 to 95158, as applicable to the ~~operator~~reporting entity are identified appropriately.
(B) The verification team member(s) shall review and understand the data management systems used by the ~~operator~~reporting entity to track,

quantify, and report greenhouse gas emissions and, when applicable, electricity and fuel transactions. The verification team member(s) shall evaluate the uncertainty and effectiveness of these systems.

(C) The verification team shall ~~collect and review other information~~carry out tasks that, in the professional judgment of the team, ~~is~~are needed in the verification process~~.~~, including the following:

1. Interviews with key personnel, such as process engineers and metering experts, as well as staff involved in compiling data and preparing the emissions data report;
2. Making direct observations of equipment for data sources and equipment supplying data for sources determined in the sampling plan to be high risk;
3. Assessing conformance with fuel analytical data requirements including: fuel meter accuracy requirements, data capture, and missing data substitution requirements;
4. Reviewing financial transactions to confirm fuel and electricity purchases and sales.

(5) The verification team shall review facility operations to identify applicable greenhouse gas emissions sources. This shall include a review of the emissions inventory and each type of emission source to ~~assure~~ensure that all sources listed in sections 95110 to ~~95115~~95123 and sections 95150 to 95158 of this article are properly included in the ~~inventory~~emissions data report.

(6) ~~Operators~~Reporting entities shall make available to the verification team all information and documentation used to calculate and report emissions, fuels and electricity transactions, and other information required under this article, as applicable.

(7) ~~As applicable for retail providers and marketers~~For electricity importers and exporters, the verification team shall review electricity transaction records, including receipts of power attributed to the Northwest or Southwest region as verifiable via North American Electric Reliability Corporation (NERC) E-Tags, settlements data, or other information as confirmation of the region of origin.

(8) *Sampling Plan.* As part of confirming emissions data ~~or~~, electricity transactions, or fuel transactions the verification team shall develop a sampling plan that meets the following requirements:

(A) The verification team shall develop a sampling plan based on a strategic analysis developed from document reviews and interviews to assess the likely nature, scale and complexity of the verification services for ~~an operator~~a reporting entity. The analysis shall review the inputs for the development of the submitted emissions data report, the rigor and appropriateness of ~~the greenhouse gas or electricity transaction~~ data management ~~system~~systems, and the coordination within ~~a facility or retail provider's or marketer~~the reporting entity's organization to manage

the operation and maintenance of equipment and systems used to develop emissions data reports.

(B) The verification team shall include in the sampling plan a ranking of emissions sources by amount of contribution to total CO_2 equivalent emissions for the ~~operator~~reporting entity, and a ranking of emissions sources with the largest calculation uncertainty. As applicable and deemed appropriate by the verification team, fuel and electricity transactions shall also be ranked or evaluated relative to the amount of fuel or power exchanged and uncertainties that may apply to data provided by the ~~retail provider or marketer~~reporting entity.

(C) The verification team shall include in the sampling plan a qualitative narrative of uncertainty risk assessment in the following areas as applicable under sections 95110 to ~~95115~~95123, 95129, and 95150 to 95158:

1. Data acquisition equipment;
2. Data sampling and frequency;
3. Data processing and tracking;
4. Emissions calculations;
5. Data reporting;
6. Management policies or practices in developing emissions data reports.

(D) After completing the analyses required by sections 95131(b)(8)(A)-(C), the verification team shall include in the sampling plan a list which includes the following:

1. Emissions sources and/or transactions that will be targeted for document reviews, and data checks as specified in 95131(b)(9), and an explanation of why they were chosen;
2. Methods used to conduct data checks for each source or transaction;
3. A summary of the information analyzed in the data checks and document reviews conducted for each emissions source or transaction targeted.

The sampling plan list must be updated and finalized prior to the completion of verification services.

~~(D)~~ (E) The verification team ~~may change~~shall revise the sampling plan to describe tasks completed by the verification team as relevant information becomes available and potential issues emerge ~~of~~with material misstatement or nonconformance with the requirements of this article.

~~(E)~~ (F) The verification body shall retain the sampling plan in paper, electronic, or other format for a period of not less than ~~five~~ten years following the submission of each verification ~~opinion~~statement. The sampling plan shall be made available to ARB upon request.

(G) The verification body shall retain all material received, reviewed, or generated to render a verification statement for a reporting entity for no less than ten years. The documentation must allow for a transparent review of how a verification body reached its conclusion in the verification statement.

(9) *Data Checks.* To determine the reliability of the submitted emissions data report, the verification team shall use data checks. Such data checks shall focus ~~first~~ on the largest and most uncertain estimates of emissions and fuel and electricity transactions, and shall include the following:

(A) The verification team shall use data checks to ensure that the appropriate methodologies and emission factors have been applied for the emissions sources and fuel and electricity transactions covered under sections 95110 to ~~95115~~95123, 95129, and 95150 to 95158;

(B) The verification team shall choose for data checks emissions sources~~,~~ and fuel and electricity transactions data, as applicable, ~~for data checks~~ based on their relative ~~sizes and~~contributions to emissions and the associated risks of contributing to material misstatement or nonconformance, as indicated in the sampling plan;

(C) The verification team shall use professional judgment in the number of data checks required for the team to conclude with reasonable assurance whether the total reporting entity reported emissions ~~and transactions~~ are free of material misstatement and the emissions data report otherwise conforms to the requirements of this article. At a minimum, data checks must include the following:

1. Tracing data in the emissions data report to its origin;
2. Looking at the process for data compilation and collection;
3. Recalculating emission estimates to check original calculations;
4. Reviewing calculation methodologies used by the reporting entity for conformance with this article; and
5. Reviewing meter and fuel analytical instrumentation measurement accuracy and calibration for consistency with the requirements of section 95103(k).

The verification team shall compare its own calculated results with the reported data in order to confirm the extent and impact of any omissions and errors. Any discrepancies must be investigated. The comparison of data checks must provide enough detail to indicate which sources and transactions were checked, the types and quantity of data that were evaluated for each source and transaction, and any discrepancies that were identified.

(10) *Emissions Data Report Modifications.* ~~If as~~As a result of ~~review~~data checks by the verification team and prior to completion of a verification ~~opinion the~~

~~operator chooses to~~statement, the reporting entity must make any possible improvements or corrections to the submitted emissions data report, and submit a revised emissions data report ~~may be submitted~~ to ARB ~~as specified by section 95104(d)~~. The ~~operator~~reporting entity shall maintain documentation to support any revisions made to the initial emissions data report. Documentation for all emissions data report submittals shall be retained by the ~~operator~~reporting entity for ~~five~~ten years pursuant to section 95105.

(11) *Findings.* To verify that the emissions data report is free of material misstatement, the verification team shall make its own determination of emissions for checked sources and shall determine whether there is reasonable assurance that the ~~reported facility emissions are within 95 percent of actual total emissions for the facility~~emissions data report does not contain a material misstatement for the reporting entity, on a CO_2 equivalent basis for GHG emissions. To assess conformance with this article the verification team shall review the methods and factors used to develop the emissions data report for adherence to the ~~requirement~~requirements of this article and ensure that other requirements of this article are met.

(12) *Log of Issues.* The verification team ~~shall~~must keep a log of any issues identified in the course of verification activities that may affect determinations of material misstatement and nonconformance~~, and how those issues were resolved~~. The issues log must identify the regulatory section related to the nonconformance, if applicable, and indicate if the issues were corrected by the reporting entity prior to completing the verification. Any other concerns that the verification team has with the preparation of the emissions data report, including with any *de minimis* method calculations, must be documented in the issues log. The log of issues must indicate whether each issue has a potential bearing on material misstatement, nonconformance, or both.

(13) An assessment of material misstatement is conducted on total reported GHG emissions (metric tons of CO_2e), except those emissions without a compliance obligation as set forth in title 17, California Code of Regulations, section 95852.2.

(14) In assessing whether an emissions data report contains a material misstatement, the verification team must determine whether the total reported emissions contain a material misstatement using the following equation:

$$Percent\ accuracy = 100\% - \sum \frac{[Errors + Omissions + Misreporting]\ x\ 100\%}{Total\ reported\ emissions}$$

Where:

"Errors" means any differences between the reported emissions and verifier calculated emissions for a data source subject to data checks in 95131(b)(9).

"Omissions" means any emissions the verifier concludes must be part of the emissions data report, but were not included by the reporting entity in the emissions data report.

"Misreporting" means duplicate, incomplete or other emissions the verifier concludes should, or should not, be part of the emissions data report.

"Total reported emissions" means the total annual reporting entity CO2e emissions reported for the emission sources which hold a compliance obligation as set forth in title 17, California Code of Regulations, sections 95852 and 95852.1 for which the verifier is conducting a material misstatement assessment.

(15) The verification team must check the following for conformance as part of verifier review with the reporting requirements under this article, when applicable data checks are chosen under 95131(b)(9), but does not have to conduct a material misstatement assessment using the equation in 95131(b)(14);

(A) Total reported facility indirect electricity purchases (kWH);
(B) Total reported facility indirect thermal purchases (Btu);
(C) Total reported GHG emissions (metric tons of CO_2e) included in the emissions data report as emissions without a compliance obligation under title 17, California Code of Regulations, section 95852.2.

(16) *Review of Missing Data Substitution.* If a source selected for a data check was affected by a loss of data used to calculate GHG emissions for the data year:

(A) The verification team shall confirm that the reported emissions for that source were calculated using the applicable missing data procedures, or that an approved interim data collection procedure was used for the source.
(B) The difference between the reporting entity's calculated emissions and verifier's calculated emissions for that source will be zero when assessing for material misstatement under section 95131(b)(14), when the applicable missing data substitution procedures or interim data collection procedure has been correctly applied by the reporting entity; or, any relative accuracy assigned to the emissions estimate under section 95129(h)(4) has been correctly applied.
(C) If 20 percent or less of any combination of data elements used to measure emissions from fuel or direct measurement are missing, and emissions correctly calculated using the missing data requirements in sections 95110 to 95123, 95129, and 95150 to 95158 will be considered accurate and as meeting the reporting requirements for that source.

(D) If greater than 20 percent of the emissions for a source has been calculated from data that has been substituted according to the missing data provisions of this article, the verifier will note a non-conformance as part of the verification finding.

(c) Completion of verification services ~~shall~~must include:

(1) *Verification* ~~**Opinion**~~*Statement.* Upon completion of the verification services specified in section 95131(b), the verification body shall complete a verification ~~opinion~~statement, and provide that ~~opinion~~statement to the ~~operator~~reporting entity and the ARB ~~according to the schedule~~by the applicable verification deadline specified in section 95103(~~c~~)(~~3~~f). Before that ~~opinion~~statement is completed, the verification body shall have the verification services and findings of the verification team independently reviewed within the verification body by an independent reviewer who is a lead verifier not involved in services for that ~~operator~~reporting entity during that year.

(2) The independent reviewer shall serve as a final check on the verification team's work to identify any significant concerns, including:

(A) errors in planning,
(B) errors in data sampling, and
(C) errors in judgment by the verification team that are related to the draft verification statement.

The independent reviewer must maintain independence from the verification services by not making specific recommendations about how the verification services should be conducted. The independent reviewer will review documents relevant to the verification services provided, and identify any failure to comply with requirements of this article or with the verification body's internal policies and procedures for providing verification services. The independent reviewer must concur with the verification findings before the verification statement can be issued.

~~(2)~~ (3) When the verification team completes its findings:

(A) The verification body shall provide to the ~~operator~~reporting entity a detailed verification report. The detailed verification report shall at a minimum include the verification plan, the detailed comparison of the data checks ~~with the submitted emissions data report~~conducted during verification services, the log of issues identified in the course of verification activities and their resolution, and any qualifying comments on findings during verification services. The detailed verification report shall also include the calculation performed in section 95131(b)(14). The detailed verification report shall be made available to ARB upon request.

(B) The verification team shall have a final discussion with the reporting entity explaining its findings, and notify the reporting entity of any

unresolved issues noted in the issues log before the verification statement is finalized.

~~(B)~~ (C) The verification body shall provide the verification ~~opinion~~statement to the ~~operator~~reporting entity and the ARB, attesting ~~that~~whether the verification body has found the submitted emissions data report to be free of material misstatement, and whether the emissions data report is in conformance with the requirements of this article ~~or, alternatively, that~~. In the case of a qualified positive verification statement, the verification body shall explain the non-conformances contained within the emissions data report ~~contains material misstatement or otherwise does not conform with the requirements of this article~~ and why the non-conformances do not result in a material misstatement. In the case of an adverse verification statement, the verification body must explain all non-conformances and material misstatements leading to the adverse verification statement.

~~(C)~~ (D) The lead verifier in the verification team shall attest that the verification team has carried out all verification services as required by this article, and the lead verifier who has conducted the independent review of verification services and findings ~~specified in section 95131(c)(1)~~ shall attest to his or her independent review on behalf of the verification body and his or her concurrence with the verification findings.

~~(3)~~ (4) Prior to the verification body providing an adverse verification ~~opinion~~statement to the ARB, the ~~operator~~reporting entity shall be provided at least ten working days to modify the emissions data report to correct any material misstatement or nonconformance found by the verification team. The modified report and verification ~~opinion~~statement must be submitted to ARB before the applicable verification deadline, unless the ~~operator~~reporting entity makes a request to the Executive Officer as provided below in section 95131(c)(~~3~~4)(A).

(A) If the ~~operator~~reporting entity and the verification body cannot reach agreement on modifications to the emissions data report that result in a positive verification ~~opinion, the operator~~statement or qualified positive verification statement because of a disagreement on the requirements of this article, the reporting entity may petition the ARB Executive Officer to make a final decision as to the verifiability of the submitted emissions data report.

(B) If the Executive Officer determines that the emissions data report does not meet the standards and requirements specified in this article, the ~~operator~~reporting entity shall have the opportunity to submit within thirty days of the date of this decision any emissions data report revisions that address the Executive Officer's determination, for re-verification of the emissions data report. In re-verifying a revised emissions data report, the verification body and verification team shall be subject to the

requirements in section 95131(c)(1)-(2)3), and must submit the revised verification statement to ARB within 15 days.

(5) *Assigned Emissions Level.* When a reporting entity fails to receive a positive or qualified positive verification statement for a data year by the applicable deadline, the Executive Officer shall develop an assigned emissions level for the data year for the reporting entity. Within ten days of a written request by the Executive Officer, the verification body (if applicable) shall provide any available verification services information or correspondence related to the emissions data. Within ten days of a request by the Executive Officer, the reporting entity shall provide the data that is required to calculate GHG emissions for the entity according to the requirements of this article, the preliminary or final detailed verification report prepared by the verification body (if applicable), and other information requested by the Executive Officer, including the operating days and hours of the reporting entity during the data year. The reporting entity shall also make available personnel who can assist the Executive Officer's determination of an assigned emissions level for the data year.

(A) In preparing the assigned emissions level for the reporting entity, the Executive Office shall consider at a minimum the following information:

1. The number, types and days and hours of operation of the sources operated by the reporting entity for the emissions data year;
2. Any previous emissions data reports submitted by the reporting entity and verification statements rendered for those reports;
3. The potential maximum fuel and process material input and output capacities for the reporting entity's emissions sources during operating hours;
4. For electric power entities, wholesale and retail transactions that would affect an assigned emissions level, for the relevant data year and for previous years;
5. Emissions, electricity transactions, fuel use, or product output information reported to ARB or other State, federal, or local agencies.

(B) The Executive Officer shall calculate the assigned emissions level for the reporting entity using the best information available, including the information in section 95131(c)(5)(A), as applicable. The reporting entity shall be provided at least 5 days to review and comment on the assigned emissions level.

(d) Upon provision of the verification ~~opinion~~statement to ARB, the emissions data report shall be considered final ~~and no~~. No changes shall be made ~~except as provided in section 95104(d)(3). All~~to the report as submitted to ARB, notwithstanding the requirements of 40 CFR §98.3(h), and all verification

requirements of this article shall be considered complete except in the circumstance specified in section 95131(e).

(e) If the Executive Officer finds a high level of conflict of interest existed between a verification body and ~~an operator~~a reporting entity, or an emissions data report that received a positive or qualified positive verification ~~opinion~~statement fails an ARB audit, the Executive Officer may set aside the positive or qualified positive verification ~~opinion submitted~~statement issued by the verification body, and require the reporting entity to have the emissions data report re-verified by a different verification body within 90 days.

(f) Upon request by the Executive Officer the ~~operator~~reporting entity shall provide the data used to generate an emissions data report, including all data available to a verifier in the conduct of verification services, within 10 working days.

(g) Upon request of the Executive Officer the verification body shall provide ARB ~~may also review~~ the full verification report given ~~by the verification body to the operator. The full verification report shall be provided to the Executive Officer upon request~~to the reporting entity, as well as the sampling plan and any other supporting documents and calculations, within 10 working days.

~~(g)~~ (h) Upon written notification by the Executive Officer, the verification body shall make ~~itself~~its personnel available for ~~a verification services~~an ARB audit.

(i) *Verifying Biomass-derived Fuels.* Requirements for providing verification services for biomass-derived fuels not subject to a compliance obligation as set forth in title 17, California Code of Regulations, Section 95852.2 In the absence of certification of the fuel by an accredited certifier of biomass-derived fuels, the verification body shall conduct the following requirements to verify a biomass-derived fuel that will not be subject to a compliance obligation:

(1) The verification body shall provide information assessing its potential for conflict of interest as set forth in section 95133(b),(c) and (d) with the reporting entity and each biomass-derived fuel entity in the chain of custody for that fuel as part of the conflict of interest submittal requirements in 95133(e)

(2) At least one accredited verifier in the verification team, including the transactions sector specialist, shall at a minimum make one site visit, during each year full verification is required, to each biomass-derived fuel entity in the chain of custody for that fuel. One member of the verification team must visit the headquarters or other location of central data management when the biomass-derived fuel entity is a marketer, distributor, or suppler and does not physically store or produce the fuel on-site and conduct the site visit as required in section 95131(b)(4) for each biomass-derived fuel entity in the chain of custody for that fuel.

(A) The verification team members shall examine biomass-derived fuel contracts to determine that one of the two following conditions has been met:

1. That the contract for purchasing any biomass-derived fuel was in effect prior to January 1, 2010 and remains in effect or has been renegotiated for the same California operator within one year of contract expiration;
2. That the fuel being provided under a contract dated after January 1, 2010 is only for an amount of fuel that is associated with an increase in the biomass-based fuel producer's capacity.

If a contract includes both fuel that does and does not meet this condition, then only the portion of the fuel that does meet this condition will be considered biomass-derived fuel.

(B) The verification team shall determine that no entity in the chain of custody has applied for or received credit for the use of biomass-derived fuel in offset credits or any other credit for greenhouse gas reductions in another voluntary or regulatory project.

(C) The verification team shall determine that any entity that produces biomass-derived fuels is doing so in accordance with the requirements of title 17, California Code of Regulations, section 95852.2.

(D) The verification team shall determine that an entity's total volume of biomass-derived fuel transferred to all customers in a calendar year does not exceed the entity's purchases and production of biomass-derived fuels during that year.

(E) The verification team must be able to track the exact amount of fuel indentified in contracts or invoices from the producer to the reporting entity, and have reasonable assurance that the reporting entity is the only customer receiving that fuel.

(F) The verification team shall review and evaluate all fuel analytical devices and data management systems used by biomass-derived fuel entities to quantify, track, and report fuel amounts. The verification team must evaluate the uncertainty and effectiveness of these systems using the requirements in section 95131(b)(8).

(G) Verifying fuel transactions shall include evaluating the measured and estimated fuel volumes, as well as any relevant information required to calculate emissions including composition, high heat value, carbon content, or supplier specific emission factors.

(3) If any biomass-derived fuel entity in the chain of custody does not make available to the verification team all the information and documentation necessary to establish the validity of the reporting entity's claim of biomass-derived fuel purchase, the fuel purchase, as described in section 95131(i)(2)(B-G), will be considered unverifiable and be required to hold a

compliance obligation under title 17, California Code of Regulations, section 95852.1.

(4) To verify that the amount of biomass-derived fuel reported by a reporting entity is free of a material misstatement, the verification team shall determine whether there is reasonable assurance that the amount of biomass derived fuel purchased was actually produced and delivered, or injected into a transmission pipeline to the reporting entity, and any errors, omissions, or misreporting of the biofuels emissions do not result in a material misstatement. To assess conformance with this article, the verification team shall review the methods and factors used to calculate and report biomass-derived fuel amounts for adherence to the requirements of this article.

(5) Verification requirements specific to biomass-derived fuel producing facilities are as follows:

(A) The verification team shall establish that the biomass-derived fuel entity employs procedures for fuel data measurement with an accuracy within ±5 percent. All fuel analytical measurement devices shall be installed, maintained and calibrated in a manner and at a frequency required to maintain this level of accuracy. If the documentation to support this level of accuracy is not provided to the verification team, then the fuel will be considered unverifiable and be required to hold a compliance obligation under title 17, California Code of Regulations, section 95852.1.

(B) The verification team shall establish that the heating value of the biomass-derived fuel used in any transaction was appropriately calculated using the method required by section 95115(c).

(C) The verification team shall establish that the biomass-derived fuel entity retains at least 95% of its fuel production or fuel transaction data. If more than 5% of data is missing, the fuel will be considered unverifiable and be required to hold a compliance obligation under title 17, California Code of Regulations, section 95852(g).

(6) If the verification body is unable to verify the biomass-based fuel to the above requirement, it will be considered unverifiable and be required to hold a compliance obligation under title 17, California Code of Regulations, section 95852.1.

NOTE: Authority cited: Sections 39600, 39601, 39607, 39607.4, 41511, 38510, and 38530, Health and Safety Code. Reference: Sections 39600, 41511, and 38530, Health and Safety Code.

§ 95132. Accreditation Requirements for Verification Bodies, Lead Verifiers, and Verifiers of Emissions Data Reports and Offset Project Data Reports.

(a) The accreditation requirements specified in this subarticle shall apply to all verification bodies, lead verifiers, and verifiers that wish to provide verification services under this article and under the Cap-and-Trade Regulation.

(b) The Executive Officer may issue accreditation to verification bodies, lead verifiers, and verifiers that meet the requirements specified in this section.

(1) *Verification Body Accreditation Application.* To apply for accreditation as a verification body, the applicant shall submit the following information to the Executive Officer~~, except as provided in section 95132(b)(1)(F)~~.:

(A) A list of all verification staff and a description of their duties and qualifications, including ARB accredited verifiers on staff. The applicant shall demonstrate staff qualifications by listing each individual's education, experience, professional licenses, and other pertinent information.

1. A verification body shall have and retain at least two verifiers that have been accredited as lead verifiers, as specified in section 95132(b)(2);
2. A verification body shall have and retain at least five total full-time staff.

(B) The applicant shall provide a list of any judicial proceedings or administrative actions filed against the body within the previous 5 years, with an explanation as to the nature of the proceedings.

(C) The applicant shall provide documentation that the proposed verification body ~~has~~maintains a minimum of ~~one~~four million U.S. dollars of professional liability insurance and must maintain this insurance for three years after completing verification services.

(D) The applicant shall provide a demonstration that the body has policies and mechanisms in place to prevent conflicts of interest and to identify and resolve potential conflict of interest situations if they arise. The applicant shall provide the following information:

1. Identification of services provided by the verification body, the industries that the body serves, and the locations where those services are provided;
2. ~~An organization~~A detailed organizational chart that includes the verification body, its management structure, and any related entities~~.~~;

3. The verification body's internal conflict of interest policy that identifies activities and limits to monetary or non-monetary gifts that apply to all employees.

(E) The applicant shall provide a demonstration that the body has procedures or policies to support staff technical training as it relates to verification. This training shall include participating in ARB verifier training on an ongoing basis.

(F) The verification body shall notify ARB within 30 days of when it no longer meets the requirements for accreditation as a verification body in section 95132(b)(1). The verification body may request that the Executive Officer provide an additional time to hire additional staff to meet the minimum requirements of this section.

(G)~~(F)~~ If the applicant is a California air pollution control district or air quality management district, the requirements of section 95132(b)(1)(A)(2) and 95132(b)(1)(B)-(D) do not apply, except that the applicant shall provide a demonstration that the district has policies and mechanisms in place to prevent conflicts of interest and resolve potential conflict of interest situations if they arise.

(2) *Lead Verifier Accreditation Application.* To apply for accreditation as a lead verifier, the applicant shall submit documentation to the Executive Officer that provides the evidence specified in section 95132(b)(2)(A), and section 95132(b)(2)(B), or (C)~~, or (D)~~:

(A) Evidence that the applicant ~~has completed ARB verification training and received a passing score on an exit examination~~meets the criteria in 95132(b)(3); and,

~~(B) Evidence that the applicant has acted as project manager or in a lead capacity in one or more of the following greenhouse gas reporting programs:~~

~~1. As an approved lead verifier in good standing for the California Climate Action Registry prior to December 1, 2007, having performed at least three verifications by December 31, 2007; or as an acting lead verifier in the California Climate Action Registry, having taken CCAR or other GHG lead verification training and having performed at least three verifications by December 31, 2007; or,~~

~~2. As a recognized lead verifier in good standing for the United Kingdom Accreditation System, having performed at least three verifications by December 31, 2007; or,~~

~~3. In an organization accredited by a recognized agency in ISO 14065, or ISO 19011, having performed at least three verifications by December 31, 2007; or,~~

(B) ~~(C)~~ Evidence that the applicant has been an ARB accredited verifier for two continuous years and has worked as a verifier in at least three completed verifications under the supervision of an ARB accredited lead verifier, with evidence of favorable assessment by ARB for services performed; or,

(C) ~~(D)~~ Evidence that at the time of the verification training examination, the applicant has worked as a project manager or lead person for not less than four years, of which two may be graduate level work:

1. In the development of GHG or other air emissions inventories; or,
2. As a lead environmental data or financial auditor in the private sector.

(3) *Verifier Accreditation Application.* To apply for accreditation as a verifier, the applicant shall submit the following documentation to the Executive Officer:

(A) Evidence demonstrating the minimum education background required to act as a verifier for ARB. Minimum education background means that the applicant has either:

1. A bachelors level college degree or equivalent in science, technology, business, statistics, mathematics, environmental policy, economics, or financial auditing; or
2. Evidence demonstrating the completion of significant and relevant work experience or other personal development activities that have provided the applicant with the communication, technical and analytical skills necessary to conduct verification.

(B) Evidence demonstrating sufficient workplace experience to act as a verifier, including evidence that the applicant has a minimum of two years of fulltime work experience in a professional role involved in emissions data management, emissions technology, emissions ~~field enforcement~~inventories, environmental auditing, or other technical skills necessary to conduct verification.

(4) The applicant ~~shall~~must take an ARB approved general verification training course and receive a passing score ~~on an exit examination.~~of greater than an unweighted 70% on an exit examination. If the applicant does not pass the exam after the training, they may retake the exam a second time. Only one retake of the examination is allowed before the applicant is required to retake the ARB approved general verification training course. Training under the previous version of the regulation does not qualify an applicant to retake an exam under this version without first taking the training class for this revised regulation.

(5) Sector Specific and Offset Project Specific Verifiers.

(A) The applicant seeking to be accredited as a sector specific verifier as specified in section 95131(a)(2) ~~shall~~must, in addition to meeting the requirements for lead verifier or verifier qualification, have at least two years of professional experience related to the sector in which they are seeking accreditation, take ARB sector specific verification training and receive a passing score of greater than an unweighted 70% on an exit examination. If the applicant does not pass the exam after the training, they may retake the exam a second time. Only one retake of the examination is allowed before the applicant is required to retake the ARB approved general verification training course.

(B) The applicant seeking to be accredited as an offset project specific verifier as specified in title 17, California Code of Regulations, section 95977(e)(4)(A)(iii), in addition to meeting the requirements for verifier qualification, ~~take ARB sector specific~~shall meet the following requirements:

1. Be a verifier in good standing for the Climate Action Reserve prior to November 1, 2010 and have performed at least two project verifications for a project type by December 31, 2010; or
2. Have at least two years of professional experience related to developing emission inventories, conducting technical analyses, or environmental audits of the offset project type; and
3. Take ARB offset project verification training for an offset project type and receive a passing score of greater than an unweighted 70% on an exit examination. If the applicant does not pass the exam after the training, they may retake the exam a second time. Only one retake of the examination is allowed before the applicant is required to retake the ARB approved general verification training course.

(6) Nothing in this section shall be construed as preventing the Executive Officer from requesting additional information or documentation from an applicant after receipt of the application for accreditation as a verification body, lead verifier, or verifier~~;~~, or from seeking additional information from other persons or entities regarding the applicant's fitness for qualification.

(c) *ARB Accreditation.*

(1) Within 90 days of receiving an application for accreditation as a verification body, lead verifier, or verifier, the Executive Officer shall inform the applicant in writing either that the application is complete or that additional specific information is required to make the application complete.

(2) Upon a finding by the Executive Officer that an application for accreditation as a verifier or lead verifier is complete and meets all applicable regulatory requirements, the prescreening requirement is met and the applicant will be eligible to attend the verification training required by this section.

(3) Within 45 days following completion of the application process and all applicable training and examination requirements, the Executive Officer shall act to issue an Executive Order to grant or withhold accreditation for the verification body, lead verifier, or verifier.

~~(4) The Executive Officer shall issue an Executive Order to grant accreditation to the applicant if the evidence of qualification submitted by the applicant has been found complete and sufficient and the applicant has successfully completed the required training and examination(s).~~

~~(5)~~ (4) The Executive Order for accreditation is valid for a period of three years, whereupon the applicant may re-apply for accreditation as a verifier, lead verifier, or verification body if the applicant has not been subject to ARB enforcement action under this article. All ARB approved general ~~or,~~ sector specific, or offset project specific verification training and examination requirements applicable at the time of re-application must be met for accreditation to be renewed by the Executive Officer. The following requirements also apply at the time of application for re-accreditation as a lead verifier, verifier, sector specific verifier, or offset project verifier:

~~(6) The Executive Officer shall issue an Executive Order to grant accreditation to a verification body if evidence of qualification submitted by the applicant has been found to meet the~~

(A) If the applicant has not participated in at least one ARB verification by January 1, 2012, the applicant must take ARB approved GHG verification training that includes general verifier training and receive a passing score of greater than an unweighted 70% on the exit examination.

(B) If the applicant has participated in at least one ARB verification by January 1, 2012, then the applicant must take ARB approved abbreviated training that includes changes to the program since the original training was provided under 95132(b)(4), 95132(b)(5)(A), and 95132(b)(5)(B)3, and receive a passing score of greater than an unweighted 70% on the exit examination. This examination shall cover general verification and the training.

(5) All verification body requirements ~~of~~in section 95132(b)(1). must be met for the Executive Officer to renew the verification body accreditation.

~~(7)~~ (6) The Executive Officer and the applicant may mutually agree to longer time periods than those specified in subsections 95132(c)(1) or 95132(c)(3), and the applicant may submit additional supporting documentation before a decision has been made by the Executive Officer.

(7) Within 15 working days of being notified of any corrective action in another voluntary or mandatory GHG program, an ARB accredited verification body or verifier shall provide written notice to the Executive Officer of the corrective action. That notification shall include reasons for the corrective action and the type of corrective action. The verification body or verifier must provide additional information to the Executive Officer upon request.

(8) Verifiers accredited by ARB prior to January 1, 2011 shall take ARB approved training to continue to provide verification services after January 1, 2012. The training will focus on changes to the program since the original training was provided under 95132(b)(4) and 95132(b)(5)(A). The verifier must receive a passing score of greater than an unweighted 70% on the exit examination.

(d) *Modification, Suspension, or Revocation of an Executive Order Approving a Verification Body, Lead Verifier, or Verifier.* The Executive Officer may review and, for good cause, ~~modify~~including any violation of subarticle 4 of this article or any similar action in an analogous GHG system, modify, suspend, or revoke an Executive Order providing accreditation to a verification body, lead verifier, or verifier. The Executive Officer shall not revoke an Executive Order without affording the verification body, lead verifier, or verifier the opportunity for a hearing in accordance with the procedures specified in title 17, California Code of Regulations, section 60055.1 et seq.

(1) During suspension or revocation proceedings, the verification body, lead verifier, or verifier may not continue to provide verification services.
(2) Within 5 working days of suspension or revocation of accreditation, a verification body must notify all reporting entities, offset project operators, or authorized project designees for whom it is providing verification services, or has provided verification services within the past 6 months of its suspension or revocation of accreditation.
(3) A reporting entity, offset project operator, or authorized project designee who has been notified by a verification body of a suspended or revoked accreditation must contract with a new verification body for verification services.

(e) *Subcontracting.* The following requirements shall apply to any verification body that elects to subcontract a portion of verification services.

(1) All subcontractors must be accredited by ARB to perform the verification services for which the subcontractor has been engaged by the verification body.
(2) The verification body must assume full responsibility for verification services performed by subcontractor verifiers ~~or verification bodies~~.
(3) A verification body shall not use subcontractors to meet the minimum staff total or lead verifier requirements as specified in section 95132(b)(1)(A)1. and section 95132(b)(1)(A)2.
(4) ~~A verification body or~~A verifier acting as a subcontractor to another verification body shall not further subcontract or outsource verification services for ~~an operator~~a reporting entity.
(5) A verification body that engages a subcontractor shall be responsible for demonstrating an acceptable level of conflict of interest, as provided in section 95133, between its subcontractor and the ~~operator~~reporting entity for which it will provide verification services.

(6) A verification body may not use a subcontractor as the independent reviewer.

NOTE: Authority cited: Sections 39600, 39601, 39607, 39607.4, 41511, 38510, and 38530, Health and Safety Code. Reference: Sections 39600, 41511, and 38530, Health and Safety Code.

§ 95133. Conflict of Interest Requirements for Verification Bodies for Emissions Data Reports.

(a) The conflict of interest provisions of this section shall apply to verification bodies, lead verifiers, and verifiers accredited by ARB to perform verification services for reporting entities.

(b) The potential for a conflict of interest ~~shall~~must be deemed to be high where:

(1) The verification body and ~~operator~~reporting entity share any management staff or board of directors membership, or any of the senior management staff of the ~~operator~~reporting entity have been employed by the verification body, or vice versa, within the previous three years; or

(2) Within the previous five~~three~~ years, any staff member of the verification body or any related entity has provided to the ~~operator~~reporting entity any of the following non-verification services:

(A) Designing, developing, implementing, reviewing, or maintaining an inventory or information or data management system for facility ~~greenhouse gases~~air emissions, or, where applicable, electricity or fuel transactions, unless the review was part of providing greenhouse gas verification services;

(B) Developing greenhouse gas emission factors or other greenhouse gas-related engineering analysis, including developing or reviewing a California Environmental Quality Act (CEQA) greenhouse gas analysis that includes facility specific information;

(C) Designing energy efficiency, renewable power, or other projects which explicitly identify greenhouse gas reductions as a benefit;

(D) Designing, developing, implementing, conducting an internal audit, consulting, or maintaining a GHG emissions reduction or GHG removal offset project as defined in the Cap-and-Trade Regulation;

(E) Owning, buying, selling, trading, or retiring shares, stocks, or emissions reduction credits from an offset project that was developed by or resulting reduction credits are owned by the reporting entity;

(F) Dealing in or being a promoter of credits on behalf of an offset project operator or authorized project designee where the credits are owned by or the offset project was developed by the reporting entity;

~~(D)~~ (G) Preparing or producing greenhouse gas-related manuals, handbooks, or procedures specifically for the reporting ~~facility~~entity;

~~(E)~~ (H) Appraisal services of carbon or greenhouse gas liabilities or assets;

~~(F)~~ (I) Brokering in, advising on, or assisting in any way in carbon or greenhouse gas-related markets;

~~(G) Managing~~(J) Directly managing any health, environment or safety functions for the reporting entity;

~~(H)~~ (K) Bookkeeping or other services related to ~~the~~ accounting records or financial statements;

~~(I)~~ (L) Any service related to information systems, including ISO 14001 certification, unless those systems will not be part of the verification process;

~~(J)~~ (M) Appraisal and valuation services, both tangible and intangible;

~~(K)~~ (N) Fairness opinions and contribution-in-kind reports in which the verification body has provided its opinion on the adequacy of consideration in a transaction, unless the resulting services ~~shall~~will not be part of the verification process;

~~(L)~~ (O) Any actuarially oriented advisory service involving the determination of amounts recorded in financial statements and related accounts;

~~(M)~~ (P) Any internal audit service that has been outsourced by the reporting entity or offset project operator that relates to the ~~operator~~reporting entity's internal accounting controls, financial systems or financial statements, unless the result of those services ~~shall~~will not be part of the verification process;

~~(N)~~ (Q) Acting as a broker-dealer (registered or unregistered), promoter or underwriter on behalf of the ~~operator~~reporting entity;

~~(O)~~ (R) Any legal services;

~~(P)~~ (S) Expert services to the ~~operator~~reporting entity or ~~its~~a legal representative for the purpose of advocating the ~~operator~~reporting entity's interests in litigation or in a regulatory or administrative proceeding or investigation~~, unless providing factual testimony~~.

"Member" for the purposes of this section means any employee or subcontractor of the verification body or related entities of the verification body. "Member" also includes any individual with majority equity share in the verification body or its related entities. "Related entity" for the purposes of this section means any direct parent company, direct subsidiary, or sister company.

(3) The potential for conflict of interest shall be deemed to be high when any staff member of the verification body provides any type of non-monetary incentive to a reporting entity to secure a verification services contract.

~~(3)~~ (4) The potential for a conflict of interest shall also be deemed to be high where any staff member of the verification body has provided verification services for the ~~operator within the last three years,~~reporting entity except within the time periods in which the ~~operator~~reporting entity is allowed to use the same verification body as specified in sections 95130(a) ~~and 95130(b)~~.

(c) The potential for a conflict of interest shall be deemed to be low where no potential for a conflict of interest is found under section 95133(b) and any non-verification services provided by any member of the verification body to the ~~operator~~reporting entity within the last three years are valued at less than 20 percent of the fee for the proposed verification.

(d) The potential for a conflict of interest shall be deemed to be medium where the potential for a conflict of interest is not deemed to be either high or low as specified in sections 95133(b) and 95133(c). The potential for conflict of interest will also be deemed to be medium where there are any instances of personal or familial relationships between the members of the verification body and management or staff of the reporting entity.

(1) If a verification body identifies a medium potential for conflict of interest and ~~wishes~~intends to provide verification services for the ~~operator~~reporting entity, the verification body shall submit, in addition to the submittal requirements specified in section 95133(e), a plan to avoid, neutralize, or mitigate the potential conflict of interest situation. At a minimum, the conflict of interest mitigation plan shall include:

(A) A demonstration that any individuals with potential conflicts have been removed and insulated from the project.

(B) An explanation of any changes to the organizational structure or verification body to remove the potential conflict of interest. A demonstration that any unit with potential conflicts has been divested or moved into an independent entity or any subcontractor with potential conflicts has been removed.

(C) Any other circumstance that specifically addresses other sources for potential conflict of interest.

(2) As provided in section 95133(f)(4), the Executive Officer shall evaluate the conflict of interest mitigation plan and determine whether verification services may proceed.

(e) *Conflict of Interest Submittal Requirements for Accredited Verification Bodies.*

(1) Before the start of any work related to providing verification services to ~~an operator~~a reporting entity, a verification body must first be authorized in writing by the Executive Officer to provide verification services. To obtain authorization the verification body shall submit to the Executive Officer a self-evaluation of the potential for any conflict of interest that the body, its partners, or any subcontractors performing verification services may have with the ~~operator~~reporting entity for which it will perform verification services. The submittal shall include the following:

(A) Identification of whether the potential for conflict of interest is high, low, or medium based on factors specified in sections 95133(b), (c), and (d);

~~(B) An organizational chart of the verification body and brief description of the verification body and any related entities;~~

~~(C)~~ (B) Identification of whether the verification body or any member of the verification team has previously provided verification services for the ~~operator~~reporting entity and, if so, the years in which such verification services were provided;

~~(D)~~ (C) Identification of whether any member of the verification team or related entity has engaged in any non-verification services of any nature with the ~~operator~~reporting entity either within or outside California during the previous three years. If non-verification services have previously been provided, the following information shall also be submitted:

1. Identification of the nature and location of the work performed for the ~~operator~~reporting entity and whether the work is similar to the type of work to be performed during verification, such as emissions inventory, auditing, energy efficiency, renewable energy, or other work with implications for the ~~operator~~reporting entity's greenhouse gas emissions or the accounting of greenhouse gas emissions or electricity or fuel transactions;
2. The nature of past, present or future relationships with the ~~operator~~reporting entity including:

    a. Instances when any member of the verification team has performed or intends to perform work for the ~~operator~~reporting entity;
    b. Identification of whether work is currently being performed for the ~~operator~~reporting entity, and if so, the nature of the work;
    c. How much work was performed for the ~~operator~~reporting entity in the last three years, in dollars ~~or percentage of verifier's revenues or gross income~~;
    d. Whether any member of the verification team has any contracts or other arrangements to perform work for the ~~operator~~reporting entity or a related entity;
    e. How much work related to greenhouse gases or electricity transactions the verification team has performed for the ~~operator~~reporting entity or related entities in the last three years, in dollars ~~or percentage of the body's and its subcontractors' revenues or gross income~~.

3. Explanation of how the amount and nature of work previously performed is such that any member of the verification team's credibility and lack of bias should not be under question.

~~(E)~~ (D) A list of names of the staff that would perform verification services for the ~~operator~~reporting entity, and a description of any instances of personal or family relationships with management or employees of the ~~operator~~reporting entity that potentially represent a conflict of interest; and,

~~(F)~~ (E) Identification of any other circumstances known to the verification body, or ~~operator~~reporting entity that could result in a conflict of interest.

(F) Attest, in writing, to ARB as follows:

"I certify under penalty of perjury of the laws of California the information provided in the Conflict of Interest submittal is true, accurate, and complete."

(f) *Conflict of Interest Determinations.* The Executive Officer ~~shall~~must review the self-evaluation submitted by the verification body and determine whether the verification body is authorized to perform verification services for the ~~operator~~reporting entity.

(1) The Executive Officer shall notify the verification body in writing when the conflict of interest evaluation information submitted under section 95132(e) is deemed complete. Within ~~forty-five~~30 working days of deeming the ~~evaluation~~ information complete, the Executive Officer shall determine whether the verification body is authorized to proceed with verification and ~~shall~~must so notify the verification body.

(2) If the Executive Officer determines the verification body or any member of the verification team meets the criteria specified in section 95133(b), the Executive Officer shall find a high potential conflict of interest and verification services may not proceed.

(3) If the Executive Officer determines that there is a low potential conflict of interest, verification services may proceed.

(4) If the Executive Officer determines that the verification body and verification team have a medium potential for a conflict of interest, the Executive Officer shall evaluate the conflict of interest mitigation plan submitted pursuant to sections 95133(d), and may request additional information from the applicant to complete the determination. In determining whether verification services may proceed, the Executive Officer may consider factors including, but not limited to, the nature of previous work performed, the current and past relationships between the verification body and its subcontractors with the ~~operator~~reporting entity, and the cost of the verification services to be performed. If the Executive Officer determines that these factors when considered in combination demonstrate an acceptable level of potential conflict of interest, ~~then~~ the Executive Officer will authorize the verification body to provide verification services.

(g) *Monitoring Conflict of Interest Situations.*

(1) After commencement of verification services, the verification body shall monitor and immediately make full disclosure in writing to the Executive Officer regarding any potential for a conflict of interest situation that arises. This disclosure shall include a description of actions that the verification body has taken or proposes to take to avoid, neutralize, or mitigate the potential for a conflict of interest.

(2) The verification body shall continue to monitor arrangements or relationships that may be present for a period of one year after the completion of verification services. During that period, within 30 days of the verification body or any verification team member entering into any contract with the ~~operator~~reporting entity for which the body has provided verification services, the ~~verifier~~verification body shall notify the Executive Officer of the contract and the nature of the work to be performed. The Executive Officer, within 30 working days, will determine the level or conflict using the criteria in section 95133(a)-(d), if the reporting entity must reverify their emissions data report, and if accreditation revocation is warranted.

(3) The verification body shall notify the Executive Office, within 30 days, of any emerging conflicts of interest during the time verification services are being provided.

(A) If the Executive Officer determines that a disclosed emerging potential conflict is medium risk and this risk can be mitigated, the verification body is deemed to have met the conflict of interest requirements to continue to provide verification services to the reporting entity and will not be subject to suspension or revocation of accreditation as specified in section 95132(d).

(B) If the Executive Officer determines that a disclosed emerging potential conflict is medium or high risk and this risk cannot be mitigated, the verification body will not be able to continue to provide verification services to the reporting entity, and may be subject to suspension or revocation of accreditation under section 95132(d).

~~(3)~~ (4) The verification body shall report to the Executive Officer any changes in its organizational structure, including mergers, acquisitions, or divestitures, for one year after completion of verification services.

~~(4)~~ (5) The Executive Officer may invalidate a verification finding if a potential conflict of interest has arisen for any member of the verification team. In such a case, the ~~operator~~reporting entity shall be provided ~~180~~90 days to complete re-verification.

~~(5)~~ (6) If the verification body or its subcontractor(s) are found to have violated the conflict of interest requirements of this article, the Executive Officer may rescind accreditation of the body, its verifier staff, or its subcontractor(s) as provided in section 95132(d).

NOTE: Authority cited: Sections 39600, 39601, 39607, 39607.4, 41511, 38510, and 38530, Health and Safety Code. Reference: Sections 39600, 41511, and 38530, Health and Safety Code.

Subarticle 5. Reporting Requirements and Calculation Methods for Petroleum and Natural Gas Systems.

§ 95150. Definition of the Source Category.

(a) This source category consists of the following:

(1) *Offshore petroleum and natural gas production.* Offshore petroleum and natural gas production is any platform structure, affixed temporarily or permanently to offshore submerged lands, that houses equipment to extract hydrocarbons from the ocean or lake floor and that transfers such hydrocarbons to storage, transport vessels, or onshore. In addition, offshore production includes secondary platform structures and storage tanks associated with the platform structure.

(2) *Onshore petroleum and natural gas production.* Onshore petroleum and natural gas production equipment means all structures associated with wells (including compressors, generators, or storage facilities), piping (including flowlines or intra-facility gathering lines), and portable non-self-propelled equipment (including well drilling and completion equipment, workover equipment, gravity separation equipment, auxiliary non-transportation-related equipment, and leased, rented or contracted equipment) used in the production, extraction, recovery, lifting, stabilization, separation or treating of petroleum and/or natural gas (including condensate). This also includes associated storage or measurement and all systems engaged in gathering produced gas from multiple wells, all enhanced oil recovery (EOR) operations using CO_2 and thermal energy, and all petroleum and natural gas production located on islands, artificial islands or structures connected by a causeway to land, an island, or artificial island.

(3) *Onshore natural gas processing plants.* Natural gas processing plants are designed to separate and recover natural gas liquids (NGLs) or other non-methane gases and liquids from a stream of produced natural gas to meet onshore natural gas transmission pipeline quality specifications through equipment performing one or more of the following processes: oil and condensate removal, water removal, separation of natural gas liquids, sulfur and carbon dioxide removal, fractionation of NGLs, or other processes, and also the capture of CO_2 separated from natural gas streams for delivery outside the facility. In addition, field gathering and/or boosting stations that gather and process natural gas from multiple wellheads, and compress and transport natural gas (including flowlines or intra-facility gathering lines or compressors) as feed to the natural gas processing plants are considered a part of the processing plant. Gathering and boosting stations that send the natural gas to an onshore natural gas transmission compression facility, or natural gas distribution facility, or to an end user are considered stand alone natural gas processing facilities. All residue gas compression equipment operated by a processing plant, whether inside or outside the processing plant fence, are considered part of the natural gas processing plant.

(4) *Onshore natural gas transmission compression.* Onshore natural gas transmission compression means any fixed combination of compressors that move natural gas at elevated pressure from production fields or natural gas processing facilities, in transmission pipelines, to natural gas distribution pipelines, or into storage. In addition, a transmission compressor station includes equipment for liquids separation, natural gas dehydration, and tanks for the storage of water and hydrocarbon liquids.

(5) *Underground natural gas storage.* Underground natural gas storage means subsurface storage, including depleted gas or oil reservoirs and salt dome caverns utilized for storing natural gas that has been transferred from its original location for the primary purpose of load balancing (the process of equalizing the receipt and delivery of natural gas); natural gas underground storage processes and operations (including compression, dehydration and flow measurement); and all the wellheads connected to the compression units located at the facility.

(6) *Liquefied natural gas (LNG) storage.* LNG storage means onshore LNG storage vessels located above ground, equipment for liquefying natural gas, compressors to capture and re-liquefy boil-off-gas, re-condensers, and vaporization units for re-gasification of the liquefied natural gas.

(7) *LNG import and export equipment.* LNG import equipment means all onshore or offshore equipment that receives imported LNG via ocean transport, stores LNG, re-gasifies LNG, and delivers re-gasified natural gas to a natural gas transmission or distribution system. LNG export equipment means all onshore or offshore equipment that receives natural gas, liquefies natural gas, stores LNG, and transfers the LNG via ocean transportation to any location, including locations in the United States.

(8) *Natural Gas Distribution.* Natural gas distribution means distribution pipelines (not interstate pipelines or intrastate pipelines) and metering and regulating stations that physically deliver natural gas to end users.

NOTE: Authority cited: Sections 39600, 39601, 39607, 39607.4, 41511, 38510, and 38530, Health and Safety Code. Reference: Sections 39600, 41511, and 38530, Health and Safety Code.

§ 95151. Reporting Threshold and Reporting Entity.

(a) The operator of a facility in section 95150 who is required to report under section 95101 of this article, and who is not eligible for abbreviated reporting under section 95103(a), must comply with this subarticle in reporting GHG emissions from petroleum and natural gas systems to ARB.

(1) For the purposes of reporting for onshore petroleum and natural gas production, the operator is the operating entity listed on the state well drilling permit, or the state operating permit for wells where no drilling permit is issued by the state, who operates onshore petroleum and natural gas production wells and controls by means of ownership (including leased and rented) and

operation (including contracted) stationary and portable equipment located on all well pads within a single hydrocarbon basin as defined by the American Association of Petroleum Geologists (AAPG) three-digit Geological Province Code (published 1991). Where more than one entity holds the state well drilling permit, or well operating permit where no well drilling permit is issued by the state, the permitted entities for the facility must designate one entity to report all emissions from the jointly controlled facility. Where an operating entity holds more than one permit to operate wells in a basin, then all onshore petroleum and natural gas production well permits in their name in the basin, including all equipment on well pads, would be considered one onshore petroleum and natural gas production facility for the purposes of reporting under this article.

(b) In determining whether a facility in section 95150 meets the reporting threshold defined in section 95101(e), the operator must include combustion emissions from portable equipment that cannot move on roadways under its own power and drive train and that is stationed at a wellhead, including drilling rigs, dehydrators, compressors, electrical generators, steam boilers, and heaters.

NOTE: Authority cited: Sections 39600, 39601, 39607, 39607.4, 41511, 38510, and 38530, Health and Safety Code. Reference: Sections 39600, 41511, and 38530, Health and Safety Code.

§ 95152. GHGs to Report.

(a) The operator must monitor, calculate and report CO_2, CH_4, and N_2O emissions as applicable from each source type specified in paragraphs (b) through (i) of this section, according to the requirements of sections 95153 through 95156.

(b) For offshore petroleum and natural gas production, the operator must report emissions from all "stationary fugitive" and "stationary vented" sources as identified in the Minerals Management Service (MMS) Gulfwide Offshore Activity Data System (GOADS) study (2005 Gulfwide Emission Inventory Study MMS 2007-067).

(c) For onshore petroleum and natural gas production, the operator must report emissions from the following source types:

(1) Natural gas pneumatic high bleed device venting.
(2) Natural gas pneumatic low bleed device venting.
(3) Natural gas driven pneumatic pump venting.
(4) Well venting for liquids unloading.
(5) Gas well venting during conventional well completions.
(6) Gas well venting during unconventional well completions.
(7) Gas well venting during conventional well workovers.
(8) Gas well venting during unconventional well workovers.
(9) Gathering pipeline fugitives.
(10) Storage tanks.

(11) Reciprocating compressor rod packing venting.
(12) Well testing venting and flaring.
(13) Associated gas venting and flaring.
(14) Dehydrator vent stacks.
(15) Coal bed methane produced water emissions.
(16) EOR injection pump blowdown.
(17) Acid gas removal vent stacks.
(18) Centrifugal compressor wet seal degassing venting.
(19) Produced water dissolved CO_2.
(20) Fugitive emissions from valves, connectors, open ended lines, pressure relief valves, compressor starter gas vents, pumps, flanges, and other fugitive sources (such as instruments, loading arms, pressure relief valves, stuffing boxes, compressor seals, dump lever arms, and breather caps for crude services).

(d) For onshore natural gas processing, the operator must report emissions from the following sources:

(1) Reciprocating compressor rod packing venting.
(2) Centrifugal compressor wet seal degassing venting.
(3) Storage tanks.
(4) Blowdown vent stacks.
(5) Dehydrator vent stacks.
(6) Acid gas removal vent stacks.
(7) Flare stacks.
(8) Gathering pipeline fugitives.
(9) Fugitive emissions from: valves, connectors, open ended lines, pressure relief valves, meters, and centrifugal compressor dry seals.

(e) For onshore natural gas transmission compression, the operator must report emissions from the following sources:

(1) Reciprocating compressor rod packing venting.
(2) Centrifugal compressor wet seal degassing venting.
(3) Blowdown vent stacks.
(4) Natural gas pneumatic high bleed device venting.
(5) Natural gas pneumatic low bleed device venting.
(6) Fugitive emissions from connectors, block valves, control valves, compressor blowdown valves, pressure relief valves, orifice meters, other meters, regulators, and open ended lines.

(f) For underground natural gas storage, the operator must report emissions from the following sources:

(1) Reciprocating compressor rod packing venting.
(2) Centrifugal compressor wet seal degassing venting.

(3) Natural gas pneumatic high bleed device venting.
(4) Natural gas pneumatic low bleed device venting.
(5) Fugitive emissions from connectors, block valves, control valves, compressor blowdown valves, pressure relief valves, orifice meters, other meters, regulators, and open ended lines.

(g) For LNG storage, the operator must report emissions from the following sources:

(1) Reciprocating compressor rod packing venting.
(2) Centrifugal compressor wet seal degassing venting.
(3) Fugitive emissions from valves, pump seals, connectors, vapor recovery compressors, and other fugitive sources.

(h) For LNG import and export equipment, the operator must report emissions from the following sources:

(1) Reciprocating compressor rod packing venting.
(2) Centrifugal compressor wet seal degassing venting.
(3) Blowdown vent stacks.
(4) Fugitive emissions from valves, pump seals, connectors, vapor recovery compressors, and other fugitive sources.

(i) For natural gas distribution, the operator must report emissions from the following sources:

(1) Above ground meter regulators and gate station fugitive emissions from connectors, block valves, control valves, pressure relief valves, orifice meters, other meters, regulators, and open ended lines.
(2) Below ground meter regulators and vault fugitives.
(3) Pipeline main fugitives.
(4) Service line fugitives.

(j) The operator must report the CO_2, CH_4, and N_2O emissions from each flare.

(k) The operator must report emissions of CO_2, CH_4, and N_2O from each stationary fuel combustion unit by following the requirements of section 95115 of this article.

(l) The operator must report CO_2 emissions captured and transferred off site by following the requirements of section 95123 of this article.

NOTE: Authority cited: Sections 39600, 39601, 39607, 39607.4, 41511, 38510, and 38530; Health and Safety Code. Reference: Sections 39600, 41511, and 38530, Health and Safety Code.

§ 95153. Calculating GHG Emissions.

(a) Natural Gas Pneumatic High Bleed Device and Pneumatic Pump Venting. The operator must calculate emissions from natural gas high bleed flow control device venting using the applicable method below:

(1) Method 1: The operator must calculate vented CH_4 and CO_2 emissions using manufacturer data. The operator may use this method through reporting year 2013 when metering of natural gas consumption in all high bleed devices and pneumatic pumps is required. By January 1, 2013 natural gas consumption must be metered for 50 percent of the operator's pneumatic high bleed devices and pneumatic pumps, and the operator must use Method 2 in section 95153(a)(3) for these metered devices and pumps. The operator may use Method 1 to calculate emissions from all unmetered devices and pumps in 2013. By January 1, 2014, the operator must meter natural gas consumption for all pneumatic high bleed devices and pneumatic pumps, and use Method 2 in section 95153(a)(3) to calculate emissions.

(2) The operator must calculate natural gas emissions for all unmetered high bleed devices and pneumatic pumps using the following equation:

$$E_{nm} = \sum_{d/p=1}^{n} B_{d/p} * T$$

Where:

E_{nm} = Annual natural gas emissions at standard conditions, in cubic feet for all pneumatic high bleed devices and pumps where natural gas consumption is not metered.

n = Total number of un-metered high bleed devices and pumps.

$B_{d/p}$ = Natural gas driven pneumatic device or pump emissions rate at standard conditions in cubic feet per minute, as provided by the manufacturer.

T = Amount of time in minutes that the pneumatic device or pump has been operational through the reporting period.

(3) Method 2: The operator must calculate vented emissions for all metered pneumatic high bleed devices and pneumatic pumps using the following equation:

$$E_m = \sum_{1}^{n} B_n$$

Where:

E_m = Annual natural gas emissions at standard conditions, in cubic feet for all pneumatic high bleed devices and pneumatic pumps where gas is metered.

n = Total number of meters
B_n = Natural gas consumption for meter n.

(4) For both Method 1 and Method 2 of this paragraph, CH_4 and CO_2 volumetric and mass emissions must be calculated from volumetric natural gas emissions using calculations in paragraphs (s) and (t) of this section.

(b) *Natural Gas Pneumatic Low Bleed Device Venting.* The operator must calculate CH_4 and CO_2 emissions from natural gas pneumatic low bleed devices using the following equation:

$$E_{LB} = \sum_{LB=1}^{n} B_{LB} * T$$

Where:
E_{LB} = Annual natural gas emissions at standard conditions, in cubic feet for all pneumatic low bleed devices where natural gas consumption is not metered.
n = Total number of low bleed devices
B_{LB} = Natural gas driven low bleed pneumatic device emissions rate at standard conditions in cubic feet per minute, as provided by the manufacturer.
T = Amount of time in minutes that the pneumatic low bleed device has been operational during the reporting period.

(1) CH_4 and CO_2 volumetric and mass emissions must be calculated from volumetric natural gas emissions using calculations in paragraphs (s) and (t) of this section.

(c) *Acid Gas Removal (AGR) Vent Stacks.* For AGR (including processes such as amine, membrane, molecular sieve or other absorbents and adsorbents), the operator must calculate emissions for CO_2 using the following equation:

$$E_{a,CO2} = (V_1 * \%Vol_1) - (V_2 * \%Vol_2)$$

Where:
$E_{a,CO2}$ = Annual volumetric CO_2 emissions at ambient condition, in cubic feet per year.
V_1 = Metered total annual volume of natural gas flow into AGR unit in cubic feet per year at ambient condition.
$\%Vol_1$ = Volume weighted CO_2 content of natural gas into the AGR unit.
V_2 = Metered total annual volume of natural gas flow out of the AGR unit in cubic feet per year at ambient condition.
$\%Vol_2$ = Volume weighted CO_2 content of natural gas out of the AGR unit.

(1) If a continuous gas analyzer is installed, then the continuous gas analyzer

results must be used. If a continuous gas analyzer is not available, quarterly gas samples must be taken to determine $\%Vol_1$ and $\%Vol_2$ according to methods set forth in section 95154(a)(2) of this article.

(2) If AGR vent stack emissions are captured and re-injected into the oil/gas field, operators are exempt from reporting AGR vent stack emissions.

(3) The operator must calculate CO_2 volumetric emissions at standard conditions using calculations in paragraph (r) of this section.

(4) Mass CO_2 emissions must be calculated from volumetric CO_2 emissions using calculations in paragraphs (s) and (t) of this section.

(d) *Dehydrator Vent Stacks.* For dehydrator vent stacks without vapor recovery or thermal control devices, the operator must calculate annual mass CH_4 and CO_2 emissions at standard temperature and pressure (STP) conditions using the simulation software package GRI-GLYCalc Version 4.0 (published 2008).

(1) A minimum of the following parameters must be used for characterizing emissions from dehydrators:

(A) Feed natural gas flow rate.
(B) Feed natural gas water content.
(C) Outlet natural gas water content.
(D) Absorbent circulation pump type (natural gas pneumatic/ air pneumatic/ electric).
(E) Absorbent circulation rate.
(F) Absorbent type: including triethylene glycol (TEG), diethylene glycol (DEG) or ethylene glycol (EG).
(G) Use of stripping natural gas.
(H) Use of flash tank separator (and disposition of recovered gas).
(I) Hours operated.
(J) Wet natural gas temperature, pressure, and composition.

(2) The operator must calculate annual emissions from dehydrator vent stacks to flares or regenerator fire-box/fire tubes as follows:

(A) The operator must use the dehydrator vent stack volume and gas composition as determined in paragraph (e)(1) of this section.
(B) The operator must use the calculation methodology of flare stacks in paragraph (l) of this section to determine dehydrator vent stack emissions from the flare or regenerator combustion gas vent.

(3) Operators of dehydrators that use desiccant must calculate emissions from the amount of gas vented from the vessel every time it is depressurized for the desiccant refilling process using the following equation:

$$E_{s,n} = \sum_{1}^{n} \left(H * D^2 * \pi * P_2 * \%G\right)/\left(4 * P_1 * 1{,}000 cf/Mcf\right)$$

Where:

$E_{s,n}$ = Annual natural gas emissions at standard conditions (Mcf).
n = number of desiccant refillings during reporting period
H = Height of the dehydrator vessel (ft).
D = Inside diameter of the vessel (ft).
P_1 = Atmospheric pressure (psia) default = 14.7 psia.
P_2 = Pressure of the gas (psia).
π = pi (3.1416).
%G = Percent of packed vessel volume that is gas.

(A) Both CH_4 and CO_2 volumetric and mass emissions must be calculated from volumetric natural gas emissions using calculations in paragraphs (s) and (t) of this section.

(e) *Well Venting For Liquids Unloadings*

(1) The operator must calculate emissions from each well venting for liquids unloading using the following equation:

$$E_{s,n} = \left\{\left(0.371 * 10^{-3}\right) * CD^2 * WD * SP * V\right\} + \left\{SFR * HR\right\}$$

Where:

$E_{s,n}$ = Annual natural gas emissions at standard conditions, in cubic feet/year.
$0.371 * 10^{-3}$ = {pi(3.1416)/4}/{(14.7*144) psia converted to pounds per square feet}
CD = Casing diameter (inches).
WD = Well depth (feet).
SP = Shut-in pressure (psig).
V = Number of vents per year.
SFR = Sales flow rate of gas well in cubic feet per hour immediately prior to the venting event.
HR = Hours that the well was left open to the atmosphere during unloading.

(2) Both CH_4 and CO_2 volumetric and mass emissions must be calculated from volumetric natural gas emissions using calculations in paragraphs (s) and (t) of this section.

(f) *Gas Well Venting During Unconventional Well Completions and Workovers.*

(1) The operator must calculate emissions from unconventional gas well venting during well completions and workovers from hydraulic fracturing using the following equation:

$E_{a,n} = T * FR$

Where:
$E_{a,n}$ = Annual natural gas vented emissions at ambient conditions in cubic feet.
T = Cumulative amount of time in hours of well venting during the year.
FR = Gas Flow Rate in cubic feet per hour, under ambient conditions, as required in paragraph (f)(1) of this section.

(2) The operator must calculate natural gas volumetric emissions at standard conditions using calculations in paragraph (r) of this section.

(3) Both CH_4 and CO_2 volumetric and mass emissions must be calculated from volumetric natural gas emissions using calculations in paragraphs (s) and (t) of this section.

(4) The flow rate for gas well venting during well completions and workovers from hydraulic fracturing must be determined using either of the calculation methodologies described in subparagraphs (A) and (B) below. The same calculation methodology must be used for the entire reporting year.

(A) Calculation Methodology 1. For one well completion in each gas producing field and for one well workover in each gas producing field, a recording flow meter must be installed on the vent line during each well unloading event according to methods set forth in section 95154(a)(2) of this article.

1. The average flow rate in cubic feet per minute of venting must be calculated for one well completion in each field and for one well workover in each field.
2. The respective flow rates must be applied to all well completions in the field and to all well workovers in the field, multiplied by the number of minutes of venting of all well completions and workovers, respectively, in that field.
3. New flow rates for completions and workovers must be calculated every other year for each reporting field and horizon.

(B) Calculation Methodology 2. For one well completion in each gas producing field and for one well workover in each gas producing field, the operator must record the pressures measured before and after the well choke according to methods set forth in section 95154(a)(2) of this article.

1. The average flow rate in cubic feet per minute of venting across the choke must be calculated for one well completion in each field and for one well workover in each field.
2. The respective flow rates must be applied to all well completions in

the field and to all well workovers in the field, multiplied by the number of minutes of venting of all well completions and workovers in that field.

3. New flow rates for completions and workovers must be calculated every other year for each reporting field and horizon.

(C) The operator must calculate natural gas volumetric emissions at standard conditions using calculations in paragraph (r) of this section.

(D) Both CH_4 and CO_2 volumetric and mass emissions must be calculated from volumetric natural gas emissions using calculations in paragraphs (s) and (t) of this section.

(E) The operator must calculate annual emissions from gas well venting during well completions and workovers to flares as follows:

1. The operator must use the gas well venting volume during well completions and workovers as determined in paragraph (f)(4) of this section.
2. The operator must use the calculation methodology of flare stacks in paragraph (l) of this section to determine gas well venting during well completions and workovers emissions from the flare.

(g) *Gas Well Venting During Conventional Well Completions and Workovers.* The operator must calculate emissions from each gas well venting during conventional well completions and workovers using the following equation:

$$E_{a,n} = \sum_{1}^{n} V * T$$

Where:

$E_{a,n}$ = Annual emissions in cubic feet at ambient conditions from gas well ventings during conventional well completions or workovers.

n = number of venting events per reporting period.

V = Daily gas production rate in cubic feet per minute immediately prior to venting event.

T = Cumulative amount of time of well venting in minutes during venting event.

(1) The operator must calculate natural gas volumetric emissions at standard conditions using calculations in paragraph (r) of this section.

(2) Both CH_4 and CO_2 volumetric and mass emissions must be calculated from volumetric natural gas emissions using calculations in paragraphs (s) and (t) of this section.

(h) *Blowdown Vent Stacks.* The operator must calculate blowdown vent stack emissions as follows:

(1) The operator must calculate the total volume (including from pipelines, compressor case or cylinders, manifolds, suction and discharge bottles and

vessels) between isolation valves.

(2) The operator must retain logs of the number of blowdowns for each equipment type according to the recordkeeping requirements of section 95105 of this article.

(3) The operator must calculate the total annual venting emissions using the following equation:

$$E_{a,n} = N * V_v$$

Where:

$E_{a,n}$ = Annual natural gas venting emissions at ambient conditions from blowdowns in cubic feet.

N = Number of blowdowns for the equipment in reporting year.

V_v = Total volume of blowdown equipment chambers (including pipelines, compressors and vessels) between isolation valves in cubic feet.

(4) The operator must calculate natural gas volumetric emissions at standard conditions using calculations in paragraph (r) of this section.

(5) The operator must calculate both CH_4 and CO_2 volumetric and mass emissions from volumetric natural gas emissions using calculations in paragraphs (s) and (t) of this section.

(i) *Onshore Production and Processing Storage Tanks.* For emissions from atmospheric pressure storage tanks receiving produced liquids from onshore petroleum and natural gas production facilities (including stationary liquid storage not owned or operated by the reporter) and onshore natural gas processing facilities, the operator must calculate annual CH_4 and CO_2 emissions using the appropriate method below. For storage tank batteries where the oil production rate is 10 barrels per day or less the operator must use Method 1. For storage tank batteries where the oil production rate is greater than 10 barrels per day the operator must use Method 2.

(1) Method 1: The operator must use this method for storage tank batteries where the oil production rate is 10 barrels per day or less. The operator must use E&P Tank Version 2.0 to calculate CH_4 and CO_2 emissions.

(A) A minimum of the following parameters must be used to characterize emissions from liquid transfer to atmospheric pressure storage tanks.

1. Separator oil composition.
2. Separator temperature.
3. Separator pressure.
4. Sales oil API gravity.
5. Sales oil production rate.
6. Sales oil Reid vapor pressure.
7. Ambient air temperature.

8. Ambient air pressure.

(B) The operator must determine if the storage tank has vapor recovery or thermal control devices.

1. The operator must adjust the emissions estimated using E&P Tank downward by the magnitude of emissions captured using a vapor recovery system for beneficial use.

(C) The operator must calculate emissions from liquids sent to atmospheric storage tanks vented to flares as follows:

1. The operator must use the storage tank emissions volume and gas composition as determined in this section.
2. The operator must use the calculation methodology of flare stacks in paragraph (I) of this section to determine storage tank emissions from the flare.

(D) If liquids are sent to atmospheric storage tanks where the tank emissions are not represented by the equilibrium conditions of the liquid in a gas-liquid separator and calculated by E&P Tank, then emissions must be calculated as follows:

1. The operator must use the storage tank emissions as determined in this section.
2. The operator must multiply the emissions by 3.87 for sales oil less than 45 API gravity.
3. The operator must multiply the emissions by 5.37 for sales oil equal to or greater than 45 API gravity.

(2) Method 2: The operator must use the following method for storage tanks where the oil production rate is greater than 10 barrels per day.

(A) The operator must annually determine the Gas-Oil Ratio (GOR) of produced liquids (crude and condensate) for each storage tank. An additional sample must be collected, analyzed and emissions calculated when one or more producing wells are connected to or disconnected from the storage tank. Measurements are limited to land-based storage tanks containing condensate and crude oil.

1. A pressurized sample must be collected at a point downstream of all field separators, prior to the point where produced liquid is flashed to atmospheric pressure as it enters the storage tank. Sampling must be conducted under unbiased operating conditions.
2. A flash liberation test must be conducted and GOR and the mass fraction of CH_4 and CO_2 in the evolved gas determined.

The following steps outline the flash liberation test:
Step 1. The fluid sample is charged to a PVT cell.
Step 2. The cell pressure is elevated to a pressure higher than saturation pressure by injecting mercury.
Step 3. Pressure is lowered in small increments until the PVT cell is at atmospheric pressure.
Step 4. The resulting volume of solution gas and oil remaining are measured and corrected to conditions of 60°F and 14.65 psia.

3. Storage tanks equipped with a vapor recovery unit (VRU) or thermal oxidizer are exempt from reporting during periods when the destruction device is operational.

(B) The operator must determine CH_4 and CO_2 emissions using the following equation.

$$E_{CH4/CO2} = GOR * PR * MW_g / MVC * MF_{CH4/CO2} * 0.001$$

Where:

$E_{CH4/CO2}$ =	Methane or carbon dioxide emissions (metric tons/year).
GOR =	Gas-Oil Ratio (scf/bbl).
PR =	Oil production rate (bbl/measurement period).
MW_g =	Molecular weight of the gas (kg/kg-mole).
MVC =	Molar volume conversion factor.
$MF_{CH4/CO2}$ =	Mass fraction of CH_4 or CO_2 in gas (kg GHG/kg gas).
0.001=	Conversion factor.

(j) *Well Testing Venting and Flaring.* The operator must calculate well testing venting and flaring emissions as follows:

(1) The operator must collect a pressurized crude/condensate sample and determine the gas to oil ratio (GOR) of the hydrocarbon production from each well tested.

(2) The operator must estimate venting emissions using the following equation:

$$E_{a,n} = GOR * FR * D$$

Where:

$E_{a,n}$ =	Annual volumetric natural gas emissions from well testing in cubic feet under ambient conditions.
GOR =	Gas- Oil Ratio in cubic feet of gas per barrel of oil; oil here refers to hydrocarbon liquids produced of all API gravities.
FR =	Flow rate in barrels of oil per day for the well being tested.
D =	Number of days during the year the well is tested.

(3) The operator must calculate natural gas volumetric emissions at standard conditions using calculations in paragraph (r) of this section.

(4) The operator must calculate both CH_4 and CO_2 volumetric and mass emissions from volumetric natural gas emissions using calculations in paragraphs (s) and (t) of this section.

(5) The operator must calculate emissions from well testing to flares as follows:

(A) The operator must use the well testing emissions volume and gas composition as determined in paragraphs (j)(1) through (3) of this section.

(B) The operator must use the calculation methodology of flare stacks in paragraph (l) of this section to determine well testing emissions from the flare.

(k) *Associated Gas Venting and Flaring.* The operator must calculate associated gas venting and flaring emissions as follows:

(1) The operator must collect a pressurized sample of crude/condensate and determine the GOR ratio of the hydrocarbon production from each well whose associated natural gas is vented or flared.

(2) The operator must estimate venting emissions using the following equation:

$$E_{a,n} = GOR * V$$

Where:

$E_{a,n}$ = Annual volumetric natural gas emissions from associated gas venting under ambient conditions, in cubic feet.

GOR = Gas to oil ratio in cubic feet of gas per barrel of oil; oil here refers to hydrocarbon liquids produced of all API gravities.

V = Total volume of oil produced in barrels in the reporting year.

(3) The operator must calculate natural gas volumetric emissions at standard conditions using calculations in paragraph (r) of this section.

(4) The operator must calculate both CH_4 and CO_2 volumetric and mass emissions from volumetric natural gas emissions using calculations in paragraphs (s) and (t) of this section.

(5) The operator must calculate emissions from associated natural gas to flares as follows:

(A) The operator must use the associated natural gas volume and gas composition as determined in paragraph (k)(1) through (3) of this section.

(B) The operator must use the calculation methodology of flare stacks in paragraph (l) of this section to determine associated gas emissions from the flare.

(l) *Flare Stacks.* The operator must calculate emissions from each flare stack as follows:

(1) If a continuous flow measurement device is installed on the flare, the operator must use the measured flow volumes to calculate the flare gas emissions. If a continuous flow measurement device is not installed on the flare, the operator can install a flow measuring device on the flare or use engineering calculations or company records to estimate volumetric flare gas flow.

(2) If a continuous gas composition analyzer is installed on gas to the flare, the operator must use these compositions in calculating emissions. If a continuous gas composition analyzer is not installed on gas to the flare, the operator can install a continuous gas composition analyzer on the flare or use the appropriate gas compositions for each stream of hydrocarbons going to the flare as specified in subparagraphs (A)-(B) below.

(A) When the stream going to flare is natural gas, the operator must use the GHG mole percent in feed natural gas for all streams upstream of the de-methanizer and GHG mole percent in facility specific residue gas to transmission pipeline systems for all emissions sources downstream of the de-methanizer overhead for onshore natural gas processing facilities.

(B) When the stream going to the flare is a hydrocarbon product stream, such as ethane or butane, then the operator must use a representative composition from the source for the stream.

(3) The operator must determine flare combustion efficiency from manufacturer supplied flare specifications. If not available, the operator must assume a flare combustion efficiency of 98 percent.

(4) The operator must determine CO_2, CH_4, and N_2O emissions resulting from the combustion of natural gas used as pilot gas according to the requirements of section 95115 of this article.

(5) For each unique gas stream destructed in the flare, the operator must calculate annual GHG volumetric emissions at actual conditions using the applicable equations below.

(A) The operator must calculate un-combusted flare stack methane emissions using the following equation:

$$E_{a,CH4} = V_a * (1-\eta) * X_{CH4}$$

Where:

$E_{a,CH4}$ = Uncombusted methane emissions from the flare stack (scf).

V_a = Volume of gas sent to the flare (scf).

η = Flare destruction efficiency (expressed as a decimal, default = 0.98).

X_{CH4} = Concentration of methane in gas sent to the flare.

(B) The operator must calculate CO_2 combustion emissions for each unique gas stream sent flare using the following equation:

$$E_{CO2} = \eta * V * CC / MVC * 3.664 * 0.001$$

Where:

E_{CO2} = Combustion CO_2 emissions (MT of CO_2).
η = Flare destruction efficiency (expressed as a decimal, default = 0.98).
V = Volume of gas or liquid sent to the flare (scf).
CC = Carbon content of gas stream sent to the flare (kg C/kg-mole).
MVC = Molar volume conversion.
3.664 = Conversion factor (kg C to kg CO_2).
0.001 = Conversion factor (kg to metric tons).

1. The operator must calculate GHG volumetric emissions at standard conditions using calculations in paragraph (r) of this section.
2. The operator must calculate both CH_4 and CO_2 mass emissions from volumetric CH_4 and CO_2 emissions using calculation in paragraph (t) of this section.
3. The operator must calculate N_2O emissions using the emission factors for Gas Flares listed in Table 8 of section 95158.
4. This emissions source excludes any emissions calculated under other emissions sources in section 95153 of this article.

(m) *Centrifugal Compressor Wet Seal Degassing Vents.* The operator must calculate CO_2 and CH_4 emissions from centrifugal compressor wet seal degassing vents as follows:

(1) For each centrifugal compressor, the operator must determine the volume of vapors from wet seal oil degassing tanks sent to an atmospheric vent or flare using a temporary or permanent flow measurement meter such as a vane anemometer according to methods set forth in section 95154(a)(2) of this article.

(2) The operator must estimate annual emissions using meter flow measurement using the following equation:

$$E_{a,i} = MT * T * M_i * (1 - B)$$

Where:

$E_{a,i}$ = Annual GHG i (i = either CH_4 or CO_2) volumetric emissions at ambient conditions.
MT = Average meter reading of gas emissions per unit time based on semi-annual measurements.
T = Total time the compressor associated with the wet seal(s) is

operational in the reporting year.

M_i = Average mole percent of GHG i in the degassing vent gas based on semi-annual measurement; use the appropriate gas compositions in paragraph (s)(2) of this section.

B = Percentage of centrifugal compressor wet seal degassing vent gas sent to vapor recovery or fuel gas or other beneficial use as determined by keeping logs of the number of operating hours for the vapor recovery system and the amount of vent gas that is directed to the fuel gas system.

(3) The operator must calculate CH_4 and CO_2 volumetric emissions at standard conditions using paragraph (r) of this section.

(4) The operator must calculate both CH_4 and CO_2 mass emissions from volumetric emissions using calculations in paragraph (t) of this section.

(5) The operator must calculate emissions from degassing vent vapors to flares as follows:

(A) The operator must use the degassing vent vapor volume and gas composition as determined in paragraphs (m)(1) through (3) of this section.

(B) The operator must use the calculation methodology of flare stacks in paragraph (l) of this section to determine degassing vent vapor emissions from the flare.

(n) *Reciprocating Compressor Rod Packing Venting.* The operator must calculate annual CH_4 and CO_2 emissions from each reciprocating compressor rod packing venting for each applicable operational mode as follows:

(1) The operator must estimate annual emissions using a meter flow measurement using the following equation:

$$E_{a,i} = MT * T * M_i$$

Where:

$E_{a,i}$ = Annual GHG i (i = either CH_4 or CO_2) volumetric emissions at ambient conditions.

MT = Meter volumetric reading of gas emissions per unit time, under ambient conditions.

T = Total time the compressor associated with the venting is operational in the reporting year.

M_i = Mole percent of GHG i (i = either CO_2 or CH_4) in the vent gas; use the appropriate gas compositions in paragraph (s)(2) of this section.

(2) If the rod packing case is connected to an open ended vent line then the operator must use the following method to calculate emissions.

(A) The operator must measure volumetric emissions from all vents (including emissions manifolded to common vents) including rod packing, unit isolation valves, and blowdown valves using bagging according to methods set forth in section 95154(a)(3) of this article.

(B) The operator must use a temporary meter such as a vane anemometer or a permanent meter such as an orifice meter to measure emissions from all vents (including emissions manifolded to a common vent) including rod packing vents, unit isolation valves, and blowdown valves according to methods set forth in section 95154(a)(2).

(3) If the rod packing case is not equipped with a vent line, the operator must use the following method to estimate emissions:

(A) The operator must use the methods described in 95154(a) to conduct annual leak detection of fugitive emissions from the packing case into an open distance piece, or from the compressor crank case breather cap or vent with a closed distance piece.

(B) The operator must measure emissions using a high flow sampler, or calibrated bag, or appropriate meter according to methods set forth in section 95154(b) of this article.

(4) The operator must conduct one measurement for each compressor in each of the following operational modes that occurs during a reporting period:

(A) Operating.
(B) Standby, pressurized.
(C) Not operating, depressurized.

(5) The operator must calculate CH_4 and CO_2 volumetric emissions at standard conditions using calculations in paragraph (r) of this section.

(6) The operator must estimate CH_4 and CO_2 volumetric and mass emissions from volumetric natural gas emissions using the calculations in paragraphs (s) and (t) of this section.

(o) *Leak Detection and Leaker Emission Factors.* The operator must use the methods described in section 95154(a) of this article to conduct an annual leak detection of fugitive emissions from all sources listed in section 95152(d)(9), (e)(7), (f)(5), (g)(3), (h)(4), and (i)(1) of this article. This paragraph (o) applies to emissions sources in streams with gas content greater than 10 percent CH_4 plus CO_2 by weight. Emissions sources in streams with gas content less than 10 percent CH_4 plus CO_2 by weight do not need to be reported. If fugitive emissions are detected for sources listed in this paragraph, the operator must calculate emissions using the following equation for each source with fugitive emissions:

$$E_{s,i} = \text{Count} * EF * GHG_i * T$$

Where:

$E_{s,i}$ = Annual total volumetric GHG emissions at standard conditions from each component fugitive source.

Count = Total number of this type of emission source found to be leaking.

EF = Leaker emission factor for specific sources listed in Tables 2 through 7 of section 95158.

GHG_i = Concentration of GHG i, (i = either CH_4 or CO_2), in the total hydrocarbon of the feed natural gas.

T = Total time the specific source associated with the fugitive emission was operational in the reporting year, in hours.

(1) The operator must calculate GHG mass emissions at standard conditions using the calculation in paragraph (t) of this section.

(2) Operators of onshore natural gas processing facilities must use the appropriate default leaker emission factors listed in Table 2 of section 95158 for fugitive emissions detected from valves, connectors, open ended lines, pressure relief valves, meters, and centrifugal compressor dry seals.

(3) Operators of onshore natural gas transmission compression facilities must use the appropriate default leaker emission factors listed in Table 3 of section 95158 for fugitive emissions detected from connectors, block valves, control valves, compressor blowdown valves, pressure relief valves, orifice meters, other meters regulators, and open ended lines.

(4) Operators of underground natural gas storage facilities for storage stations must use the appropriate default leaker emission factors listed in Table 4 of section 95158 for fugitive emissions detected from connectors, block valves, control valves, compressor blowdown valves, pressure relief valves, orifice meters, other meters, regulators, and open ended lines.

(5) Operators of LNG storage facilities must use the appropriate default leaker emission factors listed in Table 5 of section 95158 for fugitive emissions detected from valves, pump seals, connectors, and other.

(6) Operators of LNG import and export facilities must use the appropriate default leaker emission factors listed in Table 6 of section 95158 for fugitive emissions detected from valves, pump seals, connectors, and other.

(7) Operators of natural gas distribution facilities for above ground meter regulator and gate stations must use the appropriate default leaker emission factors listed in Table 7 of section 95158 for fugitive emissions detected from connectors, block valves, control valves, pressure relief valves, orifice meters, other meters, regulators, and open ended lines.

(p) *Population Count and Emission Factors.* This paragraph applies to emissions sources listed in section 95152(c)(2), (c)(9), (c)(15), (c)(21), (d)(8), (e)(6), (f)(4), (f)(5), (g)(3), (h)(4), (i)(2), (i)(3) and (i)(4), of this article on streams with gas content greater than 10 percent CH_4 plus CO_2 by weight. Emissions sources in streams with gas content less than 10 percent CH_4 plus CO_2 by weight do not need to be reported. Operators must calculate emissions from all sources listed in this

paragraph using the following equation:

$$E_{s,i} = Count * EF * GHG_i * T$$

Where:

$E_{s,i}$ = Annual total volumetric GHG emissions at standard conditions from each fugitive source.

Count = Total number of this type of emission source at the facility.

EF = Population emission factor for specific sources listed in Tables 1 through 7 of section 95158.

GHG_i = Concentration of GHG i, (i = either CH_4 or CO_2), in produced natural gas or feed natural gas.

T = Total time the specific source associated with the fugitive emission was operational in the reporting year, in hours.

(1) Operators must calculate both CH_4 and CO_2 mass emissions from volumetric emissions using the calculation in paragraph (t) of this section.

(2) Operators of onshore petroleum and natural gas production facilities must use the appropriate default population emission factors listed in Table 1 of section 95158 for fugitive emissions from valves, connectors, open ended lines, pressure relief valves, compressor starter gas vent, pump, flanges, other, and CBM well water production. Where facilities conduct EOR operations, the emissions factor listed in Table 1 of section 95158 must be used to estimate all stream of gases, including recycle CO_2 stream. In cases where the stream is almost all CO_2, the emissions factors in Table 1 of section 95158 must be assumed to be for CO_2 instead of natural gas.

(3) Operators of onshore natural gas processing facilities must use the appropriate default population emission factor listed in Table 2 of section 95158 for fugitive emission from gathering pipelines.

(4) Operators of underground natural gas storage facilities for storage wellheads must use the appropriate default population emission factors listed in Table 4 of section 95158 for fugitive emissions from connectors, valves, pressure relief valves, and open ended lines.

(5) Operators of LNG storage facilities must use the appropriate default population emission factors listed in Table 5 of section 95158 for fugitive emissions from vapor recovery compressors.

(6) Operators of LNG import and export facilities must use the appropriate default population emission factor listed in Table 6 of section 95158 for fugitive emissions from vapor recovery compressors.

(7) Operators of natural gas distribution facilities must use the appropriate default population emission factors listed in Table 7 of section 95158 for fugitive emissions from below grade metering & regulating (M&R) stations, gathering pipelines, mains, and services.

(q) *Offshore Petroleum and Natural Gas Production Facilities.* Operators must report GHG emissions from all "stationary fugitive" and "stationary vented" sources as identified in the Minerals Management Service (MMS) Gulfwide Offshore Activity Data System (GOADS) study (2005 Gulfwide Emission Inventory Study MMS 2007-

067) for each platform. Operators of offshore production facilities who had not previously reported under the MMS GOADS program must collect monthly activity data from platform sources for the first reporting year in accordance with the MMS GOADS program instructions. Annual emissions must be calculated using the MMS GOADS emission factors and methods.

(1) In subsequent reporting years, facilities not reporting under GOADS must follow the same data collection cycle as GOADS in collecting new activity data monthly to estimate emissions and report emissions.
(2) For each reporting year that does not overlap with the GOADS reporting year, operators must report the last reported emissions data with emissions adjusted based on the operating time for each platform.
(3) If MMS discontinues or delays their GOADS survey by more than 4 years, then platform operators must collect monthly activity data every 4 years from platform sources in accordance with the MMS GOADS program instructions, and annual emissions must be calculated using the MMS GOADS emission factors and methods.

(r) *Volumetric Emissions.* Operators must calculate volumetric emissions at standard conditions as specified in paragraphs (r)(1) or (2) of this section.

(1) Operators must calculate natural gas volumetric emissions at standard conditions by converting ambient temperature and pressure of natural gas emissions to standard temperature and pressure natural gas using the following equation:

$$E_{s,n} = E_{a,n} * (460 + T_s) * P_a / (460 + T_a) * P_s$$

Where:
$E_{s,n}$ = Natural gas volumetric emissions at standard temperature and pressure (STP) conditions.
$E_{a,n}$ = Natural gas volumetric emissions at ambient conditions.
T_s = Temperature at standard conditions (°F).
T_a = Temperature at actual emission conditions (°F).
P_s = Absolute pressure at standard conditions (inches of Hg).
P_a = Absolute pressure at ambient conditions (inches of Hg).

(2) Calculate GHG volumetric emissions at standard conditions by converting ambient temperature and pressure of GHG emissions to standard temperature and pressure using the following equation:

$$E_{s,i} = E_{a,i} * (460 + T_s) * P_a / (460 + T_a) * P_s$$

Where:
$E_{s,i}$ = GHG i volumetric emissions at standard temperature and pressure

(STP) conditions.
$E_{a,i}$ = GHG i volumetric emissions at actual conditions.
T_s = Temperature at standard conditions (°F).
T_a = Temperature at actual emission conditions (°F).
P_s = Absolute pressure at standard conditions (inches of Hg).
P_a = Absolute pressure at ambient conditions (inches of Hg).

(s) *GHG Volumetric Emissions.*

(1) Operators must estimate CH_4 and CO_2 emissions from natural gas emissions using the following equation:

$$E_{s,i} = E_{s,n} * M_i$$

Where:
$E_{s,i}$ = GHG i (i = either CH_4 or CO_2) volumetric emissions at standard conditions.
$E_{s,n}$ = Natural gas volumetric emissions at standard conditions.
M_i = Mole percent of GHG i (i = CH_4 or CO_2) in the natural gas.

(2) For the equation in paragraph (s)(1), the mole percent, M_i, must be the annual average mole percent for each facility, as specified in paragraphs (s)(2)(A) through (G) of this section.

(A) GHG mole percent in produced natural gas for onshore petroleum and natural gas production facilities. If operators have a continuous gas composition analyzer installed for produced natural gas, the operator must use these values in calculating emissions. If the operator does not have a continuous gas composition analyzer installed, then quarterly samples must be taken according to methods set forth in section 95154(a)(2) of this article.

(B) GHG mole percent in feed natural gas for all emissions sources upstream of the de-methanizer and GHG mole percent in facility specific residue gas to transmission pipeline systems for all emissions sources downstream of the de-methanizer overhead for onshore natural gas processing facilities. If the operator has a continuous gas composition analyzer on feed natural gas, the operator must use these values in calculating emissions. If the operator does not have a continuous gas composition analyzer, then quarterly samples must be taken according to methods set forth in section 95154(a)(2) of this article.

(C) GHG mole percent in transmission pipeline natural gas that passes through the facility for onshore natural gas transmission compression facilities.

(D) GHG mole percent in natural gas stored in underground natural gas storage facilities.

(E) GHG mole percent in natural gas stored in LNG storage facilities.

(F) GHG mole percent in natural gas stored in LNG import and export facilities.

(G) GHG mole percent in local distribution pipeline natural gas that passes through the facility for natural gas distribution facilities.

(t) *GHG Mass Emissions.* The operator must calculate GHG mass emissions at standard conditions by converting the GHG volumetric emissions into mass emissions using the following equation:

$$Mass_{s,i} = E_{s,i} * \rho_i * 10^{-3}$$

Where:

$Mass_{s,i}$ = GHG i (either CH_4 or CO_2) mass emissions at standard conditions in metric tons.

$E_{s,i}$ = GHG i (either CH_4 or CO_2) volumetric emissions at standard conditions, in cubic feet.

ρ_i = Density of GHG i, 0.053 kg/ft^3 for CO_2 and 0.0193 kg/ft^3 for CH_4.

(u) *EOR Injection Pump Blowdown.* The operator must calculate pump blowdown emissions as follows:

(1) The operator must calculate the total volume in cubic feet (including from pipelines, compressors and vessels) between isolation valves.

(2) The operator must retain logs of the number of blowdowns per reporting period according to the recordkeeping requirements of section 95105 of this article.

(3) The operator must calculate the total annual venting emissions using the following equation:

$$Mass_{c,i} = N * V_v * R_c * GHG_i * 10^{-3}$$

Where:

$Mass_{c,i}$ = Annual EOR injection gas venting emissions in metric tons at critical conditions "c" from blowdowns.

N = Number of blowdowns for the equipment in reporting year.

V_v = Total volume in cubic feet of blowdown equipment chambers (including pipelines, compressors, manifolds and vessels) between isolation valves.

R_c = Density of critical phase EOR injection gas in kg/ft^3.

GHG_i = Mass fraction of GHG_i in critical phase injection gas.

(v) Produced Water Dissolved CO_2. The operator must calculate dissolved CO_2 in produced water as follows:

(1) The operator must determine the amount of CO_2 retained in produced water at

STP conditions. Quarterly samples must be taken according to methods set forth in section 95154(a)(2) of this article to determine retention of CO_2 in produced water immediately downstream of the separator where hydrocarbon liquids and produced water are separated. The operator must use the average of the quarterly analysis for the reporting period.

(2) The operator must estimate emissions using the following equation:

$$\frac{Mass_{s,CO2} * S_{pw} * V_{pw}}{\quad}$$

Where:

$Mass_{s,CO2}$ = Annual CO_2 emissions from CO_2 retained in produced water beyond tankage, in metric tons.

S_{pw} = Amount of CO_2 retained in produced water in metric tons per barrel, under standard conditions.

V_{pw} = Total volume of produced water produced in barrels in the reporting year.

(3) EOR operations that route produced water from separation directly to re-injection into the hydrocarbon reservoir in a closed loop system without any leakage to the atmosphere are exempt from paragraph (v) of this section.

(w) *Portable Equipment Combustion Emissions.* The operator must calculate emissions from portable equipment pursuant to section 95115 of this article.

NOTE: Authority cited: Sections 39600, 39601, 39607, 39607.4, 41511, 38510, and 38530, Health and Safety Code. Reference: Sections 39600, 41511, and 38530, Health and Safety Code.

§ 95154. Monitoring and QA/QC Requirements.

(a) The operator must use the method described as follows to conduct annual leak detection of fugitive emissions from all source types listed in section 95153(n)(3)(A) and 95153(o) of this article in operation or on standby mode that occur during a reporting period.

(1) Optical gas imaging instrument. The operator must use an optical gas imaging instrument for fugitive emissions detection in accordance with 40 CFR part 60, subpart A, §60.18(i)(1) and (2), Alternative Work Practice for Monitoring Equipment Leaks (revised as of July 1, 2009). In addition, the operator must operate the optical gas imaging instrument to image the source types required by this article in accordance with the instrument manufacturer's operating parameters.

(2) All flow meters, composition analyzers and pressure gauges that are used to provide data for the GHG emissions calculations must use measurement

methods, maintenance practices, and calibration methods that are consistent with the requirements of section 95103(k).

(3) The operator must use calibrated bags (also known as vent bags) only where the emissions are at near-atmospheric pressures such that it is safe to handle and capture all the emissions, below the maximum temperature specified by the vent bag manufacturer, and the entire emissions volume can be encompassed for measurement.

(A) The operator must hold the bag in place enclosing the emissions source to capture the entire emissions and record the time required for completely filling the bag. If the bag inflates in less than one second, assume one second inflation time.

(B) The operator must perform three measurements of the time required to fill the bag and report the emissions as the average of the three readings.

(C) The operator must estimate natural gas volumetric emissions at standard conditions using the calculations in section 95153(r) of this article.

(D) The operator must estimate CH_4 and CO_2 volumetric and mass emissions from volumetric natural gas emissions using the calculations in section 95153(s) and (t) of this article.

(b) The operator must use a high volume sampler to measure emissions within the capacity of the instrument.

(1) A technician following manufacturer instructions must conduct measurements, including equipment manufacturer operating procedures and measurement methodologies relevant to using a high volume sampler, including positioning the instrument for complete capture of the fugitive emissions without creating backpressure on the source.

(2) If the high volume sampler, along with all attachments available from the manufacturer, is not able to capture all the emissions from the source then the operator must use anti-static wraps or other aids to capture all emissions without violating operating requirements as provided in the instrument manufacturer's manual.

(3) The operator must estimate CH_4 and CO_2 volumetric and mass emissions from volumetric natural gas emissions using the calculations in section 95153(s) and (t) of this article.

(4) The operator must calibrate the instrument at 2.5 percent CH_4 with 97.5 percent air and 100 percent CH_4 by using calibrated gas samples and by following the manufacturer's instructions for calibration.

NOTE: Authority cited: Sections 39600, 39601, 39607, 39607.4, 41511, 38510, and 38530, Health and Safety Code. Reference: Sections 39600, 41511, and 38530, Health and Safety Code.

§ 95155. Procedures for Estimating Missing Data.

(a) A complete record of all estimated and/or measured parameters used in the GHG emissions calculations is required. If data are lost or an error occurs during annual emissions estimation or measurements, the operator must repeat the estimation or measurement activity for those sources within the measurement period. In cases where repeat sampling and/or analysis cannot be completed, the operator must follow the missing data substitution procedures below.

(1) To substitute for missing data for emissions reported under section 95115 of this article (stationary combustion units and units using continuous emissions monitoring systems), the operator must follow the requirements of section 95129 of this article.

(2) If data required by this subarticle are missing and additional sampling and/or analysis is not possible, the operator must generate a substitute value as follows:

(A) If the analytical data capture rate is at least 90 percent for the data year, the operator must substitute each missing value using available process data.

(B) If the analytical data capture rate is at least 80 percent but not at least 90 percent for the data year, the operator must substitute each missing value with the highest quality assured value recorded for the parameter during the given data year, as well as the two previous data years.

(C) If the analytical data capture rate is less than 80 percent for the data year, the operator must substitute each missing value with the highest quality assured value recorded for the parameter in all records kept according to section 95105(a).

NOTE: Authority cited: Sections 39600, 39601, 39607, 39607.4, 41511, 38510, and 38530, Health and Safety Code. Reference: Sections 39600, 41511, and 38530, Health and Safety Code.

§ 95156. Data Reporting Requirements.

In addition to the information required by 40 CFR §98.3(c), each annual report must contain reported emissions as specified in this section.

(a) The operator must report annual emissions separately for each of the industry segments listed in paragraphs (a)(1) through (a)(8) of this section. For each segment, the operator must report emissions from each source type in the aggregate, unless specified otherwise. For example, the operator of an underground natural gas storage operation with multiple reciprocating compressors must report emissions from all reciprocating compressors as an aggregate number.

(1) Onshore petroleum and natural gas production.

(A) Petroleum and natural gas produced using thermal EOR.
(B) Petroleum and natural gas produced using production methods other than thermal EOR.

(2) Offshore petroleum and natural gas production.
(3) Onshore natural gas processing.
(4) Onshore natural gas transmission compression.
(5) Underground natural gas storage.
(6) LNG storage.
(7) LNG import and export.
(8) Natural gas distribution. The operator must report each source in the aggregate for pipelines and for Metering and Regulating (M&R) stations.

(b) The operator must report emissions separately for standby equipment.

(c) The operator must report activity data for each aggregated source type as follows:

(1) Count of natural gas pneumatic high bleed devices.
(2) Count of natural gas pneumatic low bleed devices.
(3) Count of natural gas driven pneumatic pumps.
(4) For each acid gas removal unit the operator must report the following:

(A) Total volume of natural gas flow into the acid gas removal unit.
(B) Total volume of natural gas flow out of the acid gas removal unit.
(C) Volume weighted CO_2 content of natural gas into the acid gas removal unit.

(5) For each dehydrator unit the operator must report the following:

(A) Glycol dehydrators:

1. Glycol dehydrator feed natural gas flow rate.
2. Glycol dehydrator absorbent circulation pump type.
3. Glycol dehydrator absorbent circulation rate.
4. Whether stripper gas is used in glycol dehydrator.
5. Whether a flash tank separator is used in glycol dehydrator.

(B) Desiccant dehydrators:

1. The number of desiccant dehydrators operated.

(6) Count of wells vented to the atmosphere for liquids unloading for each field in the basin.
(7) Count of wells venting during well completions for each field in the basin.

(A) Number of conventional completions.
(B) Number of completions involving hydraulic fracturing.

(8) Count of wells venting during well workovers for each field in the basin.

(A) Number of conventional well workovers involving well venting to the atmosphere.
(B) Number of unconventional well workovers involving well venting to the atmosphere.

(9) For each compressor blowdown vent stack the operator must report the following for each compressor:

(A) Type of compressor whether reciprocating or centrifugal.
(B) Compressor capacity in horse powers.
(C) Volume of gas between isolation valves.
(D) Number of blowdowns per year.

(10) For each estimate of gas emitted from liquids sent to atmospheric tank using E&P Tank, the operator must report the following:

(A) Immediate upstream separator temperature and pressure.
(B) Sales oil API gravity.
(C) Estimate of individual tank or tank battery capacity in barrels.
(D) Oil, hydrocarbon condensate and water sent to tank(s) in barrels.
(E) Control measure: either vapor recovery system or flaring of tank vapors.

(11) For tank emissions identified using optical gas imaging instrument per section 95154(a) of this article, the operator must report the following for each tank:

(A) Immediate upstream separator temperature and pressure.
(B) Sales oil API gravity.
(C) Tank capacity in barrels.
(D) Tank throughput in barrels.
(E) Control measure: either vapor recovery system or flaring of tank vapors.
(F) Optical gas imagining instrument used.
(G) Meter used for measuring emissions.
(H) List of emissions sources routed to the tank.

(12) For well testing, the operator must report the following for each field in the basin:

(A) Number of wells tested in reporting period.
(B) Average gas to oil ratio for each field.
(C) Average flow rate during testing for each field.
(D) Average number of days the well is tested.

(E) Whether the hydrocarbons produced during testing are vented or flared.

(13) For associated natural gas venting, the operator must report the following for each field in the basin:

(A) Number of wells venting or flaring associated natural gas in reporting period.
(B) Average gas to oil ratio for each field.
(C) Average volume of oil produced per well per field.
(D) Whether the associated natural gas is vented or flared.

(14) For flare stacks, the operator must report the following for each flare:

(A) Whether the flare has a continuous flow monitor.
(B) If using engineering estimation methods, identify sources of emissions going to the flare.
(C) Whether the flare has a continuous gas analyzer.
(D) Identify the proportion of total natural gas to pure hydrocarbon stream being sent to the flare annually for the reporting period.
(E) Flare combustion efficiency.

(15) For well venting for liquids unloading, the operator must report the following by field, basin, and well tubing size:

(A) Number of wells being unloaded for liquids in reporting year.
(B) Average number of unloading(s) per well per reporting year.
(C) Average volume of natural gas produced per well per reporting year during liquids unloading.

(16) For well completions and workovers, the operator must report the following for each field in the basin:

(A) Number of wells completed (worked over) in reporting year.
(B) Average number of days required for completion (workover).
(C) Average volume of natural gas produced per well per reporting year during well completion (workover).

(17) For compressor wet seal degassing vents, the operator must report the following for each degassing vent:

(A) Number of wet seals connected to the degassing vent.
(B) Number of compressors whose wet seals are connected to the degassing vent.
(C) Total throughput of compressors whose wet seals are connected to the degassing vent.
(D) Type of meter used for making measurements.

(E) Whether emissions estimate is based on a continuous or one time measurement.
(F) Total time the compressor(s) associated with the degassing vent stack is operating. Sum the hours of operation if multiple compressors are connected to the vent stack.
(G) Proportion of vent gas recovered for fuel gas or sent to a flare.

(18) For reciprocating compressor rod packing, the operator must report the following per rod packing:

(A) Total throughput of the reciprocating compressor whose rod packing emissions is being reported.
(B) Total time in hours the reciprocating compressor is in operating mode.
(C) Whether or not the rod packing case is connected to an open ended line.
(D) If rod packing is connected to an open ended line, report type of device used for measurement of emissions.
(E) If rod packing is not connected to an open ended vent line, report the locations from where the emissions from the rod packing are detected.

(19) For fugitive emissions sources using emission factors for estimating emissions, the operator must report the following:

(A) Component count for each fugitive emissions source.
(B) CH_4 and CO_2 in produced natural gas for onshore petroleum and natural gas production.

(20) For EOR injection pump blowdown, the operator must report the following per pump:

(A) Pump capacity.
(B) Volume of gas between isolation valves.
(C) Number of blowdowns per year.
(D) Supercritical phase EOR injection gas density.

(21) For hydrocarbon liquids dissolved CO_2, the operator must report the following for each field in the basin:

(A) Volume of crude oil produced.

(22) For produced water dissolved CO_2 the operator must report the following for each field in the basin:

(A) Volume of produced water produced.

(d) Minimum, maximum and average throughput for each operation listed in paragraphs (a)(1) through (a)(8) of this section.

(e) For offshore petroleum and natural gas production facilities, the number of connected wells, and whether the wells are producing oil, gas, or both.

(f) The operator must report emissions separately for portable equipment for the following source types: drilling rigs, dehydrators, compressors, electrical generators, steam boilers, and heaters.

(1) Aggregate emissions by source type.
(2) Report count of each source type.

NOTE: Authority cited: Sections 39600, 39601, 39607, 39607.4, 41511, 38510, and 38530, Health and Safety Code. Reference: Sections 39600, 41511, and 38530, Health and Safety Code.

§ 95157. Records That Must be Retained.

In addition to the information required by 40 CFR §98.3(g), the operator must retain the following records according to the recordkeeping requirements of section 95105 of this article:

(a) Dates on which measurements were conducted.

(b) Results of all emissions detected and measurements.

(c) Calibration reports for detection and measurement instruments used.

(d) Inputs and outputs of calculations or emissions computer model runs used for engineering estimation of emissions.

NOTE: Authority cited: Sections 39600, 39601, 39607, 39607.4, 41511, 38510, and 38530, Health and Safety Code. Reference: Sections 39600, 41511, and 38530, Health and Safety Code.

§ 95158. Default Emission Factor Tables.

Table 1. Default Whole Gas Emission Factors for Onshore Production

Onshore production	*Emission Factor (scf/hour/ component)*
Population Emission Factors--All Components, Gas Service	
Valve	0.08
Connector.	0.01
Open-ended Line	0.04
Pressure Relief Valve	0.17
Low-Bleed Pneumatic Device Vents	2.75
Gathering Pipelines[1]	2.81
CBM Well Water Production[2]	0.11
Population Emission Factors--All Components, Light Crude Service[3]	
Valve	0.04
Connector.	0.01
Open-ended Line	0.04
Pump	0.01
Other[5]	0.24
Population Emission Factors--All Components, Heavy Crude Service[4]	
Valve	0.04
Connector	0.01
Open-ended Line	0.04
Pump	0.01
Other[5]	0.24
Valve	0.001
Flange	0.001
Connector (other)	0.0004
Open-ended Line	0.01
Other[5]	0.003

[1] Emission Factor is in units of "scf/hour/mile."
[2] Emission Factor is in units of "scf methane/gallon," in this case the operating factor is "gallons/year" and do not multiply by methane content.
[3] Hydrocarbon liquids greater than or equal to 20*API are considered "light crude."
[4] Hydrocarbon liquids less than 20*API are considered "heavy crude."
[5] "Others" category includes instruments, loading arms, pressure relief valves, stuffing boxes, compressor seals, dump lever arms, and vents.

Table 2. Default Total Hydrocarbon Emission Factors for Processing

Processing	*Before de-methanizer emission factor (scf/hour/ component)*	*After de-methanizer Emission factor (scf/hour/ component)*
Leaker Emission Factors--Reciprocating Compressor Components, Gas Service		
Valve	15.88	18.09
Connector.	4.31	9.10
Open-ended Line	17.90	10.29
Pressure Relief Valve	2.01	30.46
Meter	0.02	48.29
Leaker Emission Factors--Centrifugal Compressor Components, Gas Service		
Valve	0.67	2.51
Connector.	2.33	3.14
Open-ended Line	17.90	16.17
Dry Seal	105	105
Leaker Emission Factors--Other Components, Gas Service		
Valve		6.42
Connector		5.71
Open-ended Line		11.27
Pressure Relief Valve		2.01
Meter		2.93
Population Emission Factors--Other Components, Gas Service		
Gathering Pipelines[1]		2.81

[1] Emission Factor is in units of "scf/hour/mile."

Table 3. Default Methane Emission Factors for Transmission

Transmission	*Emission Factor (scf/hour/ component)*
Leaker Emission Factors--All Components, Gas Service	
Connector	2.7
Block Valve	10.4
Control Valve	3.4
Compressor Blowdown Valve	543.5
Pressure Relief Valve	37.2
Orifice Meter	14.3
Other Meter	0.1
Regulator	9.8
Open-ended Line	21.5
Population Emission Factors--Other Components, Gas Service	
Low-Bleed Pneumatic Device Vents	2.57

Table 4. Default Methane Emission Factors for Underground Storage

Underground Storage	*Emission Factor (scf/hour/ component)*
Leaker Emission Factors--Storage Station, Gas Service	
Connector	0.96
Block Valve	2.02
Control Valve	3.94
Compressor Blowdown Valve	66.15
Pressure Relief Valve	19.80
Orifice Meter	0.46
Other Meter	0.01
Regulator	1.03
Open-ended Line	6.01
Population Emission Factors--Storage Wellheads, Gas Service	
Connector	0.01
Valve	0.10
Pressure Relief Valve	0.17
Open-ended Line	0.03
Population Emission Factors--Other Components, Gas Service	
Low-Bleed Pneumatic Device Vents	2.57

Table 5. Default Methane Emission Factors for Liquefied Natural Gas (LNG) Storage

LNG Storage	*Emission Factor (scf/hour/ component)*
Leaker Emission Factors--LNG Storage Components, LNG Service	
Valve	1.19
Pump Seal	4.00
Connector	0.34
Other[1]	1.77
Population Emission Factors--LNG Storage Compressor, Gas Service	
Vapor Recovery Compressor	6.81

[1] "Other" equipment type should be applied for any equipment type other than connectors, pumps, or valves.

Table 6. Default Methane Emission Factors for LNG Terminals

LNG Terminals	*Emission Factor (scf/hour/ component)*
Leaker Emission Factors--LNG Storage Components, LNG Service	
Valve	1.19
Pump Seal	4.00
Connector	0.34
Other	1.77
Population Emission Factors-- LNG Terminals Compressor, Gas Service	
Vapor Recovery Compressor	6.81

Table 7. Default Methane Emission Factors for Distribution

Distribution	*Emission Factor (scf/hour/ component)*
Leaker Emission Factors--Above Grade M&R Stations Components, Gas Service	
Connector	1.69
Block Valve	0.557
Control Valve	9.34
Pressure Relief Valve	0.270
Orifice Meter	0.212
Regulator	0.772
Open-ended Line	26.131
Population Emission Factors--Below Grade M&R Stations Components, Gas Service[1]	
Below Grade M&R Station, Inlet Pressure >300 psig	1.30
Below Grade M&R Station, Inlet Pressure 100 to 300 psig	0.20
Below Grade M&R Station, Inlet Pressure <100 psig	0.10
Population Emission Factors--Distribution Mains, Gas Service[2]	
Unprotected Steel	12.58
Protected Steel	0.35
Plastic	1.13
Copper	27.25
Population Emission Factors--Distribution Services, Gas Service[2]	
Unprotected Steel	0.19
Protected Steel	0.02
Plastic	0.001
Copper	0.03

[1] Emission Factor is in units of "scf/hour/station."
[2] Emission Factor is in units of "scf/hour/service."

Table 8. Default Nitrous Oxide Emission Factors for Gas Flaring

		Emission Factor (metric tons/MMscfgas production or receipts)
Population Emission Factors--Gas Flaring		
	Gas Production	5.90E-07
	Sweet Gas Processing	7.10E-07
	Sour Gas Processing	1.50E-06
	Conventional Oil Production[1]	1.00E-04
	Heavy Oil Production[2]	7.30E-05

[1] Emission Factor is in units of "metric tons/barrel conventional oil production."
[2] Emission Factor is in units of "metric tons/barrel heavy oil production."

NOTE: Authority cited: Sections 39600, 39601, 39607, 39607.4, 41511, 38510, and 38530, Health and Safety Code. Reference: Sections 39600, 41511, and 38530, Health and Safety Code.

APPENDIX A

to the Regulation for the Mandatory Reporting
of Greenhouse Gas Emissions

ARB COMPENDIUM OF EMISSION FACTORS AND METHODS TO SUPPORT MANDATORY REPORTING OF GREENHOUSE GAS EMISSIONS

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ARB COMPENDIUM OF EMISSION FACTORS AND METHODS TO SUPPORT MANDATORY REPORTING OF GREENHOUSE GAS EMISSIONS

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~~1. Introduction~~

~~The contents of this compendium specify acceptable methods and emission factors that operators must use when preparing greenhouse gas emissions data reports for submission to the California Air Resources Board (ARB), as specified in the ARB Regulation for the Mandatory Reporting of Greenhouse Gas Emissions.~~

2. Unit Conversions

Table 1. Conversion Table		
To Convert From	To	Multiply By
Grams (g)	Tonnes (metric)	1×10^{-6}
Kilograms (kg)	Tonnes (metric)	1×10^{-3}
Megagrams	Tonnes (metric)	1
Gigagrams	Tonnes (metric)	1×10^{-3}
Pounds (lbs)	Tonnes (metric)	4.5359×10^{-4}
Tons (long)	Tonnes (metric)	1.016
Tons (short)	Tonnes (metric)	0.9072
Barrels	Cubic metres (m^3)	0.15898
Cubic feet (ft^3)	Cubic metres (m^3)	0.028317
Liters	Cubic meters (m^3)	1×10^{-3}
Cubic yards	Cubic meters (m^3)	0.76455
Gallons (liquid, US)	Cubic meters (m^3)	3.7854×10^{-3}
Imperial gallon	Cubic meters (m^3)	4.54626×10^{-3}
Joule	Gigajoules (GJ)	1×10^{-9}
Kilojoule	Gigajoules (GJ)	1×10^{-6}
Megajoule	Gigajoules (GJ)	1×10^{-3}
Terajoule (TJ)	Gigajoules (GJ)	1×10^{3}
Btu	Gigajoules (GJ)	1.05506×10^{-6}
Kilocalorie	Gigajoules (GJ)	4.187×10^{-6}
Tonne oil eq. (toe)	Gigajoules (GJ)	41.86
kWh	Gigajoules (GJ)	3.6×10^{-3}
Btu / ft^3	GJ / m^3	3.72589×10^{-5}
Btu / lb	GJ / Tonnes (metric)	2.326×10^{-3}
Lb / ft^3	Tonnes (metric) / m^3	1.60185×10^{-2}
Psi	Bar	0.0689476
Kgf / cm^3 (tech atm)	Bar	0.980665
Atm	Bar	1.01325
Mile	Kilometer	1.6093
Hectares	Acres	2.471
Barrels	Gallons (liquid, US)	42

3. Global Warming Potentials

According to the Intergovernmental Panel on Climate Change (IPCC), the global warming potential (GWP) of a greenhouse gas is defined as the ratio of the time-integrated radiative forcing from the instantaneous release of 1 kilogram (kg) of a trace substance relative to that of 1 kg of a reference gas. The reference gas used is CO_2. The values given below are those reported in the IPCC Second Assessment Report (IPCC 1996). These values are used to be consistent with other statewide and national Greenhouse Gas (GHG) inventories. Operators must use these values when converting emissions of greenhouse gases to carbon dioxide equivalent values (CO_2e) for purposes of estimating *de minimis* or other emissions as specified in this article.

Table 2. Global Warming Potentials (100-Year Time Horizon)

Gas	GWP
CO_2	1
CH_4*	21
N_2O	310
HFC-23	11,700
HFC-32	650
HFC-125	2,800
HFC-134a	1,300
HFC-143a	3,800
HFC-152a	140
HFC-227ea	2,900
HFC-236fa	6,300
HFC-4310mee	1,300
CF_4	6,500
C_2F_6	9,200
C_4F_{10}	7,000
C_6F_{14}	7,400
SF_6	23,900

* The CH_4 GWP includes the direct effects and those indirect effects due to the production of tropospheric ozone and stratospheric water vapor. The indirect effect due to the production of CO_2 is not included.

Source: IPCC Climate Change 1995: The Science of Climate Change. (1996) Intergovernmental Panel on Climate Change, J.T. Houghton, L.G. Meira Filho, B.A. Callander, N. Harris, A. Kattenberg, and K. Maskell, eds. Cambridge University Press. Cambridge, U.K.

4. Method for Fuel Use to Carbon Dioxide Emissions Estimations

The following table shows the approximate amount of fuel that, when fully combusted, would result in 25,000 and 2,500 metric tonnes of CO_2 for selected common fuel types.

The 25,000 metric tonne threshold is the level at or above which general stationary sources of combustion are required to report under the regulation. Similarly, the 2,500 metric tonne threshold is the level at or above which electricity generating facilities ≥1MW are required to report. This information is provided to give operators a rough estimate of whether or not a given facility falls within the scope of ARB's mandatory reporting program. However, this table alone may not be used to demonstrate that a facility has no reporting obligation.

These tables are based on the ARB accepted emission factors which are set forth in this document. If an operator is combusting multiple fuels types, or is using a fuel type not listed in this table, then the operator must multiply the amount of fuel consumed annually for each fuel type by the ARB provided emission factor and sum the emissions to determine annual CO_2 emissions from stationary combustion.

Table 3. Fuel Amounts Resulting in 25,000 or 2,500 MT of CO_2 by Fuel Type

Fuel Type	Fuel Units	Kg CO_2/Unit	Amount of fuel to produce 25,000 MT CO_2	Amount of fuel to produce 2,500 MT CO_2
Natural Gas (unspecified)	scf	0.05	459,140,464	45,914,046
	MMBtu	53.02	471,520	47,152
LPG (energy use)	Gal	5.79	4,317,757	431,776
Distillate Fuel (#1,2 &4)	Gal	10.14	2,466,011	246,601
Motor Gasoline	Gal	8.80	2,841,174	284,117
Landfill Gas	MMBtu	52.03	480,503	48,050
	scf	0.025*	916,301,950	91,630,195
Coal (Unspecified Other Industrial)	Short Ton	2,082.89	12,003	1,200
Jet Fuel	Gal	9.56	2,614,682	261,468
Kerosene	Gal	9.75	2,562,972	256,297
Petroleum Coke	MMBtu	102.04	244,996	24,500
	Short Ton	2530.70	9,879	988
Crude Oil	Gal	10.29	2,430,348	243,035

*Note: The emission factor shown includes only the CO_2 emissions from the combustion of landfill gas. It does not include the CO_2 pass-through emissions.

5. Emission Factors

When working with the following emission factor tables the molar mass ratio of carbon dioxide to carbon (CO_2/C) is assumed to be 3.664. Complete oxidation is assumed for all fuels (oxidation factor = 1).

(a) Default Carbon Content, Heat Content, and Carbon Dioxide Emission Factors for Stationary Combustion

The default heat contents specified in Table 4 are provided for use with sections 95125(a) and (b) of the regulation.

The default carbon dioxide emission factors from stationary combustion on a heat content basis (kg CO_2 / MMBtu) specified in Table 4 and Table 5 are provided for use with sections 95125(a), (c) and (h) of the regulation.

Table 4. Default Carbon Content, Heat Content, and Carbon Dioxide Emission Factors from Stationary Combustion by Fuel Type

Fuel Type	Default Carbon Content	Default Heat Content	Default CO_2 Emission Factor	Default CO_2 Emission Factor
Coal and Coke	kg C / MMBtu	MMBtu / Short Ton	kg CO_2 / Short Ton	kg CO_2 / MMBtu
Anthracite	28.26	25.09	2,597.94	103.54
Bituminous	25.49	24.93	2,328.35	93.40
Sub-bituminous	26.48	17.25	1,673.64	97.02
Lignite	26.30	14.21	1,369.32	96.36
Unspecified (Residential/Commercial)	26.00	22.24	2,118.67	95.26
Unspecified (Industrial Coking)	25.56	26.28	2,461.17	93.65
Unspecified (Other Industrial)	25.63	22.18	2,082.89	93.91
Unspecified (Electric Power)	25.76	19.97	1,884.86	94.38
Coke	27.85	24.80	2,530.65	102.04
Natural Gas (By Heat Content)	kg C / MMBtu	Btu / Standard cubic foot	kg CO_2 / Standard cubic ft.	kg CO_2 / MMBtu
975 to 1,000 Btu / Standard cubic foot	14.73	n/a	n/a	53.97
1000 to 1,025 Btu / Std cubic foot	14.43	n/a	n/a	52.87
1025 to 1,050 Btu / Std cubic foot	14.47	n/a	n/a	53.02
1050 to 1,075 Btu / Std cubic foot	14.58	n/a	n/a	53.42
1075 to 1,100 Btu / Std cubic foot	14.65	n/a	n/a	53.68
Greater than 1,100 Btu / Std cubic foot	14.92	n/a	n/a	54.67
Unspecified (Weighted U.S. Average)	14.47	1,027	0.0544	53.02

Table 4. Default Carbon Content, Heat Content, and Carbon Dioxide Emission Factors from Stationary Combustion by Fuel Type (continued)

Petroleum Products	kg C / MMBtu	MMBtu / Barrel	kg CO_2 / gallon	kg CO_2 / MMBtu
Asphalt & Road Oil	20.62	6.636	11.94	75.55
Aviation Gasoline	18.87	5.048	8.31	69.14
Distillate Fuel Oil (#1, 2 & 4)	19.95	5.825	10.14	73.10
Jet Fuel	19.33	5.670	9.56	70.83
Kerosene	19.72	5.670	9.75	72.25
LPG (energy use)	17.19	3.861	5.79	62.98
- Propane	17.20	3.824	5.74	63.02
- Ethane	16.25	2.916	4.13	59.54
- Isobutane	17.75	4.162	6.44	65.04
- n-Butane	17.72	4.328	6.69	64.93
Lubricants	20.24	6.065	10.71	74.16
Motor Gasoline	19.33	5.218	8.80	70.83
Residual Fuel Oil (#5 & 6)	21.49	6.287	11.79	78.74
Crude Oil	20.33	5.800	10.29	74.49
Naphtha (<401 deg. F)	18.14	5.248	8.30	66.46
Natural Gasoline	18.24	4.620	7.35	66.83
Other Oil (>401 deg. F)	19.95	5.825	10.14	73.10
Pentanes Plus	18.24	4.620	7.35	66.83
Petrochemical Feedstocks	19.37	5.428	9.17	70.97
Petroleum Coke	27.85	6.024	14.64	102.04
Still Gas	17.51	6.000	9.17	64.16
Special Naphtha	19.86	5.248	9.09	72.77
Unfinished Oils	20.33	5.825	10.33	74.49
Waxes	19.81	5.537	9.57	72.58
Other Solid Fuels	**kg C / MMBtu**	**MMBtu / Short Ton**	**kg CO_2 / Short Ton**	**kg CO_2 / MMBtu**
Biomass Derived Fuels (Solid), Wood and Wood Waste (12% moisture content) or other solid biomass-derived fuels	25.60	15.38	1,442.62	93.80
Municipal Solid Waste (MSW)	24.74	8.7	788.7	90.65
Biomass-derived Fuels (Gas)	**kg C / MMBtu**	**Btu / Standard cubic foot**	**kg CO_2 / Standard cubic ft.**	**kg CO_2 / MMBtu**
Biogas*	28.4	Varies	Varies	104.06

Note: Heat content factors are based on higher heating values (HHV).

* The emission factors for biogas include both the CO_2 from combustion and the pass-through CO_2, which are assumed to be in equal proportions.

Source: U.S. EPA, *Inventory of Greenhouse Gas Emissions and Sinks: 1990-2005* (2007), Annex 2.1, Tables A-28, A-31, A-32, A-35, and A-36, except: Heat Content factors for Unspecified Coal (by sector), Coke, Naphtha (<401 deg. F), and Other Oil (>401 deg. F) (from U.S. Energy Information Administration, *Annual Energy Review 2005* (2006), Tables A-1, A-4, and A-5); Heat Content factors for Coal (by type) and LPG and all factors for Wood and Wood Waste, Landfill Gas, and Wastewater Treatment Biogas (from EPA Climate Leaders, Stationary Combustion Guidance (2004), Tables B-1 and B-2). MSW from Energy Information Administration, http://www.eia.doe/gov/oiaf/1605/factors.html and from California Air Resources Board, MSW California Air Resources Board, 2008.

Table 5. Default Carbon Dioxide Emission Factors from Stationary Combustion by Fuel Type for Waste Derived Fuels	
Fuel Type	**kg CO_2 / MMBtu**
Waste Oil	78
Tires	90
Plastics	79
Solvents	78
Impregnated Saw Dust	79
Other Fossil Based Wastes	84
Dried Sewage Sludge	116
Mixed Industrial Waste	88
Municipal Solid Waste	91
Note: Emission factors are based on higher heating values (HHV). Values were converted from LHV to HHV assuming that LHV are 5 percent lower than HHV for solid and liquid fuels.	
Source: WBCSD/WRI, *The Cement CO_2 Protocol: CO_2 Accounting and Reporting Standard for the Cement Industry* Calculation Tool (2004), except: Municipal Solid Waste, (from EIA *Voluntary Reporting of Greenhouse Gases Website* http://www.eia.doe.gov/oiaf/1605/coefficients.html (Accessed October 5, 2007))	

(b) Methane and Nitrous Oxide Emission Factors for Stationary Combustion

The default methane and nitrous oxide emission factors for stationary combustion in Table 6 are provided for use with section 95125(b) of the regulation. For readability, these emission factors are provided in units of grams/MMBtu, but should be converted to kg/MMBtu (i.e., divided by 1000) when using them in the equations in section 95125(b).

Table 6. Default CH_4 and N_2O Emission Factors from Stationary Combustion by Fuel Type

Fuel Type	Default CH_4 Emission Factor (g CH_4/ MMBtu)	Default N_2O Emission Factor (g N_2O / MMBtu)
Asphalt	3.0	0.6
Aviation Gasoline	3.0	0.6
Coal	10.0	1.5
Crude Oil	3.0	0.6
Derived Gases (low Btu gases)	0.3	0.1
Digester Gas	0.9	0.1
Distillate	3.0	0.6
Gasoline	3.0	0.6
Jet Fuel	3.0	0.6
Kerosene	3.0	0.6
Landfill Gas	0.9	0.1
LPG	1.0	0.1
Lubricants	3.0	0.6
MSW	30.0	4.0
Naphtha	3.0	0.6
Natural Gas	0.9	0.1
Natural Gas Liquids	3.0	0.6
Other Biomass	30.0	4.0
Petroleum Coke	3.0	0.6
Propane	1.0	0.1
Refinery Gas	0.9	0.1
Residual Fuel Oil	3.0	0.6
Tires	3.0	0.6
Waste Oil	30.0	4.0
Waxes	3.0	0.6
Wood (Dry)	30.0	4.0

Notes: Heat content factors are based on higher heating values (HHV). Values were converted from LHV to HHV assuming that LHV are 5 percent lower than HHV for solid and liquid fuels and 10 percent lower for gaseous fuels. Those employing this table are assumed to fall under the IPCC definitions of the "Energy Industry" or "Manufacturing Industries and Construction". In all fuels except for coal the values for these two categories are identical. For coal combustion, those who fall within the IPCC "Energy Industry" category may employ a value of 1 g of CH_4/MMBtu.

Source: Intergovernmental Panel on Climate Change, *2006 IPCC Guidelines for National Greenhouse Gas Inventories* (2006), Volume 2, Tables 2.2, 2.3, and 2.4.

(c) Carbon Dioxide Emission Factors for Transportation Fuels

The default carbon dioxide emission factors in Table 7 are provided for use with section 95125(i) of the regulation. These factors may only be used for vehicular emissions and should not be applied to stationary combustion sources.

Table 7. Carbon Dioxide Emission Factors for Transportation Fuels

Fuel	kg CO_2/gallon
Aviation gasoline	8.24
Biodiesel	9.52
CA Low Sulfur Diesel	9.96
CA Reformulated gasoline, 5.7% ethanol	8.55
Crude Oil	10.14
Non-CA Diesel/Diesel No.2	10.05
Ethanol (E85)	6.10
Fischer-Tropsch Diesel	9.13
Jet Fuel, Kerosene (Jet A or A-1)	9.47
Jet Fuel, Naphtha (Jet B)	9.24
Kerosene	9.67
Liquefied Natural Gas (LNG)	4.37
Liquefied Petroleum Gas (LPG)	5.92
Methanol	4.10
Motor Gasoline (Non-CA and off-road)	8.78
Propane	5.67
Residual Oil	11.67
Fuels With Other Units Of Measure	
Natural Gas (CNG) per therm	5.28
Natural Gas (CNG) per gasoline gallon equivalent	6.86
Hydrogen per kg	0.00
Note: Emission factors are based on complete combustion and high heating value (HHV).	
Source: California Energy Commission, *Inventory of California Greenhouse Gas Emissions and Sinks: 1990-1999* (November 2002); Energy Information Administration, *Emissions of Greenhouse Gases in the United States 2000*, (2001), Table B1, page 140, see http://www.eia.doe.gov/oiaf/1605/ggrpt; propane and butane emission factors and fractions oxidized from U.S. Environmental Protection Agency, *Compilation of Air Pollutant Emission Factors, AP-42*, Fifth Edition, see http://www.epa.gov/ttn/chief/ap42/index.html. Methanol emission factor is calculated from the properties of the pure compounds; the fraction oxidized is assumed to be the same as for other liquid fuel.	

(d) Methane and Nitrous Oxide Emission Factors for On-Road Mobile Sources

The default methane and nitrous oxide emission factors in Table 8 are provided for use with section 95125(i) of the regulation.

Table 8. Methane and Nitrous Oxide Emission Factors for Mobile Sources by Vehicle and Fuel Type

Vehicle Types/Model Years	CH_4 (g/mile)	N_2O (g/mile)
Passenger Cars - Gasoline		
Model Year 1984-1993 and older	0.0704	0.0647
Model Year 1994	0.0531	0.0560
Model Year 1995	0.0358	0.0473
Model Year 1996	0.0272	0.0426
Model Year 1997	0.0268	0.0422
Model Year 1998	0.0249	0.0393
Model Year 1999	0.0216	0.0337
Model Year 2000	0.0178	0.0273
Model Year 2001	0.0110	0.0158
Model Year 2002	0.0107	0.0153
Model Year 2003	0.0114	0.0135
Model Year 2004	0.0145	0.0083
Model Year 2005 - present	0.0147	0.0079
Passenger Cars - Alternative Fuels and Diesel		
Methanol	0.018	0.067
CNG	0.737	0.050
LPG	0.037	0.067
Ethanol	0.055	0.067
Diesel Model Year 1960-1982	0.0006	0.0012
Diesel Model Year 1983-present	0.0005	0.0010
Light Duty Truck (Vans, Pickup Trucks, SUVs) Gasoline		
Model Year 1987-1993 and older	0.0813	0.1035
Model Year 1994	0.0646	0.0982
Model Year 1995	0.0517	0.0908
Model Year 1996	0.0452	0.0871
Model Year 1997	0.0452	0.0871
Model Year 1998	0.0391	0.0728
Model Year 1999	0.0321	0.0564
Model Year 2000	0.0346	0.0621
Model Year 2001	0.0151	0.0164
Model Year 2002	0.0178	0.0228
Model Year 2003	0.0155	0.0114
Model Year 2004	0.0152	0.0132
Model Year 2005 - present	0.0157	0.0101

Source: Gasoline vehicle factors from EPA Climate Leader, Mobile Combustion Guidance (2008) based on U.S. EPA, *Inventory of U.S. Greenhouse Gas Emission and Sinks: 1990-2005 (2007)*. Diesel vehicle factors based on U.S. EPA, *Inventory of U.S. Greenhouse Gas Emission and Sinks: 1990-2005 (2007)*, Annex 3.2, Table A-99. Alternative fuel vehicle factors based on U.S. EPA, *Inventory of U.S. Greenhouse Gas Emission and Sinks: 1990-2005 (2007)*, Annex 3.2, Table A-100.

Table 8. Methane and Nitrous Oxide Emission Factors for Mobile Sources by Vehicle and Fuel Type (continued)		
Light Duty Truck - Alternative Fuels and Diesel	**CH_4 (g/mile)**	**N_2O (g/mile)**
Methanol	0.018	0.067
CNG	0.737	0.050
LPG	0.037	0.067
Ethanol	0.055	0.067
Diesel Model Year 1960-1982	0.0011	0.0017
Diesel Model Year 1983-1995	0.0009	0.0014
Diesel Model Year 1996-present	0.0010	0.0015
Heavy-Duty Vehicle - Gasoline		
Model Year 1985 -1986 and older	0.4090	0.0515
Model Year 1987	0.3675	0.0849
Model Year 1988-1989	0.3492	0.0933
Model Year 1990-1995	0.3246	0.1142
Model Year 1996	0.1278	0.1680
Model Year 1997	0.0924	0.1726
Model Year 1998	0.0641	0.1693
Model Year 1999	0.0578	0.1435
Model Year 2000	0.0493	0.1092
Model Year 2001	0.0528	0.1235
Model Year 2002	0.0546	0.1307
Model Year 2003	0.0533	0.1240
Model Year 2004	0.0341	0.0285
Model Year 2005-present	0.0326	0.0177
Heavy Duty Trucks - Diesel and Alternative Fuels		
Methanol	0.066	0.175
CNG	1.966	0.175
LNG	1.966	0.175
LPG	0.066	0.175
Ethanol	0.197	0.175
Diesel All Model Years	0.0051	0.0048
Motorcycles		
Model Year 1996 and older	0.0899	0.0887
Model Year 1996-present	0.0672	0.0669

Source: Gasoline vehicle factors from EPA Climate Leader, Mobile Combustion Guidance (2008) based on U.S. EPA, *Inventory of U.S. Greenhouse Gas Emission and Sinks: 1990-2005 (2007)*. Diesel vehicle factors based on U.S. EPA, *Inventory of U.S. Greenhouse Gas Emission and Sinks: 1990-2005 (2007)*, Annex 3.2, Table A-99. Alternative fuel vehicle factors based on U.S. EPA, *Inventory of U.S. Greenhouse Gas Emission and Sinks: 1990-2005 (2007)*, Annex 3.2, Table A-100.

(e) Fugitive Carbon Dioxide Emission Factor from Geothermal Power Plants

The default carbon dioxide emission factor for geothermal power plants given in Table 9 is provided for use with section 95111(i) of the regulation.

Table 9. Default Fugitive Carbon Dioxide Emission Factor from Geothermal Power Plants

Fuel Type	kg CO_2 / MMBtu
Geothermal	7.53

Source: Energy Information Administration, *Electric Power Annual with data for 2005*, carbon dioxide uncontrolled emission factors website see http://www.eia.doe.gov/cneaf/electricity/epa/epata3.html (Accessed 10/9/07)

(f) Fugitive Emission Factors for Coal Storage

The emission factors for fugitive methane emissions from coal storage in Table 10 are derived from the U.S. EPA Coal Bed Methane Emissions Estimates Database. These factors must be applied as indicated in section 95125(j) of the regulation.

Table 10. Default Fugitive Methane Emission Factors from Post-Mining Coal Storage and Handling (CH_4 ft^3 per Short Ton)

Coal Origin		Coal Mine Type	
Coal Basin	**States**	**Surface Post-Mining Factors**	**Underground Post-Mining Factors**
Northern Appalachia	Maryland, Ohio, Pennsylvania, West Virginia North	19.3	45.0
Central Appalachia (WV)	Tennessee, West Virginia South	8.1	44.5
Central Appalachia (VA)	Virginia	8.1	129.7
Central Appalachia (E KY)	East Kentucky	8.1	20.0
Warrior	Alabama, Mississippi	10.0	86.7
Illinois	Illinois, Indiana, Kentucky West	11.1	20.9
Rockies (Piceance Basin)	Arizona, California, Colorado, New Mexico, Utah	10.8	63.8
Rockies (Uinta Basin)		5.2	32.3
Rockies (San Juan Basin)		2.4	34.1
Rockies (Green River Basin)		10.8	80.3
Rockies (Raton Basin)		10.8	41.6
N. Great Plains	Montana, North Dakota, Wyoming	1.8	5.1
West Interior (Forest City, Cherokee Basins)	Arkansas, Iowa, Kansas, Louisiana, Missouri, Oklahoma, Texas	11.1	20.9
West Interior (Arkoma Basin)		24.2	107.6
West Interior (Gulf Coast Basin)		10.8	41.6
Northwest (AK)	Alaska	1.8	52.0
Northwest (WA)	Washington	1.8	18.9

Source: *Inventory of U.S. Greenhouse Gas Emissions and Sinks:1990 – 2005*

April 15, 2007, U.S. Environmental Protection Agency. Annex 3, Methodological Descriptions for Additional Source or Sink Categories, Section 3.3, Table A-115, Coal Surface and Post-Mining CH4 Emission Factors (ft^3 per Short Ton). (Only Post-Mining EFs used from Table). State assignments shown from Table 113 of Annex 3.

(g) Coke Burn Rate Material Balance and Conversion Factors

The coke burn rate material balance and conversion factors given in Table 11 are provided for use with section 95113(b)(1)(A) of the regulation.

Table 11. Coke burn rate material balance and conversion factors

-	(kg min)/(hr dscm %)	(lb min)/(hr dscf %)
K_1	0.2982	0.0186
K_2	2.0880	0.1303
K_3	0.0994	0.0062

Source: US EPA Title 40 CFR 63.1564

(h) Methane and Nitrous Oxide Emission Factors for Wastewater Treatment

The method to derive an emission factor for fugitive methane and nitrous oxide emissions from wastewater treatment specified below is based on 2006 IPCC guidelines. This method is provided for use with section 95113(c)(1)(A)-(B) of the regulation.

Table 12. Default MCF Values for Industrial Wastewater

Type of Treatment and Discharge Pathway or System	Comments	MCF	Range
Untreated			
Sea, river and lake discharge	Rivers with high organic loading may turn anaerobic, however this is not considered here	0.1	0—0.2
Treated			
Aerobic treatment plant	Well maintained, some CH4 may be emitted from settling basins	0	0—0.1
Aerobic treatment plant	Not well maintained, overloaded	0.3	0.2—0.4
Anaerobic digester for sludge	CH_4 recovery not considered here	0.8	0.8—1.0
Anaerobic reactor	CH_4 recovery not considered here	0.8	0.8—1.0
Anaerobic shallow lagoon	Depth less than 2 meters	0.2	0—0.3
Anaerobic deep lagoon	Depth more than 2 meters	0.8	0.8—1.0

Source: Intergovernmental Panel on Climate Change, *2006 IPCC Guidelines for National Greenhouse Gas Inventories* (2006), Volume 5, Waste, Chapter 6: Wastewater Treatment and Discharge. Prepared by the National Greenhouse Gas Inventories Programme, Eggleston H.S., Buendia L., Miwa K., Ngara T. and Tanabe K. (eds).

MCF = methane correction factor – the fraction of waste treated anaerobically

B = CH_4 generation capacity (kg CH_4/kg COD)
Default factor = 0.25 kg CH_4/kg COD

COD = chemical oxygen demand (kg COD/m^3)

Emission factor for N_2O from discharged wastewater
EF_{N2O} = 0.005 kg N_2O-N/kg-N

(i) Emission Factors for Oil/Water Separators

Use Table 13 to derive emission factors for oil/water separators

Table 13. Emission Factors for Oil/Water Separators

Separator Type	Emission factor (EF_{sep})[1] kg NMHC/m^3 wastewater treated
Gravity type - uncovered	1.11e-01
Gravity type - covered	3.30e-03
Gravity type - covered and connected to destruction device	0
DAF[2] of IAF[3] - uncovered	4.00e-03[4]
DAF or IAF - covered	1.20e-04[4]
DAF or Iaf - covered and connected to a destruction device	0

Source: Air pollutant emission estimation methods for E-PRTR reporting by refineries, CONCAWE, Brussels, April 2007, report no. 3/07

1. EFs do not include ethane
2. DAF = dissolved air flotation type
3. IAF = induced air flotation device
4. EFs for these types of separators apply where they are installed as secondary treatment systems

(j) Gas Service Components Fugitive Emission Factors

The information presented in Table 14 is provided for use with section 95113(c)(4) as part of the method to determine fugitive methane emissions from fuel gas systems.

Table 14. Gas Service Components Fugitive Emissions

Component Type / Service Type	Default Zero Factor (kg/hr)	Correlation Equation (kg/hr)	Pegged Factor (kg/hr)	
			10,000 ppmv	100,000 ppmv
	Zf_{i0}	σ_i and β_i	(SV > 9,999) PF_{iP-10}	(SV> 99,999) PF_{iP-100}
Valves (1)	7.8×10^{-6}	$2.27 \times 10^{-6}(SV)^{0.747}$	0.064	0.138
Pump seals (2)	1.9×10^{-5}	$5.07 \times 10^{-5}(SV)^{0.622}$	0.089	0.610
Others (3)	4.0×10^{-6}	$8.69 \times 10^{-6}(SV)^{0.642}$	0.082	0.138
Connectors (4)	7.5×10^{-6}	$1.53 \times 10^{-6}(SV)^{0.736}$	0.030	0.034
Flanges (5)	3.1×10^{-7}	$4.53 \times 10^{-6}(SV)^{0.706}$	0.095	0.095
Open-ended lines (6)	2.0×10^{-6}	$1.90 \times 10^{-6}(SV)^{0.724}$	0.033	0.082

Source: California Implementation Guidelines for Estimating Mass Emissions of Fugitive Hydrocarbon Leaks at Petroleum Facilities, February 1999, California Air Pollution Control Officers Association (CAPCOA) and California Air Resources Board

6. Method for Calculating Emissions of High Global Warming Potential Compounds

Provided below is the fugitive SF_6 emissions calculation methodology created by the U.S. EPA SF_6 Emission Reduction Partnership for Electric Power Systems. Operators shall use this approach or a service log for estimating fugitive emissions of high global warming potential compounds, including SF_6, HFCs, and PFCs, as specified in sections 95111(f) (g) of the regulation. The reporting form that follows the method below is for illustrative purposes. Pounds shall be converted to kilograms for purposes of reporting.

SF6 EMISSIONS INVENTORY REPORTING METHOD AND FORM

This worksheet is based on the **mass-balance method**. The mass-balance method works by tracking and systematically accounting for all operator uses of SF_6 during the reporting year. The quantity of SF_6 that cannot be accounted for is then assumed to have been emitted to the atmosphere. The method has four subcalculations (A-D), a final total (E), and an optional emission rate calculation (F) as follows:

A. **Change in Inventory**. This is the difference between the quantity of SF_6 in storage at the beginning of the year and the quantity in storage at the end of the year. The "quantity in storage" includes SF_6 gas contained in cylinders (such as 115-pound storage cylinders), gas carts, and other storage containers. It does not refer to SF_6 gas held in operating equipment. The change in inventory will be negative if the quantity of SF_6 in storage increases over the course of the year.

B. **Purchases/Acquisitions of SF_6**. This is the sum of all the SF_6 acquired from other entities during the year either in storage containers or in equipment.

C. **Sales/Disbursements of SF_6**. This is the sum of all the SF_6 sold or otherwise disbursed to other entities during the year either in storage containers or in equipment.

D. **Change in Total Nameplate Capacity of Equipment**. This is the net increase in the total volume of SF_6-using equipment during the year. Note that "total nameplate capacity" refers to the full and proper charge of the equipment rather than to the actual charge, which may reflect leakage. This term accounts for the fact that if new equipment is purchased, the SF_6 that is used to charge that new equipment should not be counted as an emission. On the other hand, it also accounts for the fact that if the amount of SF_6 recovered from retiring equipment is less than the nameplate capacity, then the difference between the nameplate capacity and the recovered amount has been emitted. This quantity will be negative if the retiring equipment has a total nameplate capacity larger than the total nameplate capacity of the new equipment.

E. **Total Annual Emissions**. This is the total amount of SF_6 emitted over the course of the year, based on the information provided above. The amount is presented both in pounds of SF_6 and in metric tonnes of CO_2 equivalent, that is, the quantity of carbon dioxide emissions that would have the same impact on the climate as the quantity of SF_6 emitted. Because SF_6 has 23,900 times the ability of carbon dioxide to trap heat in the atmosphere on a pound-for-pound basis, 1 pound of SF_6 is equivalent to nearly 11 metric tonnes of carbon dioxide.

~~F. **Emission Rate (optional).** By providing the total nameplate capacity of all the electrical equipment in your facility at the end of the year, you can obtain an estimate of the emission rate of your facility's equipment (in percent per year).~~
~~The emission rate is equal to the total annual emissions divided by the total nameplate capacity.~~

SF_6 Emissions Reduction Partnership for Electric Power Systems

Annual Reporting Form

Name:		Company Name:	
Title:		Report Year:	
Phone:		Date Completed:	

Decrease in Inventory (SF_6 contained in cylinders, not electrical equipment)

Inventory (in cylinders, not equipment)	AMOUNT (lbs.)	Comments
1. Beginning of Year		
2. End of Year		
A. Decrease in Inventory (1 - 2)		

Purchases/Acquisitions of SF_6

	AMOUNT (lbs.)	Comments
3. SF_6 purchased from producers or distributors in cylinders		
4. SF_6 provided by equipment manufacturers with/inside equipment		
5. SF_6 returned to the site after off-site recycling		
B. Total Purchases/Acquisitions (3+4+5)		

Sales/Disbursements of SF_6

	AMOUNT (lbs.)	Comments
6. Sales of SF_6 to other entities, including gas left in equipment that is sold		
7. Returns of SF_6 to supplier		
8. SF_6 sent to destruction facilities		
9. SF_6 sent off-site for recycling		
C. Total Sales/Disbursements (6+7+8+9)		

Increase in Nameplate Capacity

	AMOUNT (lbs.)	Comments
10. Total nameplate capacity (proper full charge) of new equipment		
11. Total nameplate capacity (proper full charge) of retired or sold equipment		
D. Increase in Capacity (10 - 11)		

Total Annual Emissions

	lbs. SF_6	kgs. SF6	Tonnes CO_2 equiv.
E. Total Emissions (A+B-C-D) (lbs.)			

Emission Rate (optional)

	AMOUNT (lbs.)	Comments
Total Nameplate Capacity at End of Year		
	PERCENT (%)	
F. Emission Rate (Emissions/Capacity)		