Decision 14-12-037 December 18, 2014

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Address Utility Cost and Revenue Issues Associated with Greenhouse Gas Emissions.	Rulemaking 11-03-012 (Filed March 24, 2011)

DECISION ADOPTING GREENHOUSE GAS ALLOWANCE REVENUE ALLOCATION FORMULAS AND DISTRIBUTION METHODOLOGIES FOR EMISSIONS-INTENSIVE AND TRADE-EXPOSED CUSTOMERS

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DECISION ADOPTING GREENHOUSE GAS ALLOWANCE REVENUE ALLOCATION FORMULAS AND DISTRIBUTION METHODOLOGIES FOR EMISSIONS-INTENSIVE AND TRADE-EXPOSED CUSTOMERS

1. Summary

In accordance with the California Global Warming Solutions Act of 2006, Assembly Bill 32 (AB 32) and California Public Utilities Code Section 748.5, this decision adopts the greenhouse gas (GHG) allowance revenue allocation formulas and distribution methodologies for emission-intensive and trade-exposed (EITE) customers, as those customers are defined in Decision 12-12-033. These formulas and methodologies are to be employed by California's investor-owned electric utilities,[1] with the exception of Bear Valley Electric Service. The adopted formulas are located in Appendix A to this decision.

In addition, this decision addresses certain factors necessary to distribute GHG revenue to EITE customers, including the timing of the distribution, confidentiality provisions, and the methodology by which GHG allowance revenue will be distributed to EITE entities with annual emissions less than 25,000 metric tons carbon dioxide equivalent.

This proceeding remains open.

[1] The investor-owned utilities (IOUs) include Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), San Diego Gas and Electric Company (SDG&E), Liberty Utilities (formerly California Pacific Electric Company), and PacifiCorp. Bear Valley Electric Company, a division of Golden State Water Company, was exempted from the distribution methodologies adopted in D.12-12-033 due to the small amount of GHG revenues it will receive.

2. Background and Procedural History

Under the California Air Resources Board's (ARB) economy-wide greenhouse gas (GHG) Cap-and-Trade program,[2] the first phase of which became effective January 1, 2012, ARB annually grants the state's investor-owned electric utilities an allocation of GHG allowances, which the utilities are required to sell in ARB's quarterly allowance auctions. These mandatory allowance sales generate substantial revenue that "must be used exclusively for the benefit of retail ratepayers of…electric distribution [utilities], consistent with the goals of AB 32,"[3] the Global Warming Solutions Act of 2006.[4] ARB prohibits investor-owned electric utilities from using these allowances to address their compliance obligations under Cap-and-Trade. The Commission established a proceeding, Rulemaking (R.) 11-03-012, to address the various policy questions that arose from ARB's implementation of AB 32, among other issues. In Decision (D.) 12-12-033 the Commission adopted a framework of rules regarding how the investor-owned electric utilities should distribute allowance revenue in accordance with ARB's Cap-and-Trade regulation and the parameters of Public Utilities (Pub. Util.) Code Section 748.5.[5]

Section 748.5 of the Public Utilities Code requires the Commission to provide a direct return of electric utility allowance revenue to residential, "small business," and "emissions-intensive and trade-exposed" (EITE) entities. For the

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[2] California Cap on GHG Emissions and Market-Based Compliance Mechanisms, Title 17, California Code of Regulations, Sections 95801-96022.

[3] *Id. at* § 95892.

[4] Statutes of 2006, Chapter 488.

[5] All future references to code sections shall pertain to the California Public Utilities Code, unless otherwise noted.

purposes of allocating GHG allowance revenue, D.12-12-033 defined small businesses as non-residential electricity customers with a monthly electricity demand that does not exceed 20 kilowatts in more than three months within a twelve-month period.[6] It also applied a statutory construction of the term "emissions-intensive and trade-exposed" to mean those entities in industrial sectors that qualify for Industry Assistance under ARB's Cap-and-Trade regulation, regardless of the amount of emissions produced. These industries are explicitly listed by North American Industry Classification System (NAICS) Code in ARB's Cap-and-Trade regulation.[7]

In addition, in D.12-12-033 the Commission found that entities with annual emissions levels less than 25, 000 metric tons of carbon dioxide equivalent gas ($MTCO_2e$) that operate in sectors eligible for Industry Assistance should be designated as EITE and "must voluntarily opt in to the Cap-and-Trade program, unless another suitable method can be found to accurately obtain the necessary information to calculate revenue returns for these customers."[8] The Decision allowed staff and parties to evaluate whether there are effective ways to allow these particular entities to receive an allocation of allowance revenue without opting in to the Cap-and-Trade program.[9]

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[6] D.12-12-033, COL 11.

[7] *See* D.12-12-033 FOF 63, COL 2 and 13. *See* also 17 CCR § 95870 *et seq*. and industries listed by NAICS Code in *Table 8-1: Industry Assistance.*

[8] D.12-12-033, FOF 58. ARB's Industry Assistance only applies to facilities that directly emit 25,000 $MTCO_2e$ or more emissions in a year (i.e. "covered entities") unless a facility with emissions below that threshold opts-in to the Cap-and-Trade regulation.

[9] *Id.* at 151; FOF 58; COL 14; COL 68; OP 6.

2.1. Procedural History

Though D.12-12-033 defined a list of industries that qualify as EITE, and established a framework for the distribution of GHG allowance revenues to those customers based as closely as practicable on ARB's methodologies for allocating allowances for Industry Assistance, the Commission deferred several implementation details to later decisions. In particular, the Commission sought additional information in order to finalize the formulas and associated processes to distribute GHG allowance revenue to small business and EITE customers.[10]

In Appendices A and B to D.12-12-033, the Commission proposed formulas to allocate GHG allowance revenue to EITE and small business customers. The Commission also directed its staff to initiate a public workshop process to: evaluate the proposed formulas and methodologies; identify required data input sources for these methodologies; identify timing of information and data exchanges that must occur to calculate the revenue return; evaluate the timing and form of the GHG revenue distribution; and explore alternatives to the requirement to opt-in to the Cap-and-Trade program for EITE entities with emissions less than 25,000 MTCO2e.[11]

On January 23, 2013, the Administrative Law Judge (ALJ) issued a ruling announcing a technical workshop and soliciting pre-workshop comments on the methodologies proposed in Appendices A and B to the D.12-12-033, which were received on February 6, 2013. On February 14 and 15, 2013, Commission staff facilitated a technical workshop and on May 20, 2013, served a draft staff

[10] *Id.* at FOF 85 and 86.

[11] *Id.* at OP 25.

proposal (Staff Proposal) presenting updated revenue distribution formulas and methodologies on the service list for this rulemaking.

On June 7, 2013, staff held a public workshop to discuss the draft Staff Proposal. Via a July 10, 2013 ruling, the ALJ incorporated the final Staff Proposal, entitled *Greenhouse Gas Revenue Allocation Methodologies for Emissions-Intensive and Trade-Exposed Entities and Small Businesses*, into the record of R.11-03-012.[12] On July 24, 2013, numerous parties filed comments on the Staff Proposal.[13]

On October 16, 2013, the ALJ issued a ruling presenting an update to the Staff Proposal, which recommended a method to prevent the disclosure of confidential business information about individual EITE entities. Opening comments were filed on October 30, 2013 by CMTA, the Large Users, SDG&E, PG&E, and SCE (jointly). No reply comments were received.

At its April 25, 2014 board meeting, ARB certified revisions to its Cap-and-Trade Regulation that affect how it allocates allowances for Industry Assistance. These changes were approved by the California Office of Administrative Law on June 26, 2014.

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[12] The Staff Proposal is available at http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M071/K162/71162253.PDF.

[13] Parties submitting comments on the Staff Proposal were: the California Cogeneration Council (CCC), The California Farm Bureau Federation, The California League of Food Processors (Food Processors), The California Manufacturers and Technology Association (CMTA), Gerdau Long Steel North America (Gerdau), the "Joint Parties" (including the Natural Resources Defense Council, The Greenlining Institute, Sierra Club California, Climate Protection Campaign, and National Consumer Law Center, the "Joint Utilities" (PG&E, SCE, and SDG&E), the Large Users (CMTA, the Energy Producers and Users Coalition, and the California Large Energy Consumers Association), Marin Energy Authority (MEA), Office of Ratepayer Advocates (ORA), Tesoro Refining and Marketing Company, LLC (Tesoro), and USS-POSCO.

In D.13-12-003, issued on December 12, 2013, the Commission adopted a GHG revenue distribution formula and methodology for small business customers. Today's decision addresses the GHG revenue distribution formulas and methodologies for EITE customers, as well as circumstances in which a customer may have accounts that qualify as both an EITE and small business customer.

3. Industry Assistance under the ARB Cap-and-Trade Regulation and Commission Direction in D.12-12-033

Today's decision addresses the GHG revenue allocation necessary to provide transition assistance to mitigate the risk that industrial production and GHG emissions could shift (i.e. leak) out of California. Appendix A to D.12-12-033 set forth preliminary formulas to determine the amount of GHG allowance revenue each qualifying industrial entity and small business should receive.[14] The formulas and implementation details contained in the Staff Proposal build upon the appendices to D.12-12-033 and are substantially based on similar methodologies developed by ARB to determine what amount of free allowances industrial entities are eligible to receive to address their direct emissions costs.[15]

ARB provides Industry Assistance to certain industrial sectors covered by the Cap-and-Trade program to address leakage risk and to provide transition assistance to help phase in exposure to a carbon price signal. This Industry Assistance consists of an allocation of allowances to cover a percentage of an

[14] D.12-12-033 at FOF 84-101.

[15] *See* ARB's Initial Statement of Reasons (ISOR) Appendix J.

industrial entity's direct emissions (emissions from on-site activities) as well as emissions associated with heat imported from offsite.[16]

As discussed in D.12-12-033 and ARB's regulations, the introduction of an environmental regulation in one jurisdiction can cause production costs and prices in that jurisdiction to increase relative to costs in jurisdictions that do not have comparable regulations. This can precipitate a shift in demand away from goods produced in the implementing jurisdiction toward goods produced elsewhere. As a result, the reduction in production and emissions in the implementing jurisdiction is offset by increased production and emissions elsewhere.[17] This shift in production and offsetting increase in emissions is considered "leakage." To prevent leakage, ARB directly allocated allowances to certain at-risk industries. This Industry Assistance[18] has the effect of reducing an industrial entity's cost of complying with the Cap-and-Trade program while maintaining the integrity of the statewide GHG emissions cap and preserving incentives for facilities to operate efficiently and to reduce emissions. These allowances also provide transition assistance: by reducing the near-term cost of complying with the Cap-and-Trade program, ARB preserves an entity's ability to invest in measures (e.g. energy efficiency; fuel switching) that can reduce its exposure to GHG costs, thus helping the entity to transition to the current paradigm of carbon pricing.

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[16] ARB ISOR Appendix J at 32 and ARB Cap-and-Trade Regulation at Section 95870(e) and Section 95891.

[17] ARB ISOR Appendix J at 18; D.12-12-033 at 17.

[18] For ARB's eligibility and implementation rules, see Cap and Trade Regulation § 95870(e) and § 95891.

ARB identified which industrial sectors qualify for Industry Assistance by conducting a study that classified industries by high, medium or low leakage risk.[19] This analysis evaluated the emissions intensity and the trade share of certain manufacturing and resource extraction industries. The scope of this study was limited to industrial sectors in which at least one entity had a direct compliance obligation under the Cap-and-Trade Regulation (i.e. an entity that annually emits more than 25,000 $MTCO_2e$). ARB studied industries that had high levels of direct emissions – those emissions associated with on-site fuel combustion and steam purchases. However, as described earlier in this decision, in D.12-12-033 the Commission concluded that any facility in an industry that qualifies for ARB's Industry Assistance should also receive allowance revenue to address GHG costs present in their electricity purchases.

Though ARB's Industry Assistance only covers an industry's *direct* emissions, ARB's analysis of industrial leakage risk took into consideration an industry's *total* emissions – including both direct and indirect emissions.[20] As a result, ARB's assignment of leakage risk – high, medium, or low, for each industry – is relevant in the context of D.12-12-033 because that assessment of leakage risk included indirect emissions associated with electricity purchases.

In D.12-12-033, the Commission explained that there may be industries that are not directly covered by the Cap-and-Trade program or designated by ARB to be eligible for Industry Assistance, but that have high levels of electricity purchases and trade pressures.[21] In D.14-02-003 the Commission adopted a

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[19] *See* ARB ISOR, Appendix K and Cap-and-Trade Regulation § 95870, Table 8-1.

[20] ARB ISOR Appendix K at 10.

[21] D.12-12-033 at 86.

framework and budget to study this issue and to consider potentially expanding the list of industries that should be designated as "EITEs." D.14-02-003 stopped short of adopting any particular GHG revenue allocation methodology for such industries. It determined that a thorough study should be completed before addressing whether new industries should be eligible and what revenue allocation methodologies would apply. However, the Commission does not currently have budget authority to conduct this study, so the study remains on hold until the Commission has such authority.

ARB uses three different methodologies to allocate allowances for Industry Assistance: a product-based allocation, an energy-based allocation, and a refinery allocation.

3.1. Product-Based Allocation Methodology

ARB's preferred method of allocating allowances for Industry Assistance is via emissions intensity product benchmarks that represent each industry's average emissions released per unit of product output. Benchmarking allows ARB to compare the relative GHG emissions intensity of a given entity to a common industry standard. This method rewards facilities that have taken early action to reduce emissions and ensures that industries have a strong incentive to produce products in the most GHG-efficient way possible.[22]

Under a product-based benchmark approach, ARB allocates allowances to industrial entities as a function of the industrial sector-wide GHG emissions released per unit of product output. ARB's GHG emissions intensity benchmarks are specific to each industrial sector and are calculated based on

[22] ARB ISOR Appendix J at 11, 26.

total sector-wide emissions divided by total product output during a given historical period, taking into account only those entities that have a compliance obligation. Product-based benchmarks are calculated once at the outset of the program and are not updated regularly over time. They are listed explicitly for each industry in Table 9-1 of ARB's Cap-and-Trade Regulation.[23] In general, when calculating product-based benchmarks, ARB relied on a historical period of 2008-2010, with some variability in instances when different data were necessary to establish a baseline benchmark.

Though industry emissions intensity benchmarks remain fixed, an individual facility's annual allocation of allowances will vary depending on the facility's annual product output. This approach ensures that industrial facilities are compensated in proportion to actual emissions produced, which may vary significantly year by year with variations in product output. Product-based allocation also ensures that a facility that is more efficient than the benchmark will have an economic advantage over a facility that is less efficient than the benchmark. Inefficient facilities will have to acquire a greater amount of additional allowances beyond those freely allocated – either at auction or in a secondary market for allowances.[24]

3.2. Energy-Based Allocation Methodology

Under its energy-based allocation methodology, ARB calculates a benchmark based on the historical annual arithmetic mean emissions from a given covered entity based on a historical period of 2008-2010, with some variability in instances when different data were necessary to establish a baseline

[23] 17 CCR § 95890, Table 9-1: Product-Based Emissions Efficiency Benchmarks.

[24] ARB ISOR Appendix J at 21.

benchmark or when historical data were unavailable. While a product-based benchmark applies equally to all entities in a specific industrial sector, ARB's energy-based benchmarks are facility-specific. Energy-based benchmarks are also not tied to a facility's annual product output, nor are they tied to variations in a facility's ongoing energy use.

ARB uses an energy-based allocation methodology for sectors in which a product-based approach has not yet been developed or is not technically feasible, for example, when there is too much heterogeneity among products made by a single sector. Some sectors have relatively simple and uniform products and processes (e.g., cement), whereas others have a wide range of products (e.g., the food manufacturing sector) that make it difficult to calculate a uniform benchmark for the sector. Though certain sectors do not currently have a product-based benchmark, ARB staff has the ability to continue working with sectors to define a product-based benchmark and to transition a sector from the energy-based allocation to a product-based allocation via Cap-and-Trade Regulation amendments.[25]

ARB characterizes the use of an energy-based benchmark as a "fallback" approach.[26]

3.3. Refinery Allocation

ARB's refinery allocation methodology for the first Cap-and-Trade compliance period uses a two-tiered approach to allocate revenue to individual refineries. ARB first allocates allowances to the refinery sector as a whole by

[25] ARB's April 2014 Cap-and-Trade Regulation amendments include new and revised product benchmarks.

[26] ARB ISOR Appendix J at 50.

using the product-based benchmarking methodology. This sector-wide allocation reflects changes in total refinery output from year to year. After allocating allowances to the refinery sector, ARB apportions allowances to each refinery based on the complexity of the refinery. For simple refineries, ARB allocates allowances based on a simple-barrel product-benchmark. For complex refineries, which comprise approximately 90% of refinery capacity in California, ARB allocates allowances based on the relative efficiency of each refinery.

Initially, the Cap-and-Trade Regulation required that the refinery allocation methodology discussed above would apply only to the first compliance period (2013-2014) and that ARB would transition to a carbon dioxide weighted tonne (CWT) approach after the first compliance period. However, ARB's recent Cap-and-Trade Regulation amendments (April 25, 2014) rely on a complexity weighted barrel (CWB) methodology for the second and third compliance periods. Now that ARB has chosen a CWB methodology, the Commission will need to revise its own refinery allocation methodology to ensure that the Commission's methodology continues to align with ARB's during the second and third Cap-and-Trade program compliance periods.

4. Adopted Formulas and Distribution Processes

The Commission has previously indicated a preference to closely mirror ARB's Industry Assistance allocation methodologies when distributing GHG allowance revenue to EITE customers. By developing methodologies that closely parallel ARB's, the Commission seeks to minimize administrative burdens for industries and regulators alike in the event that ARB decides at a later date to revise its benchmarking methodologies to include indirect emissions from electricity purchases. Furthermore, ARB's allocation methodologies were established and vetted through a lengthy public process with the participation of

affected industries and interested parties. Accordingly, the formulas and methodologies adopted in this decision mirror ARB's allocation methodologies whenever possible, making exceptions as appropriate to:

- Reflect the fact that the Commission will allocate revenue, rather than allowances, and that benchmarks need to reflect indirect emissions from electricity purchases, rather than direct emissions.[27]
- ARB's methodology presents unworkable complications when applied to emissions from electricity purchases.
- Necessary data are unavailable;
- Legal issues or policy questions exist that ARB did not address in the scope of its regulation.

In particular, we adopt the use of a product-based allocation methodology, with certain exceptions for facilities that have direct emissions less than 25,000 $MTCO_2e$, for industries that currently receive a product-based allocation of allowances from ARB.[28] We also adopt the use of energy and refinery allocation methodologies for those industries that receive direct allowances from ARB according to energy or refinery allocation methodologies. If ARB expands or changes the list of industrial sectors that receive product-based or energy-based allocations, those changes will be reflected in our allocation of revenue to those industries.

Section 4 of this decision, below, addresses the specific formulas we approve for use when distributing GHG allowance revenue to customers designated as EITE. Section 4 focuses first on variables and other considerations

[27] D.12-12-033 at 98-102.

[28] These industries are included in 17 CCR §95891, Table 9-1: Product-Based Emissions Efficiency Benchmarks, as may be modified by ARB from time to time.

that apply to all three allocation methodologies, and then delves into the mechanics of the product-based, energy-based and refinery allocation formulas. The remaining sections address additional policies and processes that must be in place in order to ensure an orderly distribution of allowance revenue to EITE customers. The adopted formulas and processes are contained in Appendix A to this decision.

4.1. Timing of EITE Revenue Distribution

There are two principle questions of timing the Commission must consider when adopting EITE revenue allocation formulas: 1) Should GHG allowance revenue be returned to EITE customers before the facility will begin incurring annual GHG costs through electricity purchases, or should the revenue be given after the year's average allowance prices are known and the facility has incurred GHG costs, and 2) During what month of the year should GHG allowance revenue be returned to EITE customers (i.e. should it coincide with the timing of the residential GHG allowance revenue allocation known as the *California Climate Credit*)? The specific timing during the year for distribution of GHG allowance revenue will be discussed in Section 8.3.

Staff recommends that allowance revenue payments be made in advance "to provide industrial entities with an additional level of transition assistance without any apparent detriment to other classes of ratepayers or threats to the integrity of the Cap-and-Trade Program."[29]

This approach deviates from the Commission's stated preference that EITE allocations should occur "after a given Cap-and-Trade program budget year has

[29] Staff Proposal at 27.

passed."[30] However, the intent behind this Commission preference is to discourage the use of forecasted allowance prices, and this concern can be satisfied by relying on the weighted average clearing price of the most recent year's allowance auctions, with true-ups once actual allowance prices are known. Staff suggests that an advance payment of the allocation would allocate revenue in a timelier manner, and it would benefit eligible industrial entities without any known negative impacts on ratepayers or the Cap-and-Trade program. No party opposes this approach.

An advance payment of allocation revenues will assist EITE customers without any known detriment to other ratepayer groups and is reasonable. Furthermore, a prospective allocation will provide financial certainty for EITE customers and reduce the risk of leakage that could result if EITE entities must cover a year's worth of GHG costs prior to receiving GHG allowance revenue.

All payments of GHG allowance revenue to EITE customers shall be made in advance on an annual basis. We also adopt true-up provisions to account for the difference between the current year's allowance prices and allowance prices from the previous year. If the product-based formula is used, the true-up should also account for differences between past product output and actual product output once it is known. The appropriate true-up variables are defined in Appendix A as Equation 4 for the product-based methodology, Equation 7 and Equation 11 for the energy-based methodology, and Equations 16, 17, 19 and 20 for the refinery methodology.

[30] D.12-12-033 at FOF 92.

4.2. Assistance Factors

Assistance factors represent the level of assistance ARB provides to industries – high, medium or low-based on each industry's leakage risk. In Table 8-1 of ARB's Cap-and-Trade regulation, ARB established these assistance factors based on a leakage risk analysis for each of these industrial activities.[31] This analysis evaluated leakage risk as a result of an industry's total emissions, including direct emissions and indirect emissions from electricity purchases. Even though ARB does not allocate allowances to address GHG costs in electricity rates, its leakage study was conducted in a manner that considered emissions broadly. As a result, the assistance factors developed by ARB are also relevant in the context of the Commission's revenue allocation to address GHG costs in electricity rates. No party opposed the use of ARB-designated assistance factors.

Accordingly, the Commission will use the assistance factors ARB developed for each industrial activity (outlined in Table 8-1 of its Cap-and-Trade Regulation) when distributing GHG allowance revenue to EITE entities. The rate by which the assistance factors for indirect electricity revenue allocations decline over time should also mirror the declines approved by ARB.

ARB Cap-and-Trade Regulation amendments approved in April 2014 include a delay by one compliance period of the date when assistance factors begin to decline. The Commission will reflect this change, and any later changes to ARB's assistance factors, when allocating allowance revenue to EITE customers.

[31] *See* ARB ISOR, Appendix K.

4.3. Dollar Conversion Factor

The dollar conversion factor, *D*, converts metric tons of emissions into dollars. This conversion is necessary because the utilities must allocate GHG allowance revenue, rather than allowances, to industrial facilities; ARB requires the utilities to consign all of their directly granted allowances to auction. Under the approach proposed in Appendix A to D.12-12-033, the dollar conversion factor would be defined as the sales-weighted average market clearing price of allowances sold at ARB's quarterly allowance auctions of the same vintage as the budget year for which compensation is being provided. For example, when allocating revenues to address GHG costs experienced in 2013, the dollar conversion factor should represent the weighted average market clearing price of year 2013-vintage allowances sold in all four of ARB's quarterly allowance auctions in 2013. Based on the results of ARB's 2013 auctions, this value would be $12.77 per $MTCO_2e$.

Staff recommends that the dollar conversion factor calculation only reflect current auctions, not advance auctions, since current auctions more accurately represent GHG costs during each budget year. This recommendation is supported by CCC, the Joint Utilities, and USS-POSCO.

The Large Users and Gerdau disagree, arguing that it would raise competitive neutrality concerns between the utilities and Direct Access (DA) customers and would place DA customers at a competitive disadvantage because auction prices may not reflect a DA customer's actual GHG costs. The Large Users assert that since DA customers will bear carbon costs equivalent to the GHG costs embedded in the wholesale market price of electricity (California Independent System Operator (CAISO) market clearing price), applying staff's proposed calculation could leave EITE customers served by Electricity Service

Providers (ESP) at a risk of leakage because the allowance auction price may understate (or at times overstate) the GHG costs they actually incur. For these reasons, the Large Users (and Gerdau) argue that the Commission should use the GHG price implicit in the CAISO market price as the dollar conversion factor for DA customers.

Allowances are introduced to the market via ARB's auctions, and the bulk of utility compliance procurement is effectively required to occur at ARB's auctions.[32] Though the CAISO GHG index may fluctuate significantly by day, and ARB's auctions occur only quarterly, these two markets should generally follow the same average trends over the course of a year.

Although ARB's auctions better represent each utility's GHG costs, the weighted average of ARB's allowance auctions does not necessarily reflect GHG costs embedded in wholesale electricity prices. We find that CAISO's GHG Allowance Index Price is a more accurate representation of GHG costs per ton embedded in wholesale electricity rates on a day-to-day basis. As Gerdau notes, CAISO has explained that its index "reflects the current cost of procuring an allowance, the replacement cost of using an allowance already held to generate, as well as the opportunity cost of not generating and selling the allowance."[33] CAISO publishes its GHG Allowance Index Price on a daily basis, which captures more information about market movement than the results of quarterly auctions.[34] The dollar conversion factor shall, therefore, be calculated using the

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[32] *See* Decision D.12-04-046, which sets GHG allowance procurement rules for utilities, including limits on hedging activities.

[33] Comments of Gerdau at 4, citing CAISO's *California Greenhouse Gas Cap and Generation Variable Costs, White Paper*, Department of Market Monitoring, 2012.

[34] CAISO's GHG Allowance Index Prices are available at http://oasis.caiso.com.

annual average of CAISO's daily GHG Allowance Index Price. The most recent year's average index price shall be used when calculating returns for the current year. For example, to calculate the 2014 dollar conversion factor, the average of CAISO's daily 2013 GHG index prices will be used. The average of this index in 2013 is $13.56 (a 6.2% difference from the weighted average of ARB's 2013 auctions of 2013 vintage allowances). When the revenue allocation true-up occurs, which for 2014 will occur in 2015, the annual average of CAISO's daily 2014 GHG Allowance Index Price will be used.

4.4. Cap Adjustment Factor

The cap adjustment factor establishes the rate at which California's GHG cap will decline over time. The Staff Proposal recommends that the values used for the cap adjustment factor, *C*, in the Commission's product-based, energy-based and refinery allocation methodologies should exactly match the cap adjustment factors defined in Table 9-2 of ARB's Cap-and-Trade regulation. Table 9-2 defines two series of cap adjustment factors: factors specific to sectors with process emissions greater than 50%, and factors that apply to all other industries.

A limited number of industries – nitrogenous fertilizer manufacturing, cement manufacturing, and lime manufacturing – produce a majority of their emissions as a result of chemical processes associated with the creation of their products, rather than from the direct combustion of fuel. Because these emissions are the result of chemical reactions and there is "no direct method available for reducing the emission intensity of [these] chemical [processes],"[35]

[35] ARB ISOR Appendix J at 40.

ARB defined a cap decline factor specific to these industries, which has a separate rate of decline from the factors applied to all other industries.

The Large Users and Gerdau suggest that electricity usage of the sole entity in the Iron and Steel Mills Sector, the Rancho Cucamonga Mill (operated by Gerdau) should be treated in the same manner that ARB's treats industries with process emissions greater than 50% of total emissions. The Large Users admit that no process emissions are at issue in Gerdau's case, but they nevertheless argue that approximately 50% of Gerdau's "electricity use and indirect emissions are unavoidable due to the constraints of physics in precisely the same way as process emissions."[36]

There is a distinction between unavoidable emissions that result directly from chemical reactions, as is the case with the fertilizer, cement and lime manufacturing industries, and emissions that result from a manufacturing process that requires energy to power its operations, either in the form of fuel or electricity. Gerdau's indirect emissions fall into the latter category – its demand for electricity is no different from another industry that needs electricity to power an industrial process. It would be inappropriate to treat Gerdau differently from other industries, which could demonstrate that a certain minimum amount of energy is necessary to power their operations and make their products. Additionally, the presence of cost-effective emissions abatement opportunities was not factored into ARB's development of its cap adjustment factors; therefore, there exists no compelling reason why the Commission should now take into

[36] Opening Comments of the Large Users at 21.

account an industry's cost-effective emission abatement opportunities when evaluating the reasonableness of ARB's default cap adjustment factors.

The Commission's revenue allocation only addresses GHG costs experienced in electricity rates, not costs associated with process emissions. Therefore, it is inappropriate to use ARB's cap adjustment factors for sectors with process emissions greater than 50% in the Commission's formulas to address indirect GHG costs experienced through electricity rates. ARB treated the energy use portion of direct emissions equivalently across all sectors, and it is reasonable to mirror ARB by treating indirect emissions equivalently across all sectors. The Commission will apply ARB's Cap Adjustment Factor for All Other Direct Allocation (referred to herein as ARB's "default cap adjustment factor") [37] to all industries for their indirect emissions from electricity, including the Iron and Steel Mills sector.

4.5. Emission Factors

ARB allocates allowances to eligible industries based on benchmarks of direct emissions that industrial facilities emit. To establish these benchmarks, ARB converts an industrial facility's energy use into emissions through the use of emission factors. ARB approved several fuel-specific emission factors in its Mandatory Reporting Regulation (MRR) and its Cap-and-Trade Regulation for this purpose, but none directly applies to the circumstance currently before the Commission. ARB established emission factors for electricity exported by on-site generation (e.g. from on-site Combined Heat and Power (CHP) plants that export

[37] *i.e.* the Cap Adjustment Factor for All Other Direct Allocation in Table 9-2 of ARB's Cap and Trade Regulation.

to the grid)[38] and for electricity imported into California from unknown (*i.e.* "unspecified") resources, but has not established emission factors that specifically represent the emissions embedded in electricity that IOUs, CCAs or DA providers sell to end-use customers.

Two primary options exist for calculating emission factors: 1) develop a single statewide emission factor that applies to all sources of electricity purchases (with exceptions for off-site CHP, as we explain below); or 2) develop emission factors specific to each type of electricity provider, whether they are IOUs, publicly owned utilities (POUs) or other non-utility electricity providers like CCAs or DAs. The most administratively simple option is to establish a statewide emission factor that would apply to all electricity purchases. No parties opposed the use of a statewide emission factor in their formal comments, and several recommended the use of a single statewide factor. In their February 6, 2013, comments, the Joint Utilities support the use of an emission factor of 0.431 $MTCO_2e$ for all IOUs. This value is consistent with the value adopted by ARB for electricity that CHP facilities export to the grid.

However, the Staff Proposal notes that the 0.431 $MTCO_2e/MWh$ emission factor is substantially higher than the average portfolio emissions of any single investor-owned utility. In addition, a statewide 0.431 $MTCO_2e/MWh$ emission factor does not take into account the fact that a portion of IOU, CCA and DA providers' electricity consists of zero-emission electricity due to their Renewable Portfolio Standard (RPS) obligations.[39]

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[38] This emissions factor is 0.431 $MTCO_2e/MWh$, and is outlined in 17 CCR § 95891(c).

[39] Staff Proposal at 45.

An emission factor that is too high may result in windfall revenue allocations to facilities that purchase the majority of their electricity from IOUs; conversely, if the factor is too low it could result in shortfalls in revenue allocations to facilities that purchase electricity from over-the-fence CHP generators.

Staff also considered two alternative statewide emission factors: 0.378 $MTCO_2e/MWh$, based on total average statewide electricity emissions divided by total statewide electricity sales from 2008 through 2010;[40] and 0.34 $MTCO_2e/MWh$, based on a public GHG Calculator developed for the Commission by E3.[41] The Joint Parties supported the use of 0.378 $MTCO_2e/MWh$.

The Commission considered a comparable issue in a previous decision. In D.11-09-015, the Commission approved modifications to the Self-Generation Incentive Program (SGIP) in response to Senate Bill 412 (2009), which required that SGIP eligibility be based on GHG emissions reductions. To be eligible for SGIP, the Commission decided that a product or technology must produce fewer GHG emissions than it avoids from the grid.[42] D.11-09-015 decided that an emissions factor of 349 kg CO_2e/MWh (0.349 $MTCO_2e/MWh$) was a reasonable proxy for calculating the GHG emissions of grid electricity at the time the

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[40] This analysis is based on ARB's MRR data on statewide emissions associated with electricity production. Electricity consumption data are published by the California Energy Commission at http://www.ecdms.energy.ca.gov/elecbyutil.aspx.

[41] See the GHG Calculator Version 3c, "Outputs" tab, updated October 7, 2010, and available at http://www.ethree.com/public_projects/cpuc2.php.

[42] D.11-09-015, at 11-12, Conclusion of Law 1.

decision was adopted.[43] It also supported the use of a 7.8% average transmission and distribution line loss factor when valuing the emissions of electricity purchases that on-site generation displaces. The resulting avoided emissions factor adopted in D.11-09-015 is 0.379 $MTCO_2e/MWh$.

D.11-09-015 explained that the 0.349 $MTCO_2e/MWh$ avoided emissions factor is based in part on the factor of 0.437 $MTCO_2e/MWh$ used in ARB's AB 32 Scoping Plan (2008) to estimate the benefits of avoided grid electricity based on the average emissions of natural gas electricity generation.[44] However, in D.11-09-015 we determined that it was reasonable to adjust this 0.437 $MTCO_2e/MWh$ factor downward by 20% to reflect the fact that the utilities' electricity resource mix includes renewable resources required under the RPS statute. The Commission explained that ARB's emissions factor of 0.437 $MTCO_2e/MWh$ was "based on the [weighted average] emission rate of gas-fired power plants from 2002 to 2004, and it does not reflect the lower emission rate of newer gas-fired units that SGIP projects may avoid going forward,"[45] the implication being that this factor is conservatively high. Additionally, the Commission explained that the 20% RPS discount was reasonable to use, and likely conservative, because the RPS program target was revised to 33% by 2020, which is likely to further reduce the emissions of avoided grid purchases.

To address the concerns associated with the use of a statewide emissions factor, the Staff Proposal recommended adoption of utility-specific emission

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[43] *Id* at 15.

[44] ARB Climate Change Scoping Plan Appendices, Volume II: Analysis and Documentation, Appendix G: Economic Analysis, 2008.

[45] D.11-09-015 at 15.

factors based on public data that approximates the emissions embedded in each utility's resource portfolio. Under this proposal, each CCA and DA would be assigned the same emission factor as the interconnecting or host utility. Off-site CHP would be assigned the same emission factor – 0.431 $MTCO_2e/MWh$ – that ARB assigns to electricity exported by on-site electricity generators.[46] Staff notes that, ideally, emissions factors should be specific to each IOU and each third party electricity provider (including POUs, electricity marketers, and over-the-fence CHP). This approach would allow the emission factors to reflect the emissions intensity of each utility more accurately than a single statewide emission factor and is consistent with ARB's intent to account for actual emissions as accurately as practicable. This approach would also minimize the potential for windfalls.

The Staff Proposal presents three potential methods of calculating IOU emissions factors.[47] In Tables 1 and 2, Options A and B treat ARB's allowance allocations to each utility as proxies for each utility's total portfolio emissions from electricity procurement.[48] ARB allocated allowances to each utility based on projected emissions that will result from generation resources in a utility's portfolio, including fossil-fueled and non-emitting resources as well as cumulative investments in energy efficiency and early action investments in

[46] Staff Proposal at 47 - 55.

[47] Staff Proposal at 47-55.

[48] ARB allocated allowances to IOUs and POUs based on its analysis of 2009 Form S-2 that all utilities provide annually to the California Energy Commission.

qualifying renewable energy.[49] Option A includes credits for energy efficiency and renewable investments, while Option B excludes credits for energy efficiency and renewable investments. Option C reflects 2008 baseline utility and region-specific emissions factors published in Version 3 of the Commission's GHG Calculator developed by E3, updated in 2010.[50]

For electricity sold by DA/CCA/ESP providers, staff recommends that the Commission apply the emission factor adopted for the interconnecting or host IOU.

The Joint Utilities supported staff's recommendation to use the emission factors included in Table 2, Option A, of the Staff Proposal.[51] The Large Users and Gerdau argue that the Commission should choose an emission factor for DA providers that reflects the avoided emissions implicit in the wholesale market price because electricity marketers do not have the benefit of zero emissions resources such as hydro or nuclear generators.[52] The Large Users also argue that the Commission should treat the customers of investor-owned utilities and DA providers in a competitively neutral manner. Tesoro notes that under the utility-specific approach, an EITE customer would receive different revenue allocations for purchases from the same ESP depending on where the ESP delivered the

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[49] For background on ARB's methodology on allocating allowances to electric sector ratepayers, *see* Appendix A to ARB's July 25, 2011, Public Notice, "Staff Proposal for Allocating Allowances to the Electric Sector."

[50] For background on the Commission's GHG Calculator, see "GHG Calculator version 3c" available at:http//ethree.com/public_projects/cpuc2.php.

[51] The Staff Proposal recommends the following factors: 0.291 $MTCO_2e/MWh$ for PG&E; 0.387 $MTCO_2e/MWh$ for SCE; and 0.331 $MTCO_2e/MWh$ for SDG&E.

[52] Large Users Comments at 15.

power.[53] Tesoro supports a single statewide factor for ESPs no lower than 0.387 $MTCO_2e/MWh$.

We do not have record information regarding the contracts between DAs/CCAs and their customers. Therefore, it is unclear how the Commission could estimate DA/CCA providers' emission factors based on public data. DA/CCA electricity rates could be could be fixed, tied to IOU rates, or linked to the wholesale market. Absent specific DA/CCA information, it is not possible to determine whether a DA/CCA customer is paying GHG costs even if wholesale rates include a GHG price signal. Accordingly, adopting higher emissions factors than those evidenced by IOU data would disadvantage the IOUs and potentially reward providers with higher emission factors.

We also note that the Large Users raised concern that a single statewide emission factor could have the perverse effect of rewarding inefficient facilities that happen to be located in a relatively clean utility territory, and, conversely, penalizing efficient facilities that happen to be located in a relatively emissive utility territory. As we discuss below, our choice of emission factors and our decision to develop product benchmarks that represent the electricity intensity of product output will mitigate these concerns.

For the purpose of allocating allowance revenue to EITEs under the product, energy and refinery allocation methodologies, it is reasonable to adopt the emission factor of 0.379 $MTCO_2e/MWh$ established in D.11-09-015 for electricity purchases from all IOUs, POUs, and ESPs, with the exception of PG&E.

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[53] Tesoro comments on Staff Proposal, at p. 5.

The statewide factor of 0.379 $MTCO_2e$/MWh appropriately reflects that the costs of carbon in wholesale electricity prices in California is typically based on a marginal natural gas generator, and it also appropriately reflects that all load serving entities in California are obligated to meet minimum RPS requirements to procure zero-emitting renewable electricity, which for the IOUs has the effect of both reducing portfolio emissions intensity and carbon costs per MWh of electricity delivered to bundled customers. PG&E, however, has access to additional zero-emission large hydro and nuclear resources that are unavailable to other utilities and ESPs; thus, its emission intensity is not accurately represented by marginal gas generators and minimum RPS obligations, and it is more nearly represented by the lower portfolio emission factor of 0.291 $MTCO_2e$/MWh cited in the Staff Proposal. Therefore, for EITE electricity purchases from PG&E it is reasonable to use a utility-specific emission factor of 0.291 $MTCO_2e$/MWh.

Though we adopt an emission factor of 0.291 $MTCO_2e$/MWh for electricity purchases from PG&E, it is reasonable to use the statewide emission factor of 0.379 $MTCO_2e$/MWh for electricity purchases from ESPs that serve unbundled PG&E customers, since these ESPs also do not have access to the hydro and nuclear resources in PG&E's portfolio.

4.5.1. Off-Site CHP

The Staff Proposal recommended that the Commission adopt the same 0.431 $MTCO_2e$/MWh factor that ARB applies for electricity sold by on-site generators (*i.e.* CHP), noting that ARB's use of an emissions factor of 0.431 $MTCO_2e$/MWh for electricity exports in its direct allocation acts as a constraint that the Commission must consider to avoid potential inequities between on-site and [off-site] CHP that could arise if the Commission's allocation uses a

substantially different emission factor. While it is technically possible to develop emission factors for each CHP facility, this effort would require significant time and analysis to determine what portion of a CHP's facility's total emissions should be allocated between electricity production and useful steam production. CCC, Tesoro, and the Large Users agreed that it is appropriate to apply a 0.431 $MTCO_2e/MWh$ emission factor to electricity that EITEs purchase from off-site CHP facilities. No parties objected to the use of this factor for electricity purchases from off-site CHP facilities. This approach also maintains consistency between the off-site CHP factor and ARB's fixed 0.431$MTCO_2e/MWh$ factor for electricity exports. We find it reasonable to apply a factor of 0.431 $MTCO_2e/MWh$ to electricity that EITEs purchase from off-site CHP.

4.6. Source of Electricity Purchases

Industrial facilities can sprawl over large geographic areas and contain many electricity meters. Facilities may span multiple IOU territories; they may cross IOU and POU territories; and they may include purchases from utilities and non-utility third parties, including off-site CHP. By evaluating all sources of electricity purchases, benchmarks will result in an accurate snapshot of an industrial sector's historical baseline emissions intensity or an individual facility's historical baseline electricity emissions.

It is reasonable to consider all potential sources of electricity purchases when developing benchmarks, with the exception of POU electricity in the energy-based benchmark, as explained below; therefore, the benchmark formulas must account for all sources of electricity purchases. Staff suggested that the

Commission use ARB's Mandatory Reporting Regulation (MRR)[54] data when calculating product benchmarks, as well as when conducting energy and refinery allocation calculations. No party objects to this recommendation, and all parties supported the general use of MRR data, with certain exceptions that we note in subsequent sections.

4.7. Product-Based Allocation Formula

All sectors that receive Industry Assistance from ARB according to a product output-based allocation methodology should also receive GHG allowance revenue through a product-based allocation methodology. The industrial sectors that should receive a product-based allocation of revenue from the Commission are those represented by NAICS Code in Table 9-1 of ARB's Cap-and-Trade regulation, as may be modified over time. As noted in the Staff Proposal, some modifications to ARB's product-based allocation formulas are necessary to make them applicable to indirect emission costs from electricity purchases. The Commission's methodologies include a dollar conversion factor, emissions factors for various electricity providers, and true-up terms to account for timing disparities between when product output data are available each year and the month when the Commission allocates revenue to eligible facilities. Additionally, though the product-based benchmark formula reflects all sources of electricity purchases, as described below, the Commission should only allocate allowance revenue for the fraction of a facility's annual product output that is associated with IOU, ESP or CHP electricity purchases. The Commission cannot

[54] Reporting of GHG by major sources is required by the California Global Warming Solutions Act (AB 32). The MRR is the mechanism by which major sources must report necessary information to ARB in order to calculate a facility's GHG emissions.

expect that electricity purchased from POUs includes a carbon cost; therefore, the facility's product output included in the product-based formula should be discounted by the fraction of electricity purchased from POUs relative to the facility's total electricity purchases. This discounting should be based on the most current MRR data available, and to minimize administrative complexity it should not be trued up over time. The adopted product-based allocation formulas are set forth in Appendix A.

4.7.1. Product Benchmark Formula

"[Product-based emissions intensity benchmarks] are metrics that enable the comparison of GHG emissions performance across similar industrial facilities."[55] The product benchmarks developed by ARB are a key part of ARB's product-based allocation methodology. ARB's product-based benchmarks are a measure of sector-wide emissions intensity: metric tons of carbon dioxide equivalent gas per unit of industrial output for each industry. The product benchmark allows each facility's allocation of allowances to vary with the facility's annual product output, and it ensures that GHG efficient facilities are at an advantage relative to their peers.

ARB's benchmark methodology takes into consideration all direct emissions and emissions associated with steam purchases, less any emissions associated with steam sales and electricity exports. As a complement to ARB's benchmark, the Commission's benchmark variable, B_{EP}, must take into account electricity purchases, the sole energy source omitted from ARB's benchmarks.

[55] ARB ISOR Appendix J at 21.

Staff notes that the Commission has a choice to develop a product benchmark that represents either electricity intensity or the electricity emissions intensity of product output. An electricity intensity benchmark would reflect an industrial sector's average electricity purchases per unit of product output (megawatt-hours/output). Such a benchmark would capture the relative efficiency of each facility's operations, but it would exclude the emissions intensity of a facility's electricity sources - that is, the emissions intensity of their electric provider(s). Alternatively, an electricity emissions intensity benchmark would capture an industrial sector's electricity intensity as well as the emissions intensity of its electricity providers (the benchmark would be in units of $MTCO_2e$/output).

Staff recommends that the Commission adopt a benchmark that reflects electricity intensity. Staff explained that if the Commission adopted utility-specific emissions factors and then calculated an emissions intensity benchmark – which averages emissions over an entire industry – this calculation would have the effect of averaging each utility's emissions factor, negating the benefit of using utility-specific emissions factors.

The Joint Parties support the use of an electricity intensity benchmark. The Large Users also support this approach, so long as the Commission does not approve emissions factors that update annually. CCC opposes the use of an electricity intensity benchmark on the grounds that it introduces unwarranted complexity and creates potential inequities between on-site versus off-cite CHP.

We find that an electricity intensity benchmark best reflects ARB's product benchmarking methodology. To convert this benchmark into emissions, each EITE facility that receives a product-based allocation will have its own facility-specific emission factor, which reflects the weighted average emissions

from electricity that the EITE facility purchases from IOUs, ESPs or CHP facilities, using the electricity provider-specific emission factors discussed above. In light of the fact that an EITE facility may have a different balance of electricity purchases between IOUs, ESPs or CHP facilities each year, it is reasonable to update the EITE facility-specific electricity emission factors used in each year's product-based allocation to reflect the most recent MRR data available, even though both the electricity intensity benchmark and the electricity provider emission factors should remain fixed.

4.7.1.1. Impacts on Self-Generators

Facilities that rely on on-site CHP or other self-generation generally tend to be more directly emissive than comparable facilities that purchase electricity from third parties. Since ARB's direct allocations of allowances do not evaluate emissions from electricity purchases, and ARB's product benchmarks are sector-wide averages, ARB's direct emissions benchmark results in a relative under-allocation to entities that have on-site CHP and an over-allocation to entities that purchase their electricity from third parties. For example, in an industry with two facilities that are equal in every regard, except that one has on-site CHP and the other purchases electricity from off-site CHP, the facility that purchases electricity from off-site CHP will generally have fewer direct emissions. When ARB averages the direct emissions of these two facilities, the resulting product benchmark (direct emissions per product output) would treat the facility with on-site CHP as if it only had half of the direct emissions associated with electricity production as it actually does. The benchmark will reward the facility that purchases electricity from off-site CHP for on-site electricity production that it does not have. Several parties have recommended that the Commission correct this outcome.

The Commission's product output benchmarks (electricity purchases per unit of product output) will correct this outcome –facilities that have on-site CHP will tend to lower the benchmark of electricity purchases because they self-generate electricity, which does not count as an "electricity purchase" in the benchmark, and facilities that purchase the majority of their electricity will tend to raise the benchmark. In the end, ARB's direct emissions benchmark and the Commission's electricity purchases benchmark should balance out to ensure that facilities are not unjustly penalized for opting to procure electricity from on-site CHP or from a third-party. Even if an EITE facility has no annual electricity purchases, it will still receive an annual allocation of revenue under the product-based allocation if it operates in an industry eligible for a product-based allocation.

4.7.2. Stringency Factor

ARB's benchmark formulas include a stringency factor. The intent of the stringency factor is to create a benchmark that reflects the emissions intensity of highly efficient, low-emitting facilities within each sector. In developing its product-based benchmarking methodology, ARB evaluated "each industrial sector's production weighted average emissions intensity during a historical base period [and then targeted] the benchmark to allocate 90% of this level per unit product."[56] This ensures that facilities still experience some downward pressure to reduce their GHG emissions, even though they may receive allowances for a substantial portion of their direct emissions. ARB applies this 90% stringency

[56] ARB July 25, 2011, Notice of Public Availability of Modified Text, Appendix B: Development of Product Benchmarks for Allowance Allocation, at 3. Available at: http://www.arb.ca.gov/regact/2010/capandtrade10/candtappb.pdf

factor as a default. However, upon reviewing the results of its benchmark values, ARB staff found that for some sectors the stringency approach resulted in a benchmark level that was more stringent than the current emissions intensity of any existing Californian facility in the sector. For the sectors in which this occurred, ARB applied a benchmark to that sector that was based on the "best-in-class" value for that sector (*i.e.* the emissions intensity of the most GHG-efficient California facility).[57]

The exclusion of a stringency factor from the indirect allocation could negatively impact facilities that choose to generate their own electricity on-site via CHP plants. Since the stringency approach applies to direct emissions, it should also apply to indirect emissions from electricity purchases to avoid advantaging those facilities that procure their electricity rather than generate it onsite.

We adopt the approach approved by the ARB. The stringency factor should be applied to all industries that receive a product-based allocation, except where ARB has determined that the "best-in-class" approach should be used.

Energy Division staff should coordinate with ARB to obtain the information necessary to determine which industries should receive revenue allocations based on the best-in-class approach.

4.7.3. Subsector Benchmark

The development of benchmarks poses a particular challenge for industries that have subsector activities. Benchmarking is relatively straightforward in cases when a single facility operates in an industry that has

[57] *Id*. at 3.

only one benchmark. Cement manufacturing is one such industry. When a facility operates in only one industrial activity it is a trivial matter to input ARB's MRR data about a facility's total electricity purchases directly into the product-based benchmark formula. However, benchmarking is more complicated when a single facility produces more than one type of related product, each of which has its own product-based benchmark in ARB's Cap-and-Trade Regulation.

For example, the Rolled Steel Shape Manufacturing Sector (NAICS Code 331221) has five different subsector activities and associated benchmarks – hot rolled steel, pickled steel, cold rolled steel, galvanized steel and tin steel plate production. Two California companies operate in this sector: USS-POSCO and California Steel Industries (CSI). Both companies produce multiple types of products included within the Rolled Steel Shape Manufacturing Sector. In this case, ARB's MRR data about a single facility's total electricity purchases provides no clear insight into what percentage of USS-POSCO's or CSI's electricity purchases are associated with one subsector activity versus another.

To calculate benchmarks of electricity purchases for these subsectors and others, the Commission either needs supplemental data from the affected industries, or it needs a method to estimate electricity purchases by subsector based on other available data.

The Staff Proposal identified three options to address the issue of subsector benchmarks: 1) use MRR data about relative natural gas usage by subsector activity as a proxy for electricity purchases by subsector, 2) rely on voluntary reporting of auditable data of electricity use by subsector activity, or 3) use MRR data about relative product output as a basis for splitting electricity purchases by subsector.

In comments, USS-POSCO argues that there is no reason to expect any correlation between subsector natural gas use and electricity use by subsector production. If natural gas is used as a proxy, USS-POSCO argues that the resulting allocation of revenue should be verified to ensure consistency with actual electricity consumption.

Each of the three options for addressing subsector benchmarks may be appropriate in differing circumstances. In the proposed decision, we recommended an interim solution that mirrors ARB's method of resolving this issue: when a single industrial facility operates in multiple EITE-eligible industrial activities, we will estimate electricity purchases by industrial subsector activity by relying on the same percentage allocation factors that ARB used to apportion total natural gas use by industrial subsector activity. This approach is consistent with ARB's allocation methodology, and it will minimize administrative complexity and staff workload, since the necessary data are already available.

Alternatively, we suggested that covered entities in a sector with subsector activities may use one of the following two alternative approaches: apportion electricity usage by subsector activity according to audited electricity usage by subsector, accompanied by an attestation and independent engineering audit verifying the electricity usage data; or apportion electricity purchases by subsector according to the relative subsector product output if all covered entities agreed and stated their preference to the Director of the Energy Division no later than 90 days after the effective date of this decision. The historical electricity usage by subsector would be calculated once and not updated.

In comments to the proposed decision, USS-POSCO suggests that if audited subsector electricity data is available for all California covered entities

with subsector activities, and the entities provide the audited data, accompanied by an attestation and independent engineering audit verifying the electricity usage data, that data could be used to determine the allocation factors for that subsector. For subsectors for which auditable electricity usage is not available, electricity purchases by subsector will be allocated according to the relative subsector product output, excluding usage in subsectors for which audited data has been provided.[58]

In its comments, CLECA, as a representative of CSI, offers a similar approach, suggesting that the Commission adopt the natural gas-based allocation factor for the "Hot Rolled" subsector (a subsector of which CSI is the only member), and use audited production data to establish the allocation factor for "tin steel" subsector (a subsector of which USS-POSCO is the only member).[59] USS-POSCO supports this approach. Under this approach the remaining overlapping subsectors would then receive a common allocation based on electricity use and production data reported to ARB through its MRR. [60] We find this alternative approach reasonable.

4.8. Energy-Based Allocation Formula

All sectors that receive Industry Assistance from ARB according to an energy-based allocation methodology should also receive *GHG allowance revenue* through an energy-based allocation methodology.

ARB's energy-based allocation is based on a fixed historical baseline amount of direct emissions by facility. To apply ARB's energy-based allocation

[58] December 8, 2014 Comments of USS-POSCO, at pp. 4-5.

[59] December 15, 2014, Reply Comments of USS-POSCO at p. 1.

[60] *Id*, at p. 2

methodology to emissions from electricity purchases, we must make two modifications to ARB's formulas: it must revise the emissions benchmark variable, B, to reflect emissions from electricity purchases, and it must introduce a dollar conversion factor, D, to convert allowances into dollars. The adopted energy-based allocation formulas are set forth in Appendix A.[61] For the emission factors, assistance factors, the cap adjustment factor and the dollar conversion factors that are variables in these formulas, we adopt the definitions discussed above. The energy-based allocation will be returned on a prospective basis as with all other EITE allocations, and it will be trued up over time to account for the current year's dollar conversion factor once it is known.

ARB's April 25, 2014, amendments to its Cap-and-trade Regulation include a new provision that addresses how the energy-based allocation methodology should apply to covered entities in industrial sectors that were not included in Table 8-1 prior to 2014.[62] If an entity meets three criteria: 1) it had emissions above the Cap-and-Trade inclusion threshold prior to 2012; 2) it was not listed in Table 8-1 prior to 2014 (i.e., it was not eligible for Industry Assistance); and 3) it is currently eligible to receive an allowance allocation under the energy-based allocation methodology, the entity will receive a true-up allocation in 2015 to account for the allowances it did not receive for 2013 and 2014. This true-up will be in addition to the allowances it will otherwise receive for 2015, according to

[61] ARB's April 25, 2014 amendments to its Cap-and-Trade Regulation included a change in the format, but not the content, of how it defines true-ups for the product-based allocation. These formatting changes improve clarity and do not alter how true-ups would be conducted for the product-based allocation. The true-up terms in Appendix A reflect this formatting change throughout the product, energy, and refinery allocation methodologies, and thus may appear different than the true-ups included in the Staff Proposal, though in effect they are identical.

[62] Cap-and-Trade Regulation Section 95853(e).

the energy-based allocation methodology. This new provision is not directly relevant to individual EITE entities, so there is no need to grant this class of entities a true-up. Since these entities are currently captured in Table 8-1, as revised in April 2014, they will receive allowance revenue for 2013 and 2014 in the same manner as other eligible entities that have been included in Table 8-1 since 2012.

No party provided comments on the specific energy-based allocation formulas set forth in the Staff Proposal. The adopted energy-based formula is set forth in Appendix A to this decision.

All aspects of the energy-based allocation formula, including proposed modifications, are discussed below.

4.8.1. Benchmark of Historical Electricity Emissions

ARB's energy-based benchmark methodology takes into consideration all direct emissions and emissions associated with steam purchases, less any emissions associated with steam sales and electricity exports. As a complement to ARB's benchmark, the Commission's benchmark variable must take into account electricity purchases, the sole energy source omitted from ARB's benchmarks.

The historical electricity emissions benchmark is specific to each facility that qualifies for an energy-based allocation. The formula for an industrial facility's historical baseline electricity emissions benchmark is distinct from the emissions benchmark used in a product-based allocation methodology. While the benchmark variable used in the product-based allocation reflects electricity intensity of industrial output and is an average across all facilities in an industrial sector, the benchmark used in the energy-based allocation reflects historical average emissions from electricity purchases specific to each facility.

Because the benchmark used in the energy-based allocation methodology is EITE facility-specific and is a metric of a facility's historic electricity purchases, rather than the industry-average emissions per unit of product, the Commission should exclude any electricity purchased from POUs from this benchmark calculation. ARB allocated allowances to POUs in the same manner as it did for IOUs. However, the Commission has no insight into how the boards of POUs have decided to use their directly allocated allowances from ARB, and the Commission cannot assume that electricity purchased from POUs includes a carbon price signal. Thus, it would be inappropriate for the Commission to compensate EITE facilities for GHG costs that may be present in POU electricity rates; POUs are responsible for their customers that are EITEs.

The Commission's benchmark variable uses ARB's MRR as the data source for electricity purchases, and a utility-specific emissions factor as discussed above. The historical period for each industrial sector should match the historical period that ARB used when it allocated allowances to address direct emissions.

The adopted definitions of emissions factors, assistance factors, the cap adjustment factor and the dollar conversion factor used in the energy-based allocation methodology should be consistent with those of the product-based allocation methodology and refinery methodology discussed herein.

The adopted benchmark formula, is found is Appendix A to this decision.

4.8.1.1 Updates to Benchmark

ARB calculated historic direct emissions benchmarks once at the outset of the Cap-and-Trade program and does not plan to update these benchmarks. Our decision mirrors that of ARB: the adopted benchmarks should be calculated only once and used for the duration of the Cap-and-Trade program. However, should

ARB substantively revise the benchmarking methodologies defined in its Cap-and-Trade regulation, it may be appropriate to make corresponding modifications to the benchmarks and formulas adopted herein. In the event ARB adopts substantive revisions to its benchmarking methodologies, Energy Division should issue a resolution containing recommendations for updated benchmarks, benchmarking methodologies or formulas for consideration by the full Commission.

4.9. Refinery Formulas

For the first Cap-and-Trade compliance period, ARB employs a two-tiered approach to allocating allowances to the refinery sector. First, ARB allocates allowances to the refinery sector as a whole based on a product-based, "simple barrel," benchmark. This allows the total amount of allowances allocated to the refinery sector to increase or decrease automatically in response to future production levels of refinery products. Second, ARB allocates allowances to individual refineries based on the complexity of the refinery. For simple refineries (*i.e.* those without a Solomon Energy Intensity Index (EII) value), ARB allocates allowances based on a simple barrel product benchmark methodology, and for complex refineries (*i.e.* those that have an EII value), ARB allocates allowances based on a more complex formula that accounts for each refinery's historical emissions and its relative efficiency compared to other refineries ARB distinguishes between simple and complex refineries because complex refineries conduct a variety of emissions-intensive processes and produce a variety of products that would be disadvantaged under the simple barrel metric.

Under the simple-barrel methodology, ARB allocates allowances to individual refineries in a manner that exactly mirrors ARB's product-based methodology; however, ARB limits the amount of allowances each simple

refinery can receive to no more than the refinery's average historical emissions adjusted by the refinery assistance factor and the cap adjustment factor.

After allocating allowances to simple refineries, ARB divides the rest of the refinery sector allocation among complex refineries that have a Solomon EII value based on the historical emissions of each refinery, an adjustment factor based on the emissions intensity of all complex refineries, and the current emissions for each refinery. The Solomon EII is a complexity-adjusted measurement of energy efficiency developed by Solomon Associates, which maintains an extensive database on global refineries' operations. The Solomon EII is the industry standard for comparing energy efficiency across refineries globally, and California refineries that have a Solomon EII value represent over 90% of the refining capacity in the state. Under ARB's approach, the refinery with the most efficient operations (*i.e.* the lowest EII value) will receive the greatest portion of allowances.

Staff proposes two primary changes to ARB's refinery allocation methodology for the purpose of providing revenue to address costs from electricity purchases. The first change affects ARB's benchmark variable, which is modified to account for emissions from electricity purchases, as opposed to direct emissions; and the second change is the introduction of a dollar conversion factor, D, identical to the dollar conversion factor used in the product-based and energy-based formulas to convert allowances into dollars.

No party objects to the proposed refinery allocation formulas, including appropriate modifications, and Tesoro specifically supports the proposed methodology.

One additional change to ARB's refinery methodology is necessary, as explained above for the product-based allocation methodology: the refinery

benchmarks should reflect all sources of electricity purchases and all product output; however, the refinery sector allocation and the refinery-specific allocations should only reflect the portion of product output that is associated with electricity purchased from IOUs, ESPs and CHP – it should exclude product output associated with the fraction of electricity that refineries purchase from POUs. This modification is necessary to ensure that the Commission is not compensating EITE facilities for carbon costs that may not be present in POU electricity rates; POUs are responsible for their customers that are EITEs.

Though ARB's refinery allocation formulas are complex, the benefits of pursuing a comparable methodology to address indirect emissions costs embedded in electricity rates outweigh any administrative complexity. Any major methodological divergence between ARB's direct allocation and the Commissions allocation to address indirect costs could potentially result in inequities between on-site and off-site CHP.

The adopted refinery sector allocation formulas are set forth in Appendix A to this decision. As with the product-based and energy-based formulas, GHG revenue will be returned on a prospective basis with the appropriate true-up variable in place.

In the Cap-and-Trade Regulation amendments approved on April 25, 2014, ARB introduced a new true-up term into the allocation methodology for simple refineries (*i.e.* those without an EII value). The purpose of this term, as with true-ups in the product-based allocation, is to correct the 2013 and 2014 allocations to reflect actual 2013 and 2014 product output once that data is available. The refinery allocation methodology included in Appendix A reflects ARB's new true-up equations since these equations only require the same minor

modifications that have been discussed throughout this decision and vetted by parties in comments and workshops.

4.9.1. Refinery Allocation under the Second and Third Cap-and-Trade Compliance Periods

The refinery allocation formulas adopted above are applicable only to the first compliance period of the Cap-and-Trade program (2013 and 2014). ARB's April 2014 amended Cap-and-Trade Regulation relies on a CWB allocation methodology in the second and third compliance periods (2015 through 2020). This approach would allow ARB to allocate allowances to refineries in a manner that accounts for GHG intensity, complexity and annual output of each refinery; it would vastly simplify the allocation methodology; and it would not be dependent on a proprietary index, which would increase the transparency of the allocation methodology.

We have not considered how the new CWB approach fits within the Commission's EITE revenue allocation methodologies and whether any modifications are necessary to address indirect emissions from electricity purchases; therefore we direct staff to conduct a workshop and prepare a workshop report providing recommendations an updated refinery allocation formulas that reflect the CWB approach adopted by ARB.

5. New Market Entrants and Facility Closures

5.1. New Market Entrants

We committed in D.12-12-033 to provide allowance revenue to any entity in an industry eligible for Industry Assistance, regardless of annual level of

emissions.[63] This includes both existing businesses and new businesses that may begin operating in California in the future. ARB's April 2014 amendments to the Cap-and-Trade Regulation significantly change how ARB treats new entrants. ARB added a class of new entrants without leakage risk,[64] and it clarified how the energy-based allocation methodology should be used for new entrants in the case of: A) opt-in covered entities without historical baseline emissions; B) entities with transitional emissions data; and C) entities with stable emissions data. [65] The effect of these changes is to introduce new industry assistance eligibility conditions and to provide more flexibility to entities that have widely varying annual emissions. Since we have committed to flowing through any changes in ARB regulations in our implementation of the program, no further review is needed to introduce ARB's new eligibility criteria into the Commission's EITE revenue allocation methodologies; it is only necessary to apply consistent changes to ARB's new entrant regulations that have been discussed throughout this decision (*e.g.* to introduce an electricity emission factor and a dollar conversion factor). These rules for new entrants should also apply to EITE entities addressed in Section 6.2 that have annual direct emissions below 10,000 MTCO2e.

The sections below discuss each of ARB's Cap-and-Trade amendments affecting new entrants that the Commission mirrors in Appendix A.

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[63] D.12-12-033 COL 13.

[64] Cap-and Trade Regulation Section 95891(c)(3).

[65] *Id* at Section 95891(a)(3).

5.1.1. New Entrant Industrial Allocation without Leakage Risk

Some entities that are now covered facilities under Cap-and-Trade had emissions that fell below ARB's inclusion threshold prior to 2012, and are also not among the industries explicitly listed by NAICS Code in Table 8-1. However, ARB determined that if the first three digits of such an entity's NAICS Code match the first three digits of a NAICS Code in Table 8-1 of ARB's Cap-and-Trade Regulation, these covered entities should be classified as having a low leakage risk, and they should be eligible for an energy-based allocation.[66] ARB exempts food processors from this classification. These new amendments only affect ARB's definition of eligibility for Industry Assistance for covered entities. D.12-12-033 concluded that ARB's modifications to the eligibility criteria for Industry Assistance should extend to the Commission's revenue allocation for EITE entities;[67] therefore, the Commission's allowance revenue allocation should mirror these new eligibility criteria.

5.1.2. Opt-In Covered Entities without Historical Baseline Emissions Data

For opt-in covered entities eligible for the energy-based allocation that have not reported any historical emissions data to ARB under MRR, ARB will use estimates of fuel use and electricity sales in its energy-based allocation formulas.[68] In normal circumstances, ARB uses historical baseline MRR data rather than estimates. We can return allowance revenue to these facilities if ARB develops estimates of such facilities' electricity purchases. If ARB does not have

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[66] *Id.* at § 95891(a)(3).

[67] D.12-12-033 COL 13.

[68] Cap-and-Trade Regulation § 95891(c)(3)(A).

estimates of electricity purchases, it will not be administratively feasible for the Commission to produce these estimates, and it will not be possible to return allowance revenue to these facilities until ARB has verified MRR data for these facilities. If ARB produces estimates of electricity purchases, the energy-based methodology in Appendix A will apply, except that it will rely on ARB's estimates of a facility's electricity purchases, rather than a historical baseline. Once ARB has MRR data for such facilities, they will receive allowances according to § 95891(c)(3)(B) or (C) of the Cap-and-Trade Regulation, discussed below, and the Commission will revert to using ARB's MRR data about electricity purchases, rather than estimates.

5.1.3. Entities with Transitional Emissions Data

ARB's amended regulations include a new stability formula for the energy-based allocation that classifies entities as having either transitional or stable emissions. A facility with transitional emissions has emissions that are more than 10% higher than the average of its emissions from the prior two years. Facilities with stable emissions are those for which this difference is less than 10%.

For facilities that have transitional emissions, ARB does not use historical baseline levels of fuel use, steam purchases and electricity sales. Instead, when allocating allowances for budget year "t," ARB uses emissions data for year "t-2," the most recent year for which verified MRR data are available.[69] This approach is mirrored in Appendix A: when ARB classifies a facility's emissions as transitional and the facility is eligible for an energy-based allocation, we will

[69] For example, when ARB allocates allowances for 2015 emissions, it relies on the most recent MRR data, which would be 2013 data.

use MRR data for year "t-2" electricity purchases, where "t" is the Cap-and-Trade budget year for which the facility is receiving allowance revenue.

As noted throughout discussions in this decision about the product-based allocations, years 2013 and 2014 are special cases: when the Commission implements the calculations for emissions associated with years 2013 and 2014, it is likely that verified 2013 MRR data will be available.[70] Thus, for the Commission's 2013 and 2014 allocations to entities with transitional emissions data, it is appropriate to use the most recent MRR data available. This data may not strictly match the year "t-2" in ARB's regulations. For 2015 and all subsequent years, year "t-2" data should be used.

5.1.4. Entities with Stable Emissions Data

Once ARB classifies entities as stable in the stability formula, the facility will receive an energy-based allocation, and this methodology will apply in all subsequent years.

5.2. Facility Closures

We must also decide how to treat facilities that cease operations altogether or that no longer engage in an EITE-eligible industrial activity. This issue is particularly relevant to the energy-based and refinery-based allocations, which depend on facility-specific benchmarks of historical electricity purchases that do not update over time. This issue is also relevant to the product-based allocation because annual product-output data is

[70] ARB collects verified MRR data by September of each year. It allocates allowances in October of each year. If the Commission allocates allowance revenue for 2013 after September 2014, it can make use of actual 2013 MRR data.

reported on a time-lag; product output data would not reflect a shut down until two years after the fact.

Only facilities engaged in EITE-eligible industrial activities as defined in D.12-12-033 are eligible to receive an allocation of GHG allowance revenue. Facilities should no longer receive revenue if they cease operations or if they are no longer primarily dedicated to EITE-eligible industrial activities. Before each annual allocation of GHG revenue, we will need to identify any facilities that receive energy-based or refinery allocations have ceased EITE-eligible industrial activities to ensure that these facilities do not receive an allocation of revenue unless and until they restart operations.

We direct Energy Division to work with ARB staff to obtain the facility information necessary to determine eligibility for an allocation of GHG revenue in advance of disbursement of revenue in a given year.

6. EITE Entities with Annual Emissions Less Than 25,000 MTCO2e (Small EITE Entities)

D.12-12-033 requires any facility that operates in a sector eligible for Industry Assistance and that has annual direct emissions less than 25,000 $MTCO_2e$ (small EITE entities) to voluntarily opt-into the Cap-and-Trade program in order to receive GHG allowance revenue for their indirect emissions. This requirement remains in effect until another method is developed to obtain the information necessary from the individual entity to accurately allocate GHG allowance revenue.[71]

[71] D.12-12-033 at FOF 58 COL 14. The GHG revenue allocation methodologies adopted for EITE entities require certain information that is reported to ARB through the MRR.

There are two classes of small EITE entities: those with emissions between 10,000 $MTCO_2e$ and 25,000 $MTCO_2e$ that do not have a compliance obligation under the Cap-and-Trade Regulation but are nevertheless required under ARB's MRR to report certain data to ARB; and facilities that have emissions below 10,000 $MTCO_2e$, which currently have no reporting or other requirements under the Cap-and-Trade or MRR. Currently, a facility with emissions under 25,000 $MTCO_2e$ may opt-into the Cap-and-Trade program if it desires a direct allocation of allowances (for its direct emissions), but the facility must submit certain information to ARB that must be verified by a third-party verifier.

6.1. Facilities with Annual Emissions Between 10,000 and 25,000 $MTCO_2e$.

D.12-12-033 stated that entities with annual emissions between 10,000 $MTCO_2e$ and 25,000 $MTCO_2e$ should continue to be required to opt-in to the Cap-and-Trade program in order to be eligible to receive GHG allowance revenue for their indirect emissions. Although these entities are already subject to ARB's MRR, and they report verified annual emissions and electricity purchases, they are not required to report annual product output data unless they choose to opt-in to the Cap-and-Trade program.

While product-output data is necessary for the Commission to return revenue according to the product-based methodology for EITE entities that have annual emissions between 10,000 $MTCO_2e$ and 25,000 $MTCO_2e$, it is possible to implement the energy-based allocation methodology using MRR data currently collected by ARB for entities between 10,000 and 25,000 $MTCO_2e$, without requiring these facilities to opt-in to Cap-and-Trade. The Food Processors argue that requiring facilities with direct emissions between 10,000 and 25,000 $MTCO_2e$ to opt in to Cap-and-Trade in order to be eligible to receive GHG allowance

revenue for their indirect emissions would constitute an unnecessary and unreasonable burden because it would impose new reporting and verification responsibilities. They maintain that for many small and medium companies, engaging a third-party verifier would represent a substantial investment of time and money that may actually exceed the amount of any forthcoming refunds.

We agree that to require facilities with annual emissions between 10,000 and 25,000 $MTCO_2e$ to opt-into the Cap-and-Trade program, as ordered in D.12-12-033, could be unduly burdensome. According to the Staff Proposal, the only information such facilities do not currently report to ARB is product-output data; all other information necessary to calculate a GHG revenue return through the energy-based methodology is already available through the MRR. To require all entities between 10,000 and 25,000 $MTCO_2e$ to opt-into the Cap-and-Trade program, regardless of whether they are in an industry that will receive GHG allowance revenue according to a product-based or energy-based formula, places an unnecessary administrative burden and expense on smaller facilities.

There would also be considerable staff burdens associated with collecting product-output data from facilities that do not already report this data to ARB, therefore, it is reasonable to use the energy-based methodology to return GHG allowance revenue to EITE entities that have direct emissions below 25,000 $MTCO_2e$ and that have not voluntarily opted into Cap-and Trade. However, if ARB revises its MRR to require entities with direct emissions between 10,000 and 25,000 $MTCO_2e$ to report verified annual product output data, we will apply the product-based allocation methodology to these facilities if they operate in industries eligible for the product-based methodology.

6.2. Facilities with Annual Emissions Less Than 10,000 MTCO2e

Facilities with annual emissions below 10,000 $MTCO_2e$ pose unique challenges. Facilities with such low-levels of direct emissions are effectively unknown to ARB – they are not covered by the Cap-and-Trade program and they are not covered by MRR. Therefore, it is difficult to identify such facilities or to verify the data necessary to calculate an energy-based allocation.

6.2.1. Identification and Verification of EITE Entities with Annual Emissions Below 10,000 $MTCO_2e$

Each of the utilities manually classifies its business customers by NAICS Code for reporting purposes. These classifications are not independently verified and are made based on the individual utility's judgment. To estimate the total number of EITE facilities that operate in utility service territories, staff requested information about the total number of unique facilities that operate in the NAICS codes listed in Table 8-1 of ARB's Cap-and-Trade Regulation. Staff also requested total 2012 bundled and unbundled electricity sales associated with these facilities. This data represents the total universe of potentially eligible EITE facilities within the large utilities' territories. Staff then subtracted the total number of facilities that report to ARB via MRR from the results of the data request. This difference represents the number EITE entities that have direct emissions below 10,000 $MTCO_2e$.

This preliminary analysis indicates that by expanding EITE eligibility to facilities that have direct emissions below 10,000 $MTCO_2e$, approximately 8,000 new entities would receive GHG allowance revenue according to an EITE distribution methodology. This represents a significant increase compared to the initial group of approximately 100 entities that are covered entities under the

Cap-and-Trade Regulation that were directly addressed in D.12-12-033. Therefore, the administrative burden to identify and administer the GHG allowance revenue return to these entities is not a trivial exercise.

To identify EITE entities with annual emissions less than 10,000 $MTCO_2e$, Staff suggests that the utilities develop an initial list of customer facilities that they have classified in EITE-eligible NAICS codes. Staff can then compare this list of customers against ARB's list of entities that report via MRR. Those customers that do not report via MRR would therefore be assumed to have direct emissions below 10,000 $MTCO_2e$.

Based on the initial list of customers that have been classified in EITE-eligible NAICS Codes, staff recommends that the utilities conduct outreach to each customer expected to operate in an industry that is EITE-eligible. To be eligible for an EITE allocation, these customers should then be required to sign an attestation that their facility is primarily engaged in activities described by an EITE-eligible NAICS Code. The Staff Proposal initially suggested that the utilities should be responsible for collecting and verifying these attestations, but by ruling dated October 16, 2013, the Staff Proposal was updated to recommend that a third-party disbursement agent be tasked with this responsibility. Given the administrative costs of conducting outreach to approximately 8,000 customers, staff recommended that verification of customer's eligibility should only occur once per Cap-and-Trade program period.

Staff recommends that customers, rather than utilities, bear ultimate responsibility for ensuring that a customer's facility is properly classified in an EITE-eligible NAICS Code. However, staff recommends that the utilities be responsible for developing a list of EITE-eligible customers and conducting outreach to these customers to educate them about their opportunity to attest to

their EITE eligibility. The Joint Utilities, in their October 30, 2014, comments, suggest that Commission staff or a third-party disbursement agent should be responsible for calculating all EITE revenue allocations, including those for EITE entities with annual direct emissions less than 10,000 $MTCO_2e$. In addition, the Joint Utilities maintain that any customer attestations must be made to the Commission and that a third-party disbursement agent should be responsible for collecting and managing customer attestations, ideally through a central website The Joint Utilities also state that revenue should be returned to EITE customers that have annual direct emissions less than 10,000 $MTCO_2e$ based on service account level information rather than facility-level account information for simplicity.

The Joint Utilities request clarification on the type and level of customer outreach that would be considered reasonable to ensure that customers are aware of the new NAICS code attestation process and they argue that the existing outreach budgets may be insufficient to cover such costs. Finally, the Joint Utilities believe that the attestation process should occur on a yearly basis, rather than once per Cap-and-Trade program period, since there may be new customers who come into the service territory that may be classified as EITE. If customers identify as EITE by the yearly deadline, the Joint Utilities propose that these customers would be added prospectively for the next year's allocation. CMTA requests clarification on how a disbursement agent would verify a facility's EITE status, and it states that a facility's primary business activity can vary from year to year based on orders from customers, contracts, and corporate decisions to relocate various aspects of the production process. CMTA is therefore concerned that the attestation process would be lengthy and yield

arbitrary results. To that end, CMTA requests that a dispute resolution process be put in place if an entity believes it has wrongly been denied EITE status.

As noted above, at this time the Commission does not have budget authority to contract with and utilize a disbursement agent to collect, manage or distribute GHG allocation revenue. Accordingly, the identification, verification and revenue allocation calculation for EITE entities with annual emissions less than 10,000 $MTCO_2e$ must be performed by either the Commission staff or the IOUs.

The IOUs maintain that the Commission staff should be responsible for collecting the attestations and the relevant service agreement data from the small EITEs that wish to receive allowance revenue. They also maintain that the attestations should be to the Commission, not to the IOUs, and that the attestation process should be conducted through a centralized collection website.

We agree that customer attestations should be made to the Commission, not the IOUs. However, each IOU is best situated to identify potential EITE customers with annual emissions less than 10,000 $MTCO_2e$. Therefore, we require the utilities to contact customers that are likely to be eligible EITEs and collect attestations from customers that choose to demonstrate eligibility to receive allowance revenue. We adopt the following high level parameters for identification and verification of EITE entities with annual emissions less than 10,000 $MTCO_2e$ to ensure that GHG allowance revenue is returned to these entities accurately and as efficiently as possible.

- The utilities shall be responsible for identifying customers that are likely to operate in EITE-eligible industries and that are also likely to have direct emissions below 10,000 $MTCO_2e$. Any entity that believes it is eligible to receive the EITE designation may execute an attestation to the Commission.

- The utilities shall conduct, at minimum, one-time outreach to EITE entities identified as being likely to operate in an EITE-eligible industry and to have annual direct emissions below 10,000 $MTCO_2e$. The purpose of this outreach is to make these customers aware that they may be eligible to receive GHG allowance revenue as an EITE entity. Staff should have authority to review and approve these outreach activities and outreach materials.
- Utility outreach to potential EITE entities for the purposes of identifying EITE-eligible entities should be considered an administrative activity. As such, the utilities should record costs associated with these efforts into the administrative cost memorandum accounts authorized in D.12-12-033. Administrative expenditures will be reviewed in the utility GHG cost and revenue applications ordered by D.12-12-033. No additional marketing (customer outreach and education) budget authority is required.
- Facilities that have direct emissions below 10,000 $MTCO_2e$ per year should have an opportunity to annually demonstrate their eligibility as an EITE.
- Entities found to be eligible should begin receiving allowance revenue for next calendar year, and their eligibility should persist for the duration of the Cap-and-Trade compliance period.
- Customers that successfully demonstrate eligibility in 2015, or the first year when the attestation process is available to customers, should receive an allocation of revenue to address GHG costs associated with 2013, 2014 and 2015 if they have not received a small business California Climate Credit during those years.
- Commission staff should conduct a workshop within 60 days of the effective date of this decision and prepare a workshop report discussing options for the development of the attestation process. The workshop report shall be served on the service list for this proceeding. Staff should:

- Develop the content of the attestation form that entities must sign to demonstrate to the Commission that they primarily operate in an EITE-eligible industry;
- Identify what additional information entities should provide to the Commission as part of their attestations. For example, such information might include utility billing or meter account information necessary to implement the energy-based allocation methodology.
- Define whether an eligible entity's electricity purchases should be defined based on its utility service account information or on the physical boundary of the entity's facility.
- Establish procedures and specific points of responsibility for verifying that attestations are accurate and that entities are actually eligible. These procedures should aim to minimize and to identify fraudulent attestations.
- Address how the utility, or an entity responsible for verifying attestations, should determine whether an entity primarily engages in activities described by an EITE-eligible NAICS Code.
- Address the process to identify and communicate to utilities any customers that should shift from the small business to the EITE category.
- Address the timing by which attestations should be collected and verified each year and by which the utilities and Commission staff should exchange data necessary to return revenue to eligible customers.

- Following receipt of the workshop report, the assigned ALJ shall prepare a proposed decision addressing the attestation process. The approved attestation process should be made publicly available to any interested person by publishing the process on the Commissions website.

6.3. Allocation Methodology for EITE Entities with Annual Emissions Under 25,000 $MTCO_2e$

As discussed earlier in this decision, GHG revenue will be returned to all EITE customers that have direct emissions below 25,000 $MTCO_2e$ according to the energy-based allocation methodology adopted in this decision. Since ARB MRR data about electricity purchases are unavailable for EITE customers with annual direct emissions less than 10,000 $MTCO_2e$, the energy-based allocation methodology for these customers should instead rely upon historic 2008-2010 utility data. This data should include both bundled and unbundled electricity purchases. The energy-based allocation methodology should otherwise remain unchanged for these facilities. No party objected to the use of historical electricity purchases based on 2008 to 2010 utility data. We approve this data source when allocating allowance revenue to facilities with annual direct emissions less than 10,000 $MTCO_2e$, although different data years are appropriate, as specified in Appendix Section 2.5, for facilities that have transitional emissions data.

All data necessary to perform the energy-based allocation for EITE customers with annual emissions less than 10,000 $MTCO_2e$ is available to the utilities. Staff initially recommended that the utilities should be responsible for calculating the revenue allocation for these facilities. Staff also recommended that this allocation should be delivered as an annual bill credit during the same month as all other EITE credits are delivered to eligible customers. The Joint Utilities requested that Commission staff be responsible for undertaking the revenue allocation calculations and for reporting the results to the utilities, which would then disburse the funds to individual customers.

We find that it is more administratively simple and efficient if the Commission's Energy Division, rather than the utilities, undertakes the energy-base allocation calculations for EITE entities that have direct emissions less than 25,000 $MTCO_2e$ per year. Staff will already need to develop tools and processes to calculate the energy-based allocation for covered entities and opt-in covered entities. Therefore, to avoid potentially duplicative efforts, it is reasonable to require Commission staff to collect the necessary data from utilities and perform the revenue allocation calculation for EITE facilities that have direct emissions below 25,000 $MTCO_2e$. Staff should provide the revenue allocation information to the utilities for distribution to the EITE facilities.

7. Allocation of GHG Allowance Revenue to Entities that are Both Small Businesses and EITE

In D.12-12-033, the Commission adopted eligibility criteria for a business to be eligible to receive GHG allowance revenue according to the small business methodology. In their Implementation Plans, which were approved in D.13-12-003, the Joint Utilities proposed to give allowance revenue to customers that meet the criteria for both small business and EITE eligibility as if they were EITE entities rather than small businesses. However, in comments on the Staff Proposal, the Joint Utilities propose to treat customers differently if they have direct emissions below 10,000 $MTCO_2e$. The Joint Utilities now propose that customers that have direct emissions less than 10,000 $MTCO_2e$ and that qualify as small businesses should receive the small business credit by default. If the customer chooses to sign an attestation, the customer's accounts would shift to the EITE designation at the end the year, where it would remain until the next required attestation. The Joint Utilities suggest that this change will significantly reduce administrative burden.

We seek to avoid the duplicative disbursement of GHG allowance revenue to customers that qualify as both small businesses and EITE. The Joint Utilities' proposed deviation from their approved Implementation Plans is reasonable and is adopted. Any customer with direct emissions less than 10,000 $MTCO_2e$ that is eligible to receive GHG allowance revenue as both a small business customer and an EITE shall receive revenue according to the small business GHG revenue allocation methodology adopted in D.12-12-003, as finalized in D.13-12-002, unless and until such customer attests that it is EITE-eligible and prefers to receive allowance revenues as and EITE entity. The EITE attestation process should include a process to identify and communicate to utilities any customers that should shift from the small business to the EITE category.

It is necessary, however, to place appropriate boundaries on the small business and EITE designations to further avoid duplicative disbursement of GHG allowance revenue. A large EITE entity may have multiple accounts, several of which may, on their own, qualify as small business accounts under the definition of small business adopted in D.12-12-033. If an entity is designated as EITE, it should receive its disbursement of GHG allowance revenue according to the EITE formulas adopted herein, and none of the entity's electricity usage should be credited with allowance revenue according to the small business allocation methodology.

8. Method, Timing and Name of EITE GHG Allowance Revenue Return

The Staff Proposal included an initial recommendation that revenue should be returned to EITE entities, by default, as an on-bill credit, which should occur coincident with the first of the two semi-annual non-volumetric residential GHG allowance revenue returns. Staff also proposed various naming options for

the EITE revenue return that would appear on customer bills. By ruling dated October 16, 2013, the Staff Proposal was updated to recommend that GHG allowance revenue be distributed to EITE entities via a third-party disbursement agent that would operate under contract with the Commission. The disbursement agent would return GHG allowance revenue to individual EITE customers in a manner separate from utility bills.

8.1. Confidentiality

The formulas adopted in this decision rely to a significant degree on data that industries report to ARB through its MRR. In particular, the product-based allocation relies on data about each facility's annual product output – information that ARB treats as confidential and business sensitive.

The Commission and ARB have entered into a non-disclosure agreement that allows staff to access MRR data necessary to calculate EITE revenue allocations. Under the terms of this agreement, the Commission has an obligation to treat as confidential any information that ARB considers confidential. We will protect as confidential all MRR or other data it receives from ARB that ARB deems confidential.

In addition, there are instances when industries may need to provide confidential data directly to the Commission if this data is not currently required as part of MRR. Here, we adopt the same provisions used by ARB to protect confidential information in the MRR. Any information that is considered to be a trade secret, as defined in Government Code Section 6254.7, is not a public record and will therefore not be released to the public upon its submission to the Commission.

The initial Staff Proposal envisioned that staff could perform the product, energy and refinery allocation methodologies, and then confidentially convey to

utilities the dollar amount of revenue due to each EITE entity and the utility would credit the EITE's account.

In the case of the product-based allocation methodology and the refinery allocation methodology for simple refineries, if both the confidential dollar amount due to an individual facility and the industry product benchmark were to be publicly disclosed, any individual or private organization could easily determine the facility's annual product output, which is confidential business information. If the result of the calculation were disclosed, it would be a trivial exercise to use the public variables in the equation to calculate the facility's annual product output. Disclosure of product output information could be used by competitors to damage or gain a financial advantage over an industrial facility.

The October 16, 2013 ALJ Ruling updating the Staff Proposal explained that it was possible that each EITE entity's individual revenue return could be subject to disclosure through a Public Records Act[72] request if staff were to share it with a utility. The amended Staff Proposal assumed that the Commission would publicly disclose industry benchmarks of electricity emissions per product output, just as ARB does in its Cap and Trade Regulation. If these benchmarks were to be disclosed along with information about each EITE facility's allowance revenue allocation, any individual could calculate the facility's confidential annual product output.

Because we have an obligation to protect confidential data, and confidential product output information can become publicly disclosed if the

[72] CA Government Code §§ 6250-6276.48

dollar amount of an EITE facility's allowance revenue allocation were to be made public along with information about each industry's product benchmark, the amended Staff Proposal recommended that the Commission contract with a disbursement agent whose primary responsibility would be to issue revenue directly to EITE customers. Because the disbursement agent would operate under direct contract with the Commission, the terms of the Commission's non-disclosure agreement with ARB, along with other existing confidential protections, would extend to the entity under contract. In addition, since an on-bill credit could also be publicly disclosed, staff recommended that the EITE revenue return should occur separate from utility bills.[73]

Under this amended approach, staff would gather MRR data and calculate the amount of revenue each EITE customer should receive in a given year. Staff would then report to the utilities and the disbursement agent an aggregate total amount of revenue needed to implement the revenue return.[74] Staff would also communicate to the disbursement agent the confidential dollar amount due to each EITE facility eligible to receive GHG revenues. The utilities would then transfer the total allotted amount of EITE revenues to the disbursement agent, for distribution to individual EITE customers.

Staff also recommended that the disbursement agent be tasked with collecting and verifying attestations from entities that have direct emissions less than 10,000 $MTCO_2e$ and that wish to be eligible for EITE allowance revenue.

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[73] Though the utilities' privacy tariffs may prohibit them from disclosing this information upon request, the act of this Commission giving trade secret information directly to utilities themselves could jeopardize the confidentiality of this information if sought from the Commission under the Public Records Act.

[74] The total aggregated amount of revenue returned to EITE customers is public information.

It is possible to protect confidential product information from disclosure as long as the Commission does not publicly release industry product benchmarks that are calculated with confidential facility-level MRR data.
Similarly, we also must not publicly release information about the total revenue allocation to each industrial sector, which could be used to calculate the industry benchmarks if an industry's total annual product output were to be calculated though other sources of public data.

Therefore, we find that a disbursement agent is not required to protect confidential business information from disclosure, and that the utilities should be responsible for returning allowance revenue to individual EITE customers. Staff should annually perform the necessary allocation calculations and direct the utilities to return specific dollar amounts of revenue to individual EITE customers. However, both the industry benchmarks of electricity emissions per product output and the total revenue allocation to each sector are confidential and must not be disclosed.

8.2. Timing and Method of Return of GHG Allowance Revenue to EITE Customers

Staff shall calculate each eligible facility's revenue allocation, and the IOUs should be responsible for delivering the revenue allocation payment as an annual bill credit unless an EITE facility that is a covered entity requests that the utility distribute the facility's revenue as a check, rather than a bill credit. EITE facilities that have direct emissions below 25,000 $MTCO_2e/MWh$ should receive their allowance revenue allocation as a bill credit. This approach will minimize administrative complexity while ensuring that EITE facilities that are covered entities are able to receive and make use of their revenue in a timely manner.

We also noted in D.12-12-033 that "the adoption of methodologies that [mirror] the ARB allowance allocation process to Industrial Covered Entities qualifying for Industry Assistance enables us to compensate EITE ratepayers while maintaining the carbon price signal in their rates."[75]

In D.13-12-003, Ordering Paragraph 1, the Commission decided to issue what is now called the residential California Climate Credit in April and October of each year. There may be administrative and outreach and education synergies that justify synchronizing the annual EITE revenue return with the residential Climate Credit to the extent possible. The Large Users argue that GHG allowance revenue should be returned to EITE customers as soon as practicable. The Large Users state that facilities rely on expectations about allowance revenue allocations in planning cycles, and an earlier allocation will enable better and more accurate planning. Furthermore, the Large Users argue that the return of GHG allowance revenue to large EITE customers should not be delayed while the Commission undertakes the verification process for EITE entities with annual emissions less than 10,000 $MTCO_2e$.

The formulas adopted in this decision should enable each industrial facility to make reasonable forecasts about how much revenue it will receive; and after EITE entities receive their first revenue allocation (for 2013, 2014 and 2015, prospectively) they should be able to forecast with a reasonable amount of accuracy how much allowance revenue they will receive in future years. Outreach and education synergies may exist that justify synchronizing the EITE return with the residential California Climate Credit. Therefore, GHG allowance

[75] D.12-12-033 at 101.

revenue should be returned to EITE customers in April of each year in coordination with the the semi-annual residential Climate Credits.

We recognize that the timing of this decision will delay the first revenue allocation until well into 2015, and that some EITE customers that are DA customers may have been incurring carbon pollution costs in their electricity rates since 2013. It is therefore imperative that the first allocation of GHG allowance revenue must be made to EITE customers as soon as possible once all necessary steps are taken to collect data, perform calculations and ensure accurate allocations. The return of GHG allowance revenue should not be delayed for large EITE customers while the Commission develops and administers the attestation process for EITE entities with annual emissions less than 10,000 $MTCO_2e$. Therefore, in 2015, for which the Commission will address GHG costs for 2013, 2014 and 2015 (prospectively), GHG allowance revenue should be returned to each size of EITE customer as soon as practicable. Customers with emissions less than 10,000 $MTCO_2e$ should receive allowance revenue by April 2015 if practicable, but if additional time is needed to resolve the attestation rules for these customers, the first allowance revenue return should occur no later than October 2015 for customers that have been identified by that date. However, in future years, revenue should be returned to EITE customers, regardless of size, in April.

Section 2.7 of the Staff Proposal sets forth a proposed timeline for information and data exchanges necessary with ARB and the utilities to ensure that the distribution of GHG allowance revenue occurs according to the timeline ultimately adopted in this decision. Staff recommends that the EITE revenue return occur once annually in either the February, March or April billing cycle, consistent with when the Climate Credit occurs, and that all IOUs be required to

return revenue according to the same month's billing cycle. Staff should work with ARB to establish a schedule by which all information and data is exchanged to ensure that all EITE entities receive their distribution of GHG allowance revenue according to the distribution date(s) discussed above.

8.3. Name of the EITE GHG Revenue Return

Section 8.1 of the Staff Proposal recommends that the name of the EITE allowance revenue return should be consistent across all utilities and offers a number of possibilities, including: "California Cap-and-Trade Industrial Assistance," "CA Cap-and-Trade Industry Assistance," and "CA Industry Assistance." The Joint Parties encourage the Commission to adopt consistent names for the EITE and small business credit.

We have previously addressed the issue of nomenclature for the small business and residential GHG allowance revenue returns in D.13-12-002 and D.14-01-012, respectively. In D.14-01-012, the Commission granted its Energy Division the authority to change the previously adopted name of the non-volumetric residential GHG allowance revenue return, which was originally named the "Climate Dividend" in D.12-12-033, if new or existing research on education and outreach or consultation with other state agencies, such as ARB, suggested better ways of communicating the source and purpose of the return. The name "California Climate Credit" was ultimately adopted for the non-volumetric residential and small business allowance revenue returns. This name was noticed to the service list of R.11-03-012 on January 28, 2014, and was added into the record of this proceeding via ruling on February 5, 2014.

We adopt a preliminary name of "CA Industry Assistance" for the allowance revenue returned to EITE entities. The name explains the nature of the return as a supplement to the Industry Assistance ARB provides in its Cap-

and-Trade Regulation, and it correctly ascribes the credit to the State of California. However, as has been adopted for the small business and non-volumetric residential GHG allowance revenue return, if new or existing research on outreach and education, or consultation with other state agencies, such as ARB, suggests better ways of communicating the source and purpose of the revenue allocation, the Director of the Energy Division may change the name of the EITE through a written letter noticed to the service list of this or a subsequent rulemaking.

8.4. Education and Outreach

Education and outreach is necessary for EITE customers (as was contemplated in Public Utilities Code Section 748.5(b)). The utilities must conduct, at a minimum, one-time outreach to potential EITE entities identified as being likely to operate in an EITE-eligible industry. The purpose of this outreach is to make these customers aware that they may be eligible to receive GHG allowance revenue as an EITE entity. Staff should have authority to review and approve these outreach activities and outreach materials. Utility outreach to potential EITE entities for the purposes of identifying EITE-eligible entities should be considered an administrative activity. As such, the utilities should record costs associated with these efforts into the administrative cost memorandum accounts authorized in D.12-12-033. Administrative expenditures will be reviewed in the utility GHG cost and revenue applications ordered by D.12-12-033. No additional marketing (customer outreach and education) budget authority is required.

9. Data Requirements and Confidentiality

9.1. Data Requirements and Timing of Data Exchanges

The Staff Proposal sets forth a list of information that would need to be exchanged between the Commission and ARB as well as between the Commission and the utilities as well as a proposed timing of information exchanges in order to distribute GHG allowance revenue to EITE customers in a timely manner.

Staff must work with appropriate entities, including ARB and the utilities, to determine all necessary exchanges of information that must occur and by when such information must be exchanged in order to return allowance revenue by April of each year. Once a schedule has been determined, that schedule must be made publicly available on the Commission's website.

In addition Staff must establish a process to handle EITE customer inquiries regarding the revenue return. Staff should provide information on the Commission's website and all education materials that includes specific contact information to allow EITE customers to get information and understand the revenue allocation is performed and whom they can contact with questions and concerns.

10. Eligibility to Receive EITE GHG Allowance Revenue

As stated earlier in this decision, D.12-12-033 defined an EITE customer as "any entity in an industry that qualifies for Industry Assistance under the [ARB] Cap-and-Trade regulation, regardless of the amount of emissions produced."[76] However, D.12-12-033 found that additional industries may pose a leakage risk

[76] D.12-12-033 at 87.

as a result of the indirect GHG costs they will experience through their electricity purchases, and in D.14-02-003, we adopted a preliminary scope of work and budget to study whether additional industrial sectors, if any, are at risk of emissions leakage. The Commission does not currently have budget authority to conduct the study addressed in D.14-02-003.

In D.14-02-003, we declined to create a safe harbor standard that would judge whether new industrial sectors are reasonably emissions intensive or trade exposed, and it declined to order the utilities to set aside any GHG allowance revenue for industries that may, at a later date, be designated as EITE entities.[77] However, the Commission noted a compelling exception: industrial sectors or subsectors that have the same six-digit NAICS Code as other sectors eligible to receive ARB's Industry Assistance. The Commission opined that it may be appropriate to allocate GHG allowance revenue to these specific industries according to the same timeframe as those already designated as EITE in D.12-12-033 – it should not be necessary to complete the leakage study before granting them allowance revenue - with a provision for the funds to be returned if the Commission ultimately does not extend the EITE designation to these entities after completing the leakage study. The Commission deferred this issue to the present decision.[78]

If a facility operates primarily in an industry that matches a six-digit NAICS Code included in Table 8-1 of ARB's Cap-and-Trade Regulation, as it may be modified over time, and the facility is not a covered entity, it is

[77] *See* D.14-02-003 beginning at 22 for an in-depth discussion on safe harbor and set aside requests.

[78] D.14-02-003 at 24.

reasonable to deem this facility EITE-eligible pursuant to D.12-12-033, even if the industry's activity does not match one of the subsector activities included in this table. For example, Industrial Gas Manufacturing (NAICS Code 325120) is listed in Table 8-1 of ARB's Cap-and-Trade regulation, and two subsector activities – hydrogen gas production and liquid hydrogen production – are explicitly included. However, we find that it is reasonable to deem facilities that engage in other Industrial Gas Manufacturing sub-sector activities eligible for allowance revenue if they are not covered entities. We presume that any industrial sectors that have at least one covered entity were already included in ARB's assessment of industrial leakage risk.[79] If, upon completion of a leakage study, these industrial subsector activities are not found to pose a leakage risk, then the entities participating in those industrial subsector activities that may have previously received GHG allowance revenue as EITE entities will not receive GHG allowance revenue as EITE entities in the future. In order to receive GHG allowance revenue, these industries must provide an attestation, via the same attestation process described earlier in this decision, that they operate in a sector or subsector that has the same six-digit NAICS code as other sectors eligible to receive Industry Assistance. We decline at this time to extend the EITE designation beyond the NAICS Codes already eligible for ARB's Industry Assistance.

[79] *See* background discussions in D.14-02-003 about how ARB evaluated which industrial sectors should be eligible for Industry Assistance. *See* also Appendix K to ARB's Initial Statement of Reasons.

11. Eligibility of Departing Load EITE Customers

In D.12-12-033, the Commission committed to treating EITE facilities similarly, "regardless of whether the EITE entity purchases or consumes electricity from its own CHP facility, a third-party owned CHP facility, or from an IOU or DA provider."[80] The Decision also acknowledged guidance in ARB's Cap and Trade regulation that "allowance revenue shall be used exclusively for the benefit of retail ratepayers of the electrical distribution utility."[81] Given the Commission's policy preferences and limitations placed on the use of allowance revenue, staff noted that it may be necessary to clarify that certain types of EITE facilities that self-generate electricity or purchase electricity entirely from off-site generators are eligible for an allocation of allowance revenue.

Staff argues that the following four classes of facilities should be considered retail customers of the IOUs for the purpose of determining an EITE facility's eligibility for allowance revenue:

- Facilities that are bundled electricity customers of IOUs – they purchase both electricity supply and delivery from the IOU;
- Facilities that are electricity customers of CCAs/DAs/ESPs – they are unbundled IOU customers that buy electricity from a CCA/DA/ESP supplier, but receive electricity delivery from an IOU;
- Facilities that make use of distributed generation, including CHP, from resources located on-site or off-site, and that also procure standby electricity service from the interconnecting IOU;

[80] D.12-12-033 at COL 27.

[81] 17 CCR § 95892(a)

- Facilities that use distributed generation to supply 100% of their electricity demand and that pay departing load charges to an IOU, but that do not purchase standby service from an IOU.

Facilities that purchase bundled, unbundled, or standby service from an IOU receive electricity service under a tariff approved by the Commission, and can reasonably be understood to be retail IOU customers. No party objected to this definition of retail customers of the IOUs. This characterization of retail customers is appropriate for the purpose of returning GHG allowance revenue to EITE entities.

The fourth category - entities that use distributed generation to supply 100% of their electricity demand and that pay departing load charges to an IOU, but that do not procure standby service from an IOU - is cause for disagreement. Staff notes that self-generators may not pay for actual electricity service from an IOU, but they may pay non-by passable departing load charges, including the Public Purpose Program Charge, Nuclear Decommissioning Charges, and other charges associated with historic IOU investments in grid assets or programs established by the Commission that have broad public benefits. Staff suggests that EITE facilities that pay only departing load charges to an IOU, and that do not procure electricity service from an IOU, should nevertheless be eligible for an allocation of revenue afforded by D.12-12-033. Staff's position is supported by the Large Users.

The Joint Utilities disagree; arguing that entities that pay non-bypassable charges, but do not pay stand-by charges to the IOU, are self-generation customers. The Joint Utilities contend that self-generation customers should not receive an allocation of GHG allowance revenue for electricity use because they are receiving a free allowance allocation directly from ARB for onsite electricity

production. Section 4.7.1.1 of this decision explains why ARB's direct allocations are insufficient and self-generators should receive allowance revenue (if they are eligible for the product based allocation) even if they produce all of their electricity onsite.

For the purpose of distributing GHG allowance revenue to EITE customers, an expansive definition of retail customers is warranted. ARB's direct allocation of allowances to IOUs took into consideration emissions associated with CCA/DA/ESP customers as well as self-generation, qualifying facilities, and other resources not controlled by IOUs but that directly serve customers in IOUs' service territories. It is consistent with the stated intent of D.12-12-033, and ARB's regulations, for EITE entities to be eligible for allowance revenue even if they pay only departing load charges to IOUs. Such facilities will receive a direct allocation of allowances from ARB, and they must also receive an allocation of revenue from the Commission to address outstanding leakage risk associated with emissions from electricity purchases, whether those purchases are from an IOU or a non-IOU electricity provider.

The Commission has an obligation to ensure that all EITE entities that can reasonably be considered to be retail customers of the utility receive their fair share of GHG allowance revenue to account for emissions associated with electricity usage. As discussed in Section 4.6.1.4., departing load customers must receive an allocation of revenue from the Commission to address outstanding leakage risk that arises from the use of a sector-wide benchmark variable, which results in an under-allocation of allowances that have an on-site CHP and an over-allocation to entities that purchase their electricity from third parties. Therefore, any departing load entity that pays departing load charges, regardless of whether or not that entity elects to receive stand-by service from the

interconnecting utility, is considered to be a retail customer of the utility for the purposes of distributing GHG allowance revenue for indirect electricity emissions.

12. EITEs in Multiple IOU Service Territories

It is possible for a single EITE facility to span more than one utility service territory, and for a single facility to purchase electricity from more than one utility. To achieve administrative simplicity, and due to limitations of MRR data, staff recommends that GHG allowance revenue be distributed to an EITE entity in proportion to the facility's electricity purchases from each utility. For example, if a facility purchased 30% of its total electricity from PG&E, 50% from SCE, and the remaining 20% from a DA provider, 3/8 (37.5%) of the GHG allowance revenue due to the facility would be paid by PG&E allowance revenue, and 5/8 (62.5%) would be paid by SCE. No party objected to this proposal.

For EITE facilities that operate in multiple utility service territories, GHG allowance revenue will be distributed in proportion to the facility's purchases from each utility on an annual basis. This approach should also apply if a single EITE reporting entity to ARB operates facilities in multiple utility service territories but only reports a single aggregated product output value to ARB.

13. Outstanding Motions

Numerous parties filed motions in Track 1 of this proceeding seeking resolution of a variety of issues. All outstanding motions have been addressed via electronic or written ruling. Any outstanding motions in Track 1 of this proceeding are hereby denied.

14. Safety Considerations

The health and safety impacts of GHG are among the many reasons that the legislature enacted AB 32. Specifically, the Legislature found and declared that global warming caused by GHG "poses a serious threat to the economic well being, public health, natural resources, and the environment of California. The potential adverse impacts of global warming include the exacerbation of air quality problems, a reduction in the quality and supply of water to the state from the Sierra snowpack, a rise in sea levels resulting in the displacement of thousands of coastal businesses and residences, damage to marine ecosystems and the natural environment, and an increase in the incidences of infectious diseases, asthma, and other human health-related problems."[82]

This decision implements a key part of the GHG reduction program envisioned by AB 32 and Public Utilities Code Section 748.5 and, as a result, will improve the health and safety of California residents.

15. Categorization and Need for Hearing

In the September 1, 2011, Scoping Memo, the Assigned Commissioner confirmed the categorization of the proceeding as ratesetting and set forth a process by which parties could request hearing. No requests for hearing were received, and all issues in Track 1 of this proceeding were addressed through proposals, workshops, and comments. This decision confirms the determination that evidentiary hearings are not needed in Track 1 of this proceeding.

[82] AB 32 Findings and Declarations.

16. Comments on Proposed Decision

The proposed decision of ALJ Halligan in this matter was mailed to the parties in accordance with Section 311 of the Public Utilities Code and comments were allowed under Rule 14.3 of the Commission's Rules of Practice and Procedure. Comments were filed on December 8, 2014, by CCC, the California Farm Bureau Federation, the Food Processors, CMTA, PG&E, SCE, SDG&E, EPUC, CLECA, Tesoro, and USS-POSCO. Reply comments were filed on December 15, 2014 by SCE, EPUC, CLECA, and USS-POSCO.

17. Assignment of Proceeding

Michael R. Peevey is the assigned Commissioner and Julie M. Halligan and Melissa K. Semcer are the assigned ALJs in this proceeding.

Findings of Fact

1. In D. 12-12-033 the Commission adopted a framework of rules about how the investor-owned electric utilities should distribute allowance revenue in accordance with ARB's Cap-and-Trade Regulation and the parameters of Public Utilities Code Section 748.5.

2. Public Utilities Code Section 748.5 requires, among other things, that the Commission provide a direct return of electric utility allowance revenue to "emissions-intensive and trade-exposed" (EITE) entities.

3. For the purpose of allocating GHG allowance revenue, D.12-12-033 defined EITE to mean those entities in industrial sectors that qualify for Industry Assistance under ARB's Cap-and-Trade Regulation, regardless of the amount of emissions produced. These industries are explicitly listed by NAICS Code in ARB's Cap-and-Trade Regulation.

4. In D.12-12-033 the Commission found that entities with annual direct emissions levels less than 25,000 $MTCO_2e$ that operate in sectors eligible for ARB

Industry Assistance should be designated as EITE and must voluntarily opt-in to the Cap-and-Trade program in order to be eligible for allowance revenue as EITEs.

5. D.12-12-033 allowed staff and parties to evaluate whether there are effective ways to allow EITE entities that have annual direct emission less than 25,000 $MTCO_2e$ to receive allowance revenue without opting-in to the Cap-and-Trade program.

6. The purpose of the EITE allowance revenue allocation is to provide transition assistance to address the risk that industrial production and GHG emissions could shift, or leak, out of California. The formulas and implementation details in the Staff Proposal build on the appendices to D.12-12-033 and are substantially based on similar methodologies present in ARB's Cap-and-Trade Regulation that specify what amount of allowances entities are eligible to receive for industry assistance.

7. In D.12-12-033 the Commission expressed a preference that its EITE revenue allocation methodologies should closely mirror ARB's Industry Assistance allocation methodologies.

8. ARB's Regulation for the Mandatory Reporting of Greenhouse Gas Emissions (MRR or Mandatory Reporting Regulation), 17 CCR § 95100 *et seq.*, is the mechanism by which industries report energy use, product output and emissions data, among other information, necessary for ARB to calculate a facility's compliance obligation under Cap and Trade.

9. ARB identified which industrial sectors qualify for Industry Assistance by conducting a study that classifies industries by high, medium or low leakage risk.

10. ARB's assignment of leakage risk is applicable to the EITE allocation formulas approved in this decision because ARB's assessment of leakage risk considered indirect emissions associated with electricity purchases.

11. ARB's industry assistance factors are directly tied to each industry's leakage risk classification, and are defined by industry in Table 8-1 of its Cap-and-Trade Regulation.

12. ARB may revise Table 8-1 of its Cap-and-Trade Regulation in the future to include new industries and industrial activities or to adjust industry leakage risk classifications and assistance factors.

13. ARB's preferred method for allocating allowances for industry assistance is via a product- based methodology, which relies on the development of emissions intensity benchmarks that reflect industrial sector-wide GHG emissions released per unit of product output.

14. ARB's product-based benchmark methodology rewards efficient facilities relative to inefficient facilities; it ensures that industries have a strong incentive to operate efficiently; and it also allows an individual industrial facility's annual allowance allocation to fluctuate in proportion to its annual product output.

15. Industries that receive an allowance allocation according to a product-based methodology are listed in Table 9-1 of ARB's Cap-and-Trade Regulation, which may be modified over time.

16. When calculating product-based benchmarks, ARB generally relied on a historical period of 2008-2010, with some variability in instances when different data were necessary to establish a baseline benchmark.

17. ARB does not update its product benchmarks regularly over time.

18. ARB applies a 90% stringency factor to the product based allocation methodology, except that it applies a "best-in-class" approach for sectors with

one covered entity or in which no covered entity is at least as efficient as the benchmark.

19. A deviation from ARB's stringency approach would disadvantage facilities that choose to generate their own electricity on-site and advantage those facilities that buy electricity rather than generate it on-site.

20. Parties supported the use of 2008-2010 MRR data when developing product-based benchmarks of electricity purchases per unit of product output.

21. The product-based allocation methodology included in Appendix A is substantially based on ARB's comparable methodology.

22. ARB's energy-based allocation methodology is based on a fixed historical baseline amount of direct emissions by facility.

23. ARB relies on a historical period of 2008-2010 MRR data when calculating energy-based historical benchmarks.

24. ARB only applies its energy-based allocation methodology to those industries for which ARB does not grant allowances according to a product-based allocation methodology or a refinery methodology.

25. The energy-based allocation methodology included in Appendix A is substantially based on ARB's comparable methodology.

26. Staff recommended and parties supported the use of an energy-based allocation methodology for Cap-and-Trade covered entities and opt-in covered entities in industries that currently receive an energy-based allocation of allowances from ARB.

27. ARB does not grant allowances to industrial facilities that have direct emissions below 25,000 $MTCO_2e$ unless those facilities have opted into the Cap-and-Trade Regulation and are in industries eligible for ARB Industry Assistance.

28. ARB's Mandatory Reporting Regulation does not currently collect product output data from entities that have annual direct emissions between 10,000 $MTCO_2e$ and 25,000 $MTCO_2e$ unless they opt-in to the Cap-and-Trade Regulation. The same data limitations apply to entities that have direct emissions less than 10,000 $MTCO_2e$ per year.

29. It is possible to implement the energy-based allocation methodology with MRR data for entities that have direct emissions between 10,000 $MTCO_2e$ and 25,000 $MTCO_2e$. To implement the energy-based allocation methodology for facilities that have annual direct emissions less than 10,000 $MTCO_2e$, the Commission needs to collect data from the investor-owned utilities about an entity's electricity use.

30. It would be burdensome for the Commission to collect and verify annual product output data from entities that are not otherwise required to report this data under ARB's MRR.

31. It is burdensome to require entities with direct emissions between 10,000 $MTCO_2e$ and 25,000 $MTCO_2e$ to opt-in to the Cap-and-Trade Regulation for the sole purpose of becoming eligible to receive allowance revenue for indirect emission costs in electricity purchases.

32. Parties agreed that the energy-based allocation methodology should apply to all entities in EITE-eligible industries that have annual direct emissions less than 10,000 $MTCO_2e$.

33. Entities that directly emit less than 10,000 $MTCO_2e$ per year do not have a reporting obligation under MRR.

34. Utilities manually classify business customers by NAICS Code, but these classifications are not independently verified and are made based on a utility's judgment.

35. No party opposed staff's proposal that entities with direct emissions less than 10,000 $MTCO_2e$ per year should be required to sign an attestation to demonstrate that they primarily engage in activities described by an EITE-eligible NAICS Code.

36. The electric utilities have memorandum accounts that enable them to track administrative and outreach costs incurred to implement D.12-12-033.

37. MRR data and electric utility data can be used to identify customers that are likely to operate in EITE-eligible industries, including those likely to have direct emission less than 10,000 $MTCO_2e$ per year.

38. It is more efficient if Energy Division staff, rather than the utilities, undertakes the energy-based allocation methodology calculations for EITE entities that have direct emissions less than 25,000 $MTCO_2e$ per year.

39. ARB's Cap-and-Trade Regulation uses one set of refinery allocation formulas for the first Cap-and-Trade compliance period and a different methodology for the second and third compliance periods.

40. The refinery allocation methodology recommended for use during the first Cap and Trade compliance period substantially mirrors the methodology that ARB has adopted for this same period and is supported by the parties.

41. ARB approved amendments to its Cap-and-Trade Regulation on April 25, 2014, which change the refinery allocation methodology for the second and third compliance periods from a carbon dioxide weighted tonne approach to a complexity weighted barrel approach.

42. There is no difference in administrative burden to allocate allowance revenue before costs are incurred rather than after costs are incurred.

43. An advance allocation provides industrial entities with an additional level of transition assistance without any apparent detriment to other ratepayers or threats to the integrity of the Cap-and-Trade Program.

44. ARB's industry assistance methodologies result in an allocation of allowances, but the Commission must allocate allowance revenue; thus, a dollar conversion factor must be introduced into the Commission's allocation methodologies to convert emissions into a dollar equivalent.

45. Staff proposed to define the dollar conversion factor for a given year based on the weighted average of ARB's quarterly allowances auctions in that same year.

46. The weighted average of ARB's quarterly allowance auctions does not necessarily reflect the GHG costs embedded in daily wholesale electricity prices.

47. The California Independent System Operator (CAISO) publishes a daily Greenhouse Gas Allowance Index Price, which represents the current cost of buying an allowance, the replacement cost of using an allowance already held, as well as the opportunity cost of not generating and selling the allowance.

48. The use of a prospective revenue allocation requires that the most recent year's dollar conversion factor should be used in the allocation formulas, since the actual dollar conversion factor will not be known until the end of the calendar year. The true-up formulas included in Appendix A to this decision illustrate how to reconcile the actual dollar conversion factor with the most recent year's factor.

49. The cap adjustment factor included in ARB's Cap-and-Trade Regulation reflects the rate at which California's GHG emissions cap will decline over time.

50. Table 9-2 of ARB's Cap-and-Trade Regulation includes a Cap Adjustment Factor for Sectors with Process Emissions Greater than 50%.

51. Process emissions are direct emissions that are intrinsic to the chemistry of an industrial process wherein compounds undergo chemical transformations that release GHG emissions. Process emissions are not related to the direct combustion of fuel or the emissions embedded in electricity.

52. Indirect emissions associated with electricity purchases or on-site electricity generation are not process emissions.

53. The Large Users admit that no process emissions are at issue in Gerdau's case.

54. ARB allocates allowances to eligible industries based on benchmarks of direct emissions from industrial facilities.

55. To establish these benchmarks, ARB converts an industrial facility's energy use into emissions through the use of emission factors.

56. ARB's industry assistance methodologies include an emissions factor of 0.431 $MTCO_2e/MWh$ for electricity that industrial entities export to the grid from on-site electricity generators.

57. ARB has not established an emission factor in its Cap-and-Trade Regulation or MRR that represents the emissions embedded in electricity that investor-owned utilities, CCAs, ESPs or POUs sell to end-use customers, otherwise known as "indirect emissions".

58. The most administratively simple option is to establish a statewide emission factor that would apply to all electricity purchases.

59. ARB's 0.431 $MTCO_2e/MWh$ emission factor is substantially higher than the average portfolio emissions of any single investor-owned utility. A single industrial facility may purchase electricity from a range of sources: one or more investor-owned utilities, DAs, ESPs, or POUs, and they may self-generate electricity or purchase it from an off-site CHP facility.

60. A statewide 0.431 $MTCO_2e/MWh$ emission factor does not take into account the fact that a portion of IOU, CCA and DA providers' electricity consists of zero-emission electricity due to their Renewable Portfolio Standard (RPS) obligations.

61. In D.11-09-015 the Commission approved an emission factor of 0.379 $MTCO_2e/MWh$ to use when valuing the GHG emissions of avoided grid electricity purchases. This factor is based on the estimated emissions factor of a marginal natural gas electricity generator (0.432 $MTCO_2e/MWh$, which was included ARB's AB 32 Scoping Plan (2008)), discounted downward by 20% to reflect renewable resources required under the RPS statute as of 2012, and adjusted upward by 7.8% to account for avoided transmission and distribution line losses.

62. D.11-09-015 reasoned that an emission factor of 0.379 $MTCO_2e/MWh$ is conservative because ARB's emission factor for a marginal electricity generator was based on 2002 to 2004 gas-fired plants, which do not reflect the lower remission rate of newer gas-fired plants used after 2004, and also because the renewable content of electricity will increase to 33% by 2020, which is likely to further reduce the emissions of avoided grid purchases.

63. RPS requirements apply equally to investor-owned utilities, CCAs, ESPs and POUs.

64. PG&E has a significant amount of zero-emission hydroelectric and nuclear generation resources that are unavailable to other load serving entities in California, and its portfolio emissions are significantly lower than those of SCE or SDG&E.

65. For the purpose of allocating allowance revenue to EITEs, it is reasonable to apply an emission factor of 0.379 $MTCO_2e/MWh$ for EITE electricity

purchases from all investor-owned utilities, including CCAs, ESPs and POUs, with the exception of PG&E.

66. For EITE electricity purchases from PG&E, it is reasonable to use the utility-specific emission factor of 0.291 $MTCO_2e/MWh$. This approach is unlikely to penalize efficient facilities or reward inefficient facilities to a degree that would distort a facility's natural incentives to operate efficiently.

67. Although it is technically possible to develop emission factors for each CHP facility, this effort would require significant time and analysis to determine what portion of a CHP's facility's total emissions should be allocated between electricity production and useful steam productions

68. Staff recommended, and no party opposed, that electricity that EITE entities purchase from off-site CHP facilities should be assigned the same emission factor – 0.431 $MTCO_2e/MWh$ – that ARB assigns to electricity that on-site electricity generators export to the grid.

69. ARB allocates allowances to POUs in the same manner as it allocates allowances to IOUs. However, POUs can apply those allowances to their Cap-and-Trade compliance obligation. The Commission has no insight into how POUs use their allowances and any revenue they may generate, and as a result the Commission cannot conclude that POU electricity rates include a carbon price signal.

70. It is consistent with D.12-12-033 to consider an EITE entity's total electricity purchases, including those from investor-owned utilities, off-site CHP facilities and other third parties, when developing product benchmarks.

71. It is consistent with D.12-12-033 to exclude the electricity than an EITE facility purchases from a POU when calculating that facility's historic electricity purchases as part of the energy-based methodology.

72. In the product-based methodology, the Commission has a choice to develop a product benchmark that represents either electricity intensity (electricity use per unit of product output) or electricity emissions intensity of product output (electricity emissions per product output).

73. An electricity intensity benchmark best reflects ARB's product benchmarking methodology.

74. Electricity produced on-site should not count as electricity purchases for the purpose of allocating allowance revenue to EITEs because ARB included these emissions in its calculation of allowances for direct emissions.

75. In ARB's Cap-and-Trade Regulation, some industrial sectors have product-based emissions efficiency benchmarks for subsector activities.

76. In cases when a single industrial facility creates products in more than one industrial subsector, ARB's MRR data about electricity purchases may not provide insight into the facility's electricity purchases for each subsector activity.

77. Three methods to estimate electricity purchases by subsector activity exist, each of which may be appropriate for different sectors: 1) use relative natural gas use by subsector activity as a proxy for electricity purchases by subsector; 2) use voluntarily reported auditable data of electricity use by subsector activity; or 3) use relative product output as a basis for splitting electricity purchases by subsector activity. ARB has developed percentage allocation factors that apportion total natural gas use by industrial subsector activity.

78. Auditable internal records of a facility's electricity use by subsector activity may not be available for 2008 to 2010, in which case it is appropriate to use the three years of data nearest to 2008 to 2010.

79. The development of facility-specific product benchmarks in cases when two or more facilities that engage in a single subsector activity would be a significant deviation from ARB's benchmarking methodologies.

80. The Cap-and-Trade Regulation amendments that ARB approved on April 25, 2014, included revisions to Sections 95891(a)(3) and 95891(c)(3) of the Cap-and-Trade Regulation that affect the eligibility for Industry Assistance for covered entities or opt-in covered entities and clarify when the energy-based methodology should be used.

81. When allocating allowances to opt-in covered entities without historical baseline emissions data (Cap-and-Trade Regulation § 95891(c)(3)(A)), ARB relies on estimates of fuel use, steam sales, and electricity sales. The Commission can return allowance revenue to these facilities if ARB develops estimates of such facilities' electricity purchases. If ARB does not have estimates of electricity purchases, it will not be administratively feasible for the Commission to produce these estimates, and it will not be possible to return allowance revenue to these facilities until ARB has verified MRR data for these facilities.

82. A public timeline and yearly schedule for the EITE revenue allocation process, including information about the timing for data exchanges, attestation and calculations would be useful to EITE entities, agencies and others who may be involved in or affected by the EITE revenue allocation methodology.

83. The product-based and refinery allocation methodologies rely on MRR data about each facility's annual product output that ARB treats as a confidential trade secret.

84. The Commission has an obligation to treat as confidential any information it receives from ARB that ARB considers confidential.

85. Knowledge of the amount of allowance revenue that individual EITE entities receive pursuant to the product-based methodology or the refinery methodology would result in the ability to calculate confidential information about a facility's annual product output if the Commission were to also release information about product benchmarks.

86. The methodologies and formulas adopted in this decision allow the utilities to return allowance revenue to EITE facilities as an on-bill credit or a check without jeopardizing the confidentiality of ARB confidential data and EITE facility information that is a trade secret, such as annual product output.

87. Given the length of time some EITE customers may have been incurring carbon pollution costs in their electricity rates, it is imperative for the Commission to ensure that EITE customers receive their first allocation of allowance revenue as soon as practicable.

88. The GHG costs and allowance revenues that the IOUs deferred from inclusion in rates for 2013 and part of 2014 accrued interest.

89. Using the same "California Climate Credit" nomenclature for the EITE revenue return could cause confusion.

90. Using the name "CA Industry Assistance" for the allowance revenue that will be returned to EITE entities explains the nature of the return as a supplement to the Industry Assistance ARB provides in its Cap-and-Trade Regulation, and correctly ascribes the credit to the State of California.

91. To return allowance revenue to EITEs entities, Energy Division will need to collect substantial quantities of data and information from ARB, the utilities, and EITE entities. For Energy Division to implement the EITE revenue return, it may be necessary for industries to report confidential trade secrets directly to Energy Division if this data is not currently required as part of ARB's MRR. For

example, an EITE entity may need to report electricity use by subsector activity, a data field not currently required by ARB's MRR.

92. The California Public Records Act (Government Code Section 6254.7) defines trade secrets.

93. Table 8-1 of ARB's Cap-and-Trade Regulation contains a list of six-digit NAICS Codes of industrial sectors that are eligible for Industry Assistance. It is possible that some entities may match one of these NAICS Codes at the six-digit level, but the entity's specific industrial activity may not be referenced in this table. Such entities are uniquely situated because ARB has previously assessed the leakage risk for at least one particular subsector of such industries, but ARB has not yet evaluated other subsectors of these industries.

94. When allocating allowances to the investor-owned utilities, ARB took into consideration emissions associated with investor-owned utilities, including unbundled CCA and DA customers, customers that self-generate electricity, qualifying facilities, and other resources not directly controlled by investor-owned utilities but that serve customers in investor-owned utilities' service territories.

95. For the purpose of allocating GHG allowance revenue to eligible EITE entities, it is consistent with D.12-12-033 and ARB's regulations to consider the following classes of customers to be retail customers of an investor-owned utility: entities that are bundled or unbundled customers of an investor-owned utility; entities that make use of on-site generation resources and that also pay for standby service from an investor-owned utility; and entities that use on-site generation to supply 100% of their electricity demand and that pay departing load charges, even if they do not buy standby service from an investor-owned utility.

96. It is possible for a single EITE entity to span more than one utility service territory and to purchase electricity from more than one utility. In such cases, allowance revenue can be distributed to the EITE entity in proportion to the facility's electricity purchases from each utility.

Conclusions of Law

1. The Commission's EITE allocation methodologies should mirror ARB's allocation methodologies, making exceptions only when ARB's methodologies present unnecessary or administratively unworkable complications when applied to emissions from electricity purchases; necessary data are unavailable; or policy or legal questions arise that ARB did not address in the scope of its regulations. Additionally, the Commission should prioritize administrative simplicity when presented with competing policy choices that have generally commensurate public benefits.

2. ARB's leakage risk classifications and assistance factors by industrial activity defined in Table 8-1 of its Cap-and-Trade Regulation – high, medium or low – should apply equivalently to each EITE industry eligible for allowance revenue from the Commission.

3. Any revisions to Table 8-1 of ARB's Cap-and-Trade Regulation should be reflected in the Commission's EITE allowance revenue allocation methodologies on a prospective basis without the need for additional Commission action; such changes are ministerial in nature.

4. It is reasonable to use a product-based methodology to allocate allowance revenue to EITE entities that are covered entities or opt-in covered entities under Cap-and-Trade and that operate in industries that receive allowances from ARB according to a product-based methodology. These industries are included in Table 9-1 of ARB's Cap-and-Trade Regulation, as it may be modified over time.

5. If ARB revises Table 9-1 of its Cap-and-Trade Regulation to include product benchmarks for additional industries, the Commission should develop equivalent product benchmarks of electricity purchases per unit of product output for these new industries.

6. The Commission should use 2008-2010 MRR data in its product-based, energy-based, and refinery allocation methodologies.

7. The utilities should be responsible for collecting and managing attestations to the Commission from customers that seek to demonstrate their eligibility as EITE entities.

8. Utility efforts to notify EITE-eligible customers, and customers that are likely to be EITE-eligible, of their potential eligibility for allowance revenue is an administrative cost that can be recorded in the utilities' administrative cost memorandum accounts authorized in D.12-12-033.

9. Product benchmarks and historical energy-based benchmarks should be calculated once and should be updated only if ARB substantially revises its comparable benchmark methodologies.

10. Product-based industry benchmarks should take into account all California facilities in an industrial sector, not solely those in an investor-owned utility's territory.

11. The Commission should mirror ARB's use of a stringency factor in a product based allocation methodology, and in cases when ARB applies a "best-in-class" approach for sectors with one covered entity or in which no covered entity is at least as efficient as the industry product benchmark the Commission should also use a "best-in-class" approach.

12. For Cap-and-Trade covered entities and opt-in covered entities the energy-based allocation methodology should apply to those industries for which ARB

does not grant allowances according to a product-based or refinery allocation methodology.

13. The benchmarks used in the energy-based allocation methodology should represent historical electricity emissions per facility, and should exclude electricity purchases from POUs because POUs are responsible for compensating their EITE customers.

14. The energy-based allocation methodology should apply to all EITE eligible entities that have annual direct emissions between 10,000 $MTCO_2e$ and 25,000 $MTCO_2e$ and that are not opt-in covered entities.

15. If ARB collects product output data from EITE eligible entities that have annual direct emissions between 10,000 $MTCO_2e$ and 25,000 $MTCO_2e$ in its Mandatory Reporting Regulation, the product-based methodology should apply to these entities.

16. The Commission should use 2008 to 2010 MRR data when calculating fixed historical energy-based benchmarks for entities that have annual direct emissions equal to or greater than 10,000 $MTCO_2e$ and that report to ARB under its MRR.

17. The energy-based allocation methodology should apply to all EITE-eligible entities that have annual direct emissions less than 10,000 $MTCO_2e$.

18. The Commission should use 2008 to 2010 investor-owned utility data when calculating historical energy-based benchmarks for EITE eligible entities that have annual direct emissions less than 10,000 $MTCO_2e$, except that more recent data can be used if data from 2008 to 2010 are unavailable.

19. The refinery allocation methodology for use during the first compliance period is included in Appendix A and is based on the refinery methodology that ARB uses during the first compliance period.

20. The Commission should allocate allowance revenue to EITE entities in advance: near the beginning of a year to address emissions from electricity purchases expected to be made over the course of the year.

21. If ARB substantially revises the portions of its Cap-and-Trade Regulation that address industry assistance methodologies, Energy Division should prepare for the Commission's consideration a resolution recommending any necessary changes to the EITE allocation methodologies adopted in this decision.

22. The Commission's EITE allocation methodologies should include a dollar conversion factor, which should be defined as the annual average of CAISO's daily Greenhouse Gas Allowance Index Prices. This factor should apply to all EITE entities regardless of their electricity provider.

23. It is reasonable to use the same dollar conversion factor for all EITE entities, regardless whether the EITE entity produces electricity on-site or purchases electricity from an investor-owned utility or other electricity provider.

24. The most recent year's dollar conversion factor should be used when calculating prospective revenue returns, and this factor should be reconciled with the actual factor when true-ups occur. The true-ups included in Appendix A to this decision illustrate how to reconcile the actual dollar conversion factor with the most recent year's factor.

25. The Commission's EITE allocation methodologies should use Cap Adjustment factors that exactly match the Cap Adjustment Factor for All Other Direct Allocation defined in Table 9-2 of ARB's Cap-and-Trade Regulation. These cap adjustment factors should apply to all EITE entities.

26. The Large Users' and Gerdau's proposal that Gerdau should be allowed to use ARB's Cap Adjustment Factor for Sectors with Process Emissions Greater than 50% lacks merit and should be denied.

27. For the purpose of allocating allowance revenue to eligible EITE facilities, it is reasonable to apply an emission factor of 0.291 $MTCO_2e/MWh$ for electricity purchased from PG&E, and 0.379 $MTCO_2e/MWh$ for electricity purchased from all other investor-owned utilities, publicly owned utilities and energy service providers, and community choice aggregators.

28. It is reasonable to assign the same emission factor for off-site CHP – 0.431 $MTCO_2e/MWh$ – that ARB assigns to electricity that on-site electricity generators export to the grid.

29. When calculating product-based benchmarks for EITE industries, it is reasonable and consistent with D.12-12-033 to consider an EITE entity's total electricity purchases, including those from investor-owned utilities, POUs, off-site CHP facilities and other third parties.

30. Under the product-based allocation methodology, the Commission should discount the annual product output variable for each facility by the percentage of the facility's total electricity purchases that are from publicly-owned utilities because POUs are responsible for compensating their EITE customers. This discounting should be based on the most recent MRR data available at the time Staff conducts the allocation.

31. The Commission's product-based benchmarks should take into account all California facilities in an industrial sector, not solely those in an investor-owned utility's territory, even though the Commission will only allocate revenue to facilities that operate in an investor-owned utility's territory.

32. Electricity produced on-site should not count as electricity purchases for the purpose of calculating the electricity intensity benchmark.

33. It is reasonable to use ARB's MRR data as inputs when calculating product, energy and refinery allocations in cases when MRR data is available.

34. It is reasonable to apportion a facility's electricity purchases to each subsector activity according to the same relative natural gas use factors that ARB used when allocating allowances to the facility for direct emissions. However, for the Rolled Steel Shape Manufacturing Sector (NAICS Code 331221) it is reasonable to apportion total electricity purchases to subsectors by using a combination of natural gas use factors, auditable electricity meter data, and relative subsector product output: for hot rolled steel sheet production, in which only one company currently operates, it is appropriate to use natural gas use factors; for tin steel plate production, in which a different company operates, it is reasonable to use auditable electricity meter data; and for the remaining three rolled steel shape manufacturing subsectors in which two companies currently operate, it is reasonable to use relative subsector product output. For the Crude Petroleum and Natural Gas Extraction sector (NAICS Code 211111) it is reasonable to apportion a facility's electricity purchases to subsectors based on the relative subsector product output.

35. The development of facility-specific product benchmarks in cases when two or more facilities that engage in a single subsector activity would be a significant deviation from ARB's benchmarking methodologies that is not justified by a lack of perfect data about a facility's electricity purchases by subsector activity.

36. The Commission's allowance revenue allocation methodologies for EITEs should reflect the April 25, 2014, Cap-and-Trade Regulation amendments to Sections 95891(a)(3) that affect covered entities that are new entrants. However, the Commission should not apply the provisions in Section 95891(a)(3) to facilities that have annual direct emissions less than 25,000 $MTCO_2e$ and that are not opt-in covered entities.

37. The Commission's allowance revenue allocation methodologies for EITEs should reflect the April 25, 2014, Cap-and-Trade Regulation amendments to Sections and 95891(c)(3) that affect new entrants.

38. When allocating allowances to opt-in covered entities without historical baseline emissions data (Cap-and-Trade Regulation § 95891(c)(3)(A)), the Commission should only return allowance revenue to these facilities if ARB develops and provides an estimate of each such facility's annual electricity purchases. The Commission should not apply the terms of this Cap-and-Trade Regulation section to facilities with annual direct emissions less than 25,000 $MTCO_2e$ unless the facilities are opt-in covered entities.

39. The stringency factor should be applied to all industries that receive a product-based allocation, except where ARB has determined that the "best-in-class" approach should be used.

40. Facilities that close or are no longer engaged in EITE-eligible industrial activities should not receive an allocation of GHG allowance revenue.

41. To be eligible for EITE allowance revenue, entities with direct emissions less than 10,000 $MTCO_2e$ per year should be required to attest to the Commission that they primarily engage in activities described by an EITE-eligible NAICS Code.

42. The investor-owned utilities should be responsible for collecting, managing and verifying the attestations from entities with direct emissions less than 10,000 $MTCO_2e$ per year on behalf of the Commission.

43. Entities should have an opportunity to attest to their EITE eligibility once per year; eligibility should commence at the beginning of the next year; and entities that successfully demonstrate their EITE-eligibility should be cross-checked with utility records to ensure that customers do not receive both

an EITE revenue allocation and a small business California Climate Credit. Customers that successfully demonstrate eligibility in 2015, or the first year when the attestation process is available to customers, should receive an allocation of revenue to address GHG costs associated with 2013, 2014 and 2015 if they have not received a small business California Climate Credit during those years.

44. It is reasonable to delegate responsibility to Energy Division to determine an appropriate method to identify customers that are likely to operate in EITE eligible industries and that are also likely to have direct emissions below 10,000 $MTCO_2e$ per year, all of whom the utilities should notify at least once about their option to attest to their EITE-eligibility and to receive allowance revenue. Costs for this outreach should be considered administrative in nature and should be tracked in the utilities' administrative cost memorandum accounts authorized in D.12-12-033.

45. It is reasonable to delegate responsibility to Energy Division to perform the energy-based allocation calculations for EITE entities that have direct emissions less than 25,000 $MTCO_2e$ and are not covered entities or opt-in covered entities.

46. Energy Division should be responsible for the allocation calculations for all EITE entities that have direct emissions below 25,000 $MTCO_2e$.

47. A facility that receives an EITE allocation should not also receive a small business California Climate Credit for any of the electricity meters associated with the EITE-eligible facility. For 2013-2015, the amount of allowance revenues received by an EITE-eligible entity should reflect a deduction of the amount of small business California Climate Credit received for any of the electricity meters associated with the EITE-eligible entity.

48. Entities that have annual direct emissions less than 10,000 $MTCO_2e$ and that qualify as a small business under D.12-12-033 should receive the small business credit by default.

49. If an entity that has annual direct emissions less than 10,000 $MTCO_2e$ successfully attests that it is EITE-eligible, it should begin receiving an EITE allocation the next year, and at the beginning of the next year it should cease receiving a small business climate credit for as long as it is EITE-eligible.

50. Energy Division should be responsible for calculating the amount of revenue due to each EITE facility.

51. The investor-owned utilities should be responsible for delivering revenue to each EITE facility according in amounts directed by Energy Division. This allocation should be delivered by default as an annual bill credit, although it is appropriate for EITE facilities that are covered entities to have an opportunity to request a check rather than an on-bill credit. EITE facilities that have direct emissions below 25,000 $MTCO_2e/MWh$ should receive their allowance revenue allocation as a bill credit, with an option to "cash out" any remaining bill credit by receiving a check from the utility.

52. EITE entities should receive their revenue allocation for 2013 and 2014 costs as soon as practicable. For years 2015 and later, the revenue return should occur by April of each year.

53. EITE entities should receive interest, calculated at the three month commercial paper rate, on their revenue allocation for 2013.

54. The Commission should adopt the name "CA Industry Assistance" for the allowance revenue that will be returned to EITE entities. If new or existing research on outreach and education, or consultation with other state agencies, such as ARB, suggests better ways of communicating the source and purpose of

this revenue allocation, the Director of the Energy Division may change this name through a written letter noticed to the service list of this or a subsequent rulemaking.

55. The Commission should protect as confidential any trade secrets, as defined in the California Public Records Act (Government Code Section 6254.7,) that EITE entities may need to report to in order to implement the EITE revenue return.

56. Information regarding each industry product benchmark should remain confidential because knowledge of the amount of allowance revenue that individual EITE entities receive pursuant to the product-based methodology or the refinery methodology would result in the ability to calculate confidential information about a facility's annual product output if the Commission were to release information about product benchmarks.

57. It is reasonable to deem an entity EITE-eligible if the entity operates primarily in an industry that matches a six-digit NAICS Code included in Table 8-1 of ARB's Cap-and-Trade Regulation, even if the industry's activity does not match one of the subsector activities included in this table.

58. To receive allowance revenue, entities that operate primarily in an industry that matches a six-digit NAICS Code included in Table 8-1 of ARB's Cap-and-Trade Regulation must provide an attestation through the process described in Section 7.

59. For the purpose of allocating GHG allowance revenue to eligible EITE entities, the following classes of customers should qualify as retail customers of an investor-owned utility: 1) entities that are bundled or unbundled customers of an investor-owned utility; 2) entities that make use of on-site generation resources and that also pay for standby service from an investor-owned utility;

and 3) entities that use on-site generation to supply 100% of their electricity demand and that pay departing load charges, even if they do not buy standby service from an investor-owned utility.

60. In cases when an EITE entity purchases electricity from more than one investor-owned utility, it should receive allowance revenue from each utility in proportion to its relative electricity purchases from each utility.

61. Any outstanding motions pertaining to Track 1 of R.11-03-012 should be denied.

62. All outstanding issues pertaining to Track 1 of R.11-03-012 have been addressed in this or previous decisions. Track 1 of R.11-03-012 is complete; R.11-03-012 should remain open to address issues in other tracks.

O R D E R

IT IS ORDERED that:

1. Pacific Gas and Electric Company, Southern California Edison Company, San Diego Gas & Electric Company, Liberty Utilities (CalPeco Electric) LLC, and PacifiCorp shall file a Tier 2 Advice Letter within 60 days of the effective date of this decision to update their tariffs to allow for the disbursement of greenhouse gas allowance revenue to eligible emissions-intensive and trade-exposed entities.

2. The methodologies to allocate greenhouse gas allowance revenue to each eligible emissions-intensive and trade-exposed entity are adopted as described in Appendix A.

3. The Commission's Energy Division shall be responsible for collecting all information and performing calculations necessary to return allowance revenue to emissions –intensive and trade-exposed entities.

4. If the California Air Resources Board substantively revises the sections of its Cap-and-Trade Regulation or its Regulation for the Mandatory Reporting of Greenhouse Gas Emissions pertaining to industry assistance, Energy Division shall prepare for the Commission's consideration a draft resolution recommending any necessary changes to the methodologies adopted in Appendix A to this decision.

5. Energy Division shall conduct a workshop within 60 days of this decision's adoption and issue a draft resolution for the Commission's consideration to develop the details of the attestation process for customers that have direct emissions less than 10,000 $MTCO_2e$ per year and that wish to be eligible as emissions-intensive and trade exposed entities. In this workshop and resolution, staff shall :

- Develop the content of the attestation form that entities must sign to demonstrate to the Commission that they primarily operate in an emissions-intensive and trade exposed entities-eligible industry;
- Identify what additional information entities should provide to the Commission as part of their attestations. For example, such information might include utility billing or meter account information necessary to implement the energy-based allocation methodology.
- Define whether an eligible entity's electricity purchases should be defined based on its utility service account information or on the physical boundary of the entity's facility. Staff shall determine which utility billing and meter information is best suited to ensure that greenhouse gas revenue is returned in an administratively simple manner that also closely corresponds to the point at which Air Resources Board regulates entities under Cap- and-Trade Regulation.
- Establish procedures and specific points of responsibility for verifying that attestations are accurate and that entities

are actually eligible. These procedures should aim to identify and minimize fraudulent attestations.

- Address how an entity responsible for verifying attestations should determine whether an entity primarily engages in activities described by an emissions-intensive and trade exposed entities-eligible NAICS Code.

6. Pacific Gas and Electric Company, Southern California Edison Company, San Diego Gas & Electric Company, Liberty Utilities (CalPeco Electric) LLC, and PacifiCorp shall identify customers that are likely to operate in emissions-intensive and trade –exposed entities (EITE) eligible industries and that are also likely to have direct emissions less than 10,000 $MTCO_2e$ per year. The electric utilities shall notify each customer at least once about its opportunity to attest to the Commission that it is eligible to receive greenhouse gas allowance revenue as an EITE entity.

7. Energy Division shall establish a public yearly schedule by which it will collect all information and data necessary to return allowance revenue to eligible emissions-intensive and trade-exposed customers, including details about the attestation process for entities that have direct emissions less than 10,000 $MTCO_2e$ per year.

8. Energy Division should conduct a workshop and prepare for the Commission's consideration resolution workshop report addressing refinery allocation methodologies for the second and third compliance period, based on Air Resources Board's complexity weighted barrel methodology.

9. Pacific Gas and Electric Company, Southern California Edison Company, San Diego Gas & Electric Company, Liberty Utilities (CalPeco Electric) LLC, and PacifiCorp shall record costs associated with their outreach efforts targeted to entities that have annual direct emissions less than 10,000 $MTCO_2e$ in the administrative cost memorandum accounts authorized in D.12-12-033. These

administrative expenditures should be reviewed in the utilities' greenhouse gas' cost and revenue forecast and reconciliation applications ordered by D.12-12-033 and clarified by D.14-10-033.

10. Pacific Gas and Electric Company, Southern California Edison Company, San Diego Gas & Electric Company, Liberty Utilities (CalPeco Electric) LLC, and PacifiCorp shall record costs associated with collecting, managing, and verifying customer attestations submitted by entities that have annual direct emissions less than 10,000 $MTCO_2e$ in the administrative cost memorandum accounts authorized in D.12-12-033. These administrative expenditures should be reviewed in the utilities' greenhouse gas' cost and revenue forecast and reconciliation applications ordered by D.12-12-033 and clarified by D.14-10-033.

11. Any outstanding motions pertaining to Track 1 of Rulemaking 11-03-012 are denied.

12. Rulemaking 11-03-012 remains open to address issues in other tracks.

This order is effective today.

Dated December 18, 2014, at San Francisco, California.

MICHAEL R. PEEVEY
President
MICHEL PETER FLORIO
CATHERINE J.K. SANDOVAL
CARLA J. PETERMAN
MICHAEL PICKER
Commissioners

Appendix A

Formulas and Rules for Distribution of Greenhouse Gas Allowance Revenue to Emissions-Intensive and Trade-Exposed Customers

1. Product-Based Allocation Equation for an Advance Allocation

Equation 1. Product-Based Allocation Formula for an Advance Allocation

$$A_{b,t} = \left(\sum_{a=1}^{n}(O_{a,t-2} \times B_{EP,a} \times AF_{a,t} \times C_{a,t} \times D_{t-1} \times EF_b)\right) + Trueup_{b,t}$$

Where:

"a" is an eligible industrial activity defined in Table 9-1 of ARB's Cap and Trade regulation.

"b" is an individual industrial facility that operates in industrial activity "a."

"t" is the budget year for which the Commission is allocating revenue.

"$O_{a, t-2}$" is the total production output in year "t-2" associated with a given industrial activity at a given facility subject to the product-based benchmark. ARB's MRR data[1] is the source for product output, which must be discounted by the percentage of the facility's total electricity purchases in year "t-2" that are from publicly-owned utilities.

"$B_{EP,a}$" is the benchmark of electricity intensity of product output for industrial activity "a" in terms of megawatt-hours of electricity purchases per unit output for the applicable sector. The electricity intensity benchmark is calculated by summing the electricity purchases of all California entities in industrial sector "a," and then dividing this amount by sector's total production output for the industrial activity. The exact

[1] Throughout this Appendix, all references to ARB's MRR data refer to the verified MRR data that entities are required to report to ARB in September of each year.

formula used to calculate this benchmark for each industrial activity is discussed in Equation **2**, below.

"$AF_{a,t}$" is the "assistance factor" for budget year "t" assigned to a given industrial activity "a." Assistance factors for each industrial activity are specified in Table 8-1 of ARB's Cap-and-Trade regulation. The assistance factor is the percent of the emissions benchmark that will be provided in an allocation, ranging from 100% to 30%. The specific percentage is tied to ARB's determination of an industrial sector's leakage risk and the year for which the allocation is being sought.

"$C_{a,t}$" is the cap adjustment factor for budget year "t" assigned to each industrial activity "a." The cap adjustment factor represents the decline in the overall GHG cap. The schedule for the cap adjustment factor can be found in Table 9-2 of ARB's Cap-and-Trade Regulation as the Cap-and-Trade Adjustment Factor for All Other Direct Allocation.

"D_{t-1}" is the Dollar Conversion Factor calculated based on the average of CAISO's daily Greenhouse Gas Allocation Index Price for the year "t-1, and is in terms of dollars per $MTCO_2e$."

"EF_b" is the electricity emission factor in $MTCO_2e/MWh$ specific to industrial facility "b" based on the facility's mix of electricity purchases during the 2008 to 2010 historical period and each electricity provider's emission factor as discussed in Section 4.5. The EITE facility-specific emission factor is calculated according to Equation **3** below.

"$Trueup_{b,t}$" is the true-up term defined by Equation **4** below, which adjusts for updated product output "O" and dollar conversion factor "D" data for year "t" once they are available. This value shall only be calculated if the entity was covered under the Cap-and-Trade Program in year "t-2."

1.1. Electricity Intensity Benchmark Equation for a Product-Based Allocation

Equation 2. Electricity Intensity Benchmark Equation for Product-Based Allocation

$$B_{EP,a} = 0.9 \times \frac{\sum_{b=1}^{n}\left[\sum_{IOU=1}^{u} EP_{b,IOU} + \sum_{3rd\ party=1}^{p} EP_{b,3rd\ party}\right]}{\sum_{b=1}^{n} Production_b}$$

Where:

"a" is an eligible industrial activity defined in Table 9-1 of ARB's Cap and Trade regulation.

"b" is an individual industrial facility that operates in industrial activity "a" outlined in Table 9-1 of ARB's Cap and Trade regulation.

0.9 is a benchmark stringency factor chosen to reflect the emissions intensity of highly efficient, low-emitting covered entities for each industrial activity. For sectors in which there is only one covered entity or in which no covered entity is at least as efficient as the benchmark, 0.9 is not used and instead the benchmark is set based on the "best-in-class" value (i.e. the electricity emissions intensity of the most GHG-efficient California facility).

"$EP_{b,\ IOU}$"is the total electricity purchased in MWh by industrial facility "b" from an investor-owned utility. Electricity purchases by a single facility "b" may occur from one or more IOUs, each with its own associated emission factor. Electricity purchases are summed over a historical period, 2008-2010, using ARB's MRR data.

"EF_{IOU}" is the GHG emissions factor specific to each IOU from which the industrial facility "b" purchased electricity. This factor is 0.291 $MTCO_2e$ for PG&E and 0.379 $MTCO_2e$/MWh for all investor-owned utilities.

"$EP_{b,\ 3rd\ party}$" is the total electricity purchased in MWh by industrial facility "b" from a third party electricity provider. Electricity purchases by a single facility "b" may occur from one or more third party providers, each with its own associated emissions factor. Electricity purchases are summed over a historical period, 2008-2010, using ARB's MRR data. Third party electricity providers include all non-investor-owned utility providers: publicly owned utilities (POUs), community choice aggregators (CCAs) direct access providers (DAs) and off-site CHP facilities. This factor is 0.379 $MTCO_2e$/MWh for electricity purchases from all parties that

are not investor-owned utilities, except when electricity is purchased from off-cite CHP facilities a factor of 0.431 $MTCO_2e/MWh$ applies.

"$Production_b$" is the total product output from industrial facility "b," for the industrial activity for which the benchmark is being calculated. Product output is summed over a historical period 2008-2010, using ARB's MRR data, for all industries in California that operate in industrial activity "a."

1.2. Industrial Facility-Specific Weighted Average Emission Factor

Equation 3. Industrial Facility-Specific Weighted Average Emission Factor

$$EF_b = \frac{\sum_{t=2008}^{2010} \sum_{provider=1}^{n} \left(EP_{b,provider,t} \times EF_{provider} \right)}{\sum_{t=2008}^{2010} \sum_{provider=1}^{n} EP_{b,provider,t}}$$

Where:

"b" is an individual industrial facility that operates in industrial activity "a" outlined in Table 9-1 of ARB's Cap and Trade regulation.

"$EP_{b,provider,t}$" is the total electricity purchased in MWh by industrial facility "b" from each electricity provider in year "t," as reported in ARB's MRR data.

"$EF_{provider}$" is the GHG emission factor specific to each electricity provider from which the industrial facility "b" purchase electricity.

1.3. True-Up Term for a Product-Based Allocation

True-ups correct the allocation from two years prior to reflect the actual product output and dollar conversion factor. The first true-up will be conducted in 2016 (to true-up the 2014 allocation).

Equation 4. True-Up Term for a Product-Based Allocation

$$Trueup_{b,t} = \left(\sum_{a=1}^{n} \left(O_{a,t-2} \times B_{EP,a} \times AF_{a,t-2} \times C_{a,t-2} \times D_{t-2} \times EF_b \right) \right) - A_{b,t-2,no\ trueup}$$

Where:

"$A_{b,t\text{-}2,no\ trueup}$" is the amount of allowance revenue that industrial facility "b" received for all industrial activities for budget year "t-2," not including the true-up for that budget year.

The assistance factor, benchmark, cap adjustment factor, output variable, dollar conversion factor and emission factor are all as defined in **Equation 1**, **Equation 2** and **Equation 3** above.

1.4. Illustrative Equation for 2013 Allocation

The allocation to address 2013 costs will occur in 2014 or early 2015 due to the timing of this decision's issuance, and it will occur after ARB has verified data about each facility's 2013 product output. In this case, the 2013 allocation does not need a true up since both 2013 product output and the 2013 dollar conversion factor are known. The following equation will be used.

$$A_{b,2013} = \left(\sum_{a=1}^{n} (O_{a,2013} \times B_{EP,a} \times AF_{a,2013} \times C_{a,2013} \times D_{2013} \times EF_b) \right)$$

1.5. Illustrative Equation for 2014 Allocation

In 2014 the allocation formula will also not include a true-up term. The revenue that facilities receive for the 2014 budget year will be trued-up in the 2016 allocation after verified product output data for 2014 is available from ARB in September 2015. In 2014 the product-based allocation to individual industrial facility "b" will be calculated as follows, except that if the allocation occurs in early 2015 the dollar conversion factor for 2014 will be used:

$$A_{b,2014} = \sum_{a=1}^{n} (O_{a,2013} \times B_{EP,a} \times AF_{a,2014} \times C_{a,2014} \times D_{2013} \times EF_b)$$

1.6. **Illustrative Equation for 2015 Allocation**

A true-up term is also unnecessary in the 2015 allocation, since the 2013 allocation requires no true-up. In 2015 the product-based allocation to individual industrial facility "b" will be calculated as follows:

$$A_{b,2015} = \sum_{a=1}^{n} (O_{a,2013} \times B_{EP,a} \times AF_{a,2015} \times C_{a,2015} \times D_{2014} \times EF_b)$$

The total amount of allowance revenue that a facility will receive in 2015 will be equal to the 2015, 2014, and 2013 allocations.

1.7. **Illustrative Equation for 2016 and Subsequent Years**

The allocation formula for 2016 and all subsequent years will exactly follow the default formulas and will require no modification. In 2016, for example, the allocation will true-up the 2014 allocation and will be calculated as follows:

$$A_{b,2016} = \left(\sum_{a=1}^{n} (O_{a,2014} \times B_{EP,a} \times AF_{a,2016} \times C_{a,2016} \times D_{2015} \times EF_b) \right) + Trueup_{b,2016}$$

$$Trueup_{b,2016} = \left(\sum_{a=1}^{n} \left(O_{a,2014} \times B_{EP,a} \times AF_{a,2014} \times C_{a,2014} \times D_{2014} \times EF_b \right) \right) - A_{b,2014,no\ trueup}$$

2. **Energy-Based Allocation Equation**

Equation **5**, Equation **6** and Equation **7** below illustrate how the energy-based allocation will be conducted in general and for facilities that are classified as having stable emissions data. Opt-in covered entities that have no historical MRR data and entities that have transitional emissions data are addressed as special cases.

Equation 5. Advance Energy-Based Allocation for an Individual Facility

$$A_t = B_{EP,e} \times AF_{a,t} \times C_t \times D_{t-1} + Trueup_t$$

Where:

"t" is the budget year for which revenue is provided to address emissions from electricity purchases and to which the true-up is added to address emissions that occurred during year t-1.

"A_t" is the amount of revenue allocated to the operator of the industrial facility with an energy-based allocation for budget year "t";

"$B_{EP,e}$" is the historical baseline annual arithmetic mean amount of emissions resulting from electricity purchased by the industrial facility from an IOU or other electricity provider, excluding electricity from publicly-owned utilities, measured in $MTCO_2e$, using 2008-2010 emissions as the historical baseline. The formula for this benchmark is defined in Equation **6** below.

"$AF_{a,t}$" is Assistance Factor for budget year "t" assigned to each industrial activity "a" in Table 8-1 of ARB's Cap-and-Trade Regulation. This factor represents the percent of the energy benchmark that will be provided in an allocation, ranging from 30% to 100% in a given budget year. The specific percentage is tied to ARB's determination of an industrial sector's leakage risk and the year for which the allocation is being sought.

"C_t" is the Cap Adjustment Factor for budget year "t." The cap adjustment factor represents the decline in the overall GHG cap. The schedule for the cap adjustment factor can be found in Table 9-2 of ARB's Cap-and-Trade regulation as the Cap Adjustment Factor for All Other Direct Allocation.

"D_{t-1}" is the Dollar Conversion Factor calculated based on the average of CAISO's daily Greenhouse Gas Allowance Index Price for the year "t-1."

"$Trueup_t$" is the true-up term defined by Equation **7** below, which adjusts for the dollar conversion factor "D" for year "t" once available.

2.1. Historical Electricity Emissions Benchmark for an Energy-Based Allocation

The historical electricity emissions benchmark is specific to each facility that qualifies for an energy-based allocation. It is calculated once and is never updated from year to year. The subscript "e" in the benchmark variable distinguishes the benchmark used in the energy-based allocation methodology from that used in the product-based methodology.

For facilities that have direct emissions less than 10,000 $MTCO_2e$ per year and that do not report data under MRR, the Commission will rely on data from the investor owned electric utilities about each facility's bundled (i.e. IOU) and unbundled (i.e. third party) electricity purchases during 2008 through 2010.

Equation 6. Historical Electricity Emissions Benchmark for an Energy-Based Allocation

$$B_{EP,e} = \sum_{IOU=1}^{n} (EP_{IOU} \times EF_{IOU}) + \sum_{3rd\ party=1}^{n} \left(EP_{3rd\ party} \times EF_{3rd\ party}\right)$$

Where:

"EP_{IOU}" is the historical baseline annual arithmetic mean amount of electricity purchased by the industrial facility from an IOU, measured in MWh, using 2008-2010 MRR data as the historical baseline. Electricity purchases may occur from one or more IOUs, each with its own associated emissions factor.

"EF_{IOU}" is the GHG emissions factor specific to the IOU from which the industrial facility purchased electricity. This factor is 0.291 $MTCO_2e$ for PG&E and 0.379 $MTCO_2e$/MWh for all investor-owned utilities.

"$EP_{3rd\ party}$" is the historical baseline annual arithmetic mean amount of electricity purchased by the industrial facility from a third party electricity provider, excluding electricity from publicly-owned utilities, measured in MWh, using 2008-2010 MRR data as the historical baseline. Electricity purchased by a single facility may occur from one or more third party providers, each with its own associated emissions factor.

"$EF_{3rd\ party}$" is the GHG emissions factor specific to the third party electricity provider from which the industrial facility purchased electricity. This factor is 0.379 $MTCO_2e$/MWh for electricity purchases from all parties that are not investor-owned utilities, except when electricity is purchased from off-cite CHP facilities a factor of 0.431 $MTCO_2e$/MWh applies.

2.2. True-Up Term for an Advance Energy-Based Allocation

True-ups correct the previous year's allocation. The first true-up will likely be conducted in 2016 (to true-up the 2015 allocation), since the first revenue allocations in 2015, at which point the 2014 dollar conversion factor will be known.

Equation 7. True-Up Term for an Advance Energy-Based Allocation

$$Trueup_t = \left(B_{EP,e} \times AF_{a,t-1} \times C_{t-1} \times D_{t-1}\right) - A_{t-1,no\ trueup}$$

Where:

"$A_{t\text{-}1,no\ trueup}$"is the amount of allowance revenue that the industrial facility received for budget year "t-1," not including the true-up for that budget year.

The benchmark, assistance factor, cap adjustment factor and dollar conversion factor variables are as defined in **Equation 5**.

2.3. Illustrative Equation for 2015 Allocation and Subsequent Years

Like the 2013 and 2014 product-based allocations, the energy-based allocations conducted for 2013 and 2014 will not include a true-up term because the actual dollar conversion factor will be known. However, the 2015 allocation will need to be trued up to update the dollar conversion factor, and this true up will occur in the 2016 allocation in the following manner:

$$A_{2016} = B_{EP,e} \times AF_{a,2016} \times C_{2016} \times D_{2015} + \left(\left(B_{EP,e} \times AF_{a,2015} \times C_{2015} \times D_{2015} \right) - A_{2015,no\ trueup} \right)$$

2.4. Opt-In Covered Entities without Historical Baseline Emissions

When ARB allocates allowances pursuant to Section 95891(c)(3)(A) of its Cap-and-Trade Regulation, which only applies to opt-in covered entities that do not have historical baseline emissions data, the Commission will rely on information ARB provides about each facility's estimated electricity purchases. If ARB does not have these estimates, the facilities will not receive allowance revenue pursuant to the energy-based allocation methodology until ARB has verified MRR data from these facilities.

If ARB provides information about a facility's estimated electricity purchases, the Commission will calculate the facility's allowance revenue according to Equation **5**, Equation **6** and Equation **7**, except that the variable $B_{EP,e}$ in each of these equations shall be replaced with the following estimated emission benchmark variable $B_{EP,e,est}$, defined by the equation below:

Equation 8. Estimated Benchmark of Electricity Emissions

$$B_{EP,e,est} = \sum_{IOU=1}^{n} \left(EP_{IOU,est} \times EF_{IOU}\right) + \sum_{3rd\ party=1}^{n} \left(EP_{3rd\ party,est} \times EF_{3rd\ party}\right)$$

Where:

"$EP_{IOU,\ est}$" is the estimated annual amount of electricity purchased by the industrial facility from an IOU, measured in MWh, as determined by ARB. Electricity purchases may occur from one or more IOUs, each with its own associated emissions factor.

"EF_{IOU}" is the GHG emissions factor specific to the IOU from which the industrial facility purchased electricity. This factor is 0.291 $MTCO_2e$ for PG&E and 0.379 $MTCO_2e$/MWh for all investor-owned utilities.

"$EP_{3rd\ party,\ est}$" is the estimated annual amount of electricity purchased by the industrial facility from a third party electricity provider, excluding electricity purchased from publicly-owned utilities, measured in MWh, as determined by ARB. Electricity purchased by a single facility may occur from one or more third party providers, each with its own associated emissions factor.

"$EF_{3rd\ party}$" is the GHG emissions factor specific to the third party electricity provider from which the industrial facility purchased electricity. This factor is 0.379 $MTCO_2e$/MWh for electricity purchases from all parties that are not investor-owned utilities, except when electricity is purchased from off-cite CHP facilities a factor of 0.431 $MTCO_2e$/MWh applies.

This equation only applies until ARB has verified MRR data for these facilities.

2.5. **New Entrants with Transitional Emissions Data**

The stability formula in Section 95891(c)(3)(D) of ARB's Cap-and-Trade Regulation applies to covered entities or opt-in covered entities, and it identifies

whether an entity's emissions should be classified as stable or transitional. For any entity eligible for an energy-based allocation that ARB classifies as stable, Equation **5**, Equation **6** and Equation **7** will apply, unmodified. However, for entities that ARB classifies as having transitional data, the following formulas will apply, which mirror those in Section 95891(c)(3)(B) of ARB's Cap-and-Trade Regulation. These equations rely on electricity purchases from year "t-2," rather than on the historical baseline annual arithmetic mean amount of electricity purchased. The stability test and Equation **9** also apply to facilities that have annual direct emissions less than 10,000 $MTCO_2e$ and that do not report to ARB under MRR, though in this case the Commission will rely on data from the investor-owned electricity utilities rather than MRR data.

Equation 9. Advance Energy-Based Allocation for an Individual Facility with Transitional Emissions Data

$$A_t = B_{EP,e,t-2} \times AF_{a,t} \times C_t \times D_{t-1} + Trueup_t$$

Where:

"t" is the budget year for which revenue is provided to address emissions from electricity purchases and to which the true-up is added to address emissions that occurred during year "t-2."

"A_t" is the amount of revenue allocated to the operator of the industrial facility with transitional emissions data for budget year "t."

"$B_{EP,e,t-2}$" is the annual amount of emissions resulting from electricity purchases by the industrial facility from an IOU or other electricity provider, excluding publicly-owned utilities, measured in $MTCO_2e$, using "t-2" MRR data. The formula for this benchmark is defined in Equation **10** below.

"$Trueup_t$" is the true-up term defined by Equation **11** below, which adjusts for actual electricity purchases from year "t-2" and the dollar conversion factor "D" for year "t" once they are available. The true-up term will only

be calculated if the entity was covered under the Cap-and-Trade Program in year "t-2."

The assistance factor, cap adjustment factor and dollar conversion factor are exactly as defined in Equation **5**.

2.5.1. Electricity Emissions Benchmark for an Energy-Based Allocation to Facilities with Transitional Emissions Data

The following benchmark variable will be used for facilities that have transitional emissions data:

Equation 10. Benchmark of Electricity Emissions for a Facility with Transitional Emissions Data

$$B_{EP,e,t-2} = \sum_{IOU=1}^{n} \left(EP_{IOU,t-2} \times EF_{IOU}\right) + \sum_{3rd\ party=1}^{n} \left(EP_{3rd\ party,t-2} \times EF_{3rd\ party}\right)$$

Where:

"$EP_{IOU,\ t\text{-}2}$" is the annual amount of electricity purchased by the industrial facility from an IOU in year "t-2," measured in MWh, using ARB MRR data. Electricity purchases may occur from one or more IOUs, each with its own associated emissions factor.

"EF_{IOU}" is the GHG emissions factor specific to the IOU from which the industrial facility purchased electricity. This factor is 0.291 $MTCO_2e$ for PG&E and 0.379 $MTCO_2e/MWh$ for all investor-owned utilities.

"$EP_{3rd\ party,\ t\text{-}2}$" is the annual amount of electricity purchased by the industrial facility from a third party electricity provider in year "t-2," measured in MWh, using ARB MRR data. Electricity purchased by a single facility may occur from one or more third party providers, excluding publicly-owned utilities, each with its own associated emissions factor.

"$EF_{3rd\ party}$" is the GHG emissions factor specific to the third party electricity provider from which the industrial facility purchased electricity.

This factor is 0.379 $MTCO_2e/MWh$ for electricity purchases from all parties that are not investor-owned utilities, except when electricity is purchased from off-cite CHP facilities a factor of 0.431 $MTCO_2e/MWh$ applies.

2.5.2. True-Up Term for an Advance Energy-Based Allocation to Facilities with Transitional Emissions Data

The following true-up term applies to facilities that have transitional emissions data. Like the true-up for the product-based allocation, this true-up term will correct the allocation from two years prior, once actual MRR data is available.

Equation 11. True-Up Term for Advanced Energy-Based Allocation for a Facility with Transitional Emissions Data

$$Trueup_t = \left(B_{EP,e,t-2} \times AF_{a,t-2} \times C_{t-2} \times D_{t-2}\right) - A_{t-2,no\ trueup}$$

The assistance factor, cap adjustment factor and dollar conversion factor variables are as defined in Equation **5**. The benchmark variable is as calculated in Equation **10**.

The 2015 allocation is the first that will certainly require a true-up, and this true-up will occur in 2016.

3. Refinery Allocation Equation for First Compliance Period

The following series of equations will be used to allocate allowance revenue to individual refineries during the first Cap-and-Trade compliance period. First, allowance revenue is allocated to the refinery sector as a whole, based on a product-based, "simple barrel," benchmark. This allows the total amount of allowance revenue allocated to the refinery sector to increase or decrease automatically in response to future production levels of refinery

products. Second, allowance revenue is allocated to individual refineries based on the complexity of the refinery. For simple refineries (i.e. those without a Solomon Energy Intensity Index (EII) value) a simple barrel product benchmark applies; and for complex refineries (i.e. those with an EII value), a more complex formula applies that accounts for each refinery's historical emissions and its relative efficiency compared to other refineries.

3.1. **Refinery Sector Allocation**

Equation 12. Refinery Sector Allocation

$$SA_{EP,t} = AF_t \times B_{EP} \times C_t \times O_{t-2}$$

Where:

"$SA_{EP,t}$" is the annual allocation to the refining sector for emissions from purchased electricity for budget year t. This variable is in terms of allowances ($MTCO_2e$). (Allocations to individual refineries will be converted to dollars.)

"AF_t" is the assistance factor for budget year t assigned to petroleum refining sector (NAICS Code 324110) as specified in Table 8-1 of ARB's Cap-and-Trade regulation.

"B_{EP}" is the emissions benchmark for electricity purchased for primary products produced by the refining sector. It is determined by the following equation, which is identical to the product-based benchmark for electricity purchases defined in Equation **2**:

$$B_{EP} = 0.9 \times \frac{\sum_{r=1}^{n}\left[\sum_{IOU=1}^{u}\left(EP_{r,IOU} \times EF_{IOU}\right) + \sum_{3rd\ party=1}^{p}\left(EP_{r,3rd\ party} \times EF_{3rd\ party}\right)\right]}{\sum_{r=1}^{n} Production_r}$$

Where:

0.9 is the benchmark stringency chosen to reflect the emissions intensity of highly efficient, low-emitting covered entities within the sector.

"$EP_{r,IOU}$" is the total electricity purchased in MWh by industrial facility "r" within the refinery sector from an investor-owned utility. Electricity purchases by a single facility, "r," may occur from one or more utility. Electricity purchases are summed over a historical period, 2008-2010, using ARB's MRR data.

"EF_{IOU}" is the GHG emissions factor specific to the investor-owned utility from which the industrial facility "r" purchased electricity. This factor is 0.291 $MTCO_2e$ for PG&E and 0.379 $MTCO_2e$/MWh for all investor-owned utilities.

"$EP_{r,\ 3rd\ party}$" is the total electricity purchased in MWh by industrial facility "r" within the refinery sector from a third party electricity provider. Electricity purchases by a single facility "r" may occur from one or more third party providers. Electricity purchases are summed over a historical period, 2008-2010, using ARB's MRR data.

"$EF_{3rd\ party}$" is the GHG emissions factor specific to the third party electricity provider. This factor is 0.379 $MTCO_2e$/MWh for electricity purchases from all parties that are not investor-owned utilities, except when electricity is purchased from off-cite CHP facilities a factor of 0.431 $MTCO_2e$/MWh applies.

"$Production_r$" is the total output of primary refinery products produced by industrial facility "r," in the refining sector. Product output is summed over a historical period 2008-2010, using ARB's MRR data discounted by the percentage of the refinery sector's total electricity purchases in year "t-2" that are from publicly-owned utilities.

"C_t" is the cap adjustment factor for budget year "t." The schedule for the cap adjustment factor can be found in Table 9-2 of ARB's Cap-and-Trade regulation as the Cap Adjustment Factor for All Other Direct Allocation.

"O_{t-2}" is the output of primary refinery products, in barrels, from the refining sector in year t-2.

Like the product and energy-based allocations, the refinery allocation will be granted in advance of costs being incurred.

3.2. **Allocation to Facilities Without EII Values (Simple Refineries)**

Refineries without an EII value are granted allowance revenue based on the following simple barrel benchmark approach, which is equivalent to the product-based allocation methodology, limited to be no greater than a refinery's historical emissions.

Equation 13. Revenue Allocation to Individual Refineries without EII Values (Simple Refineries)

$$AR_{X,t} = A_{X,t} \times D_t$$

Where:

"$AR_{X,t}$" is the allocation of revenue in dollars to an individual refinery "X" for budget year "t."

"$A_{X,t}$" is the allocation of allowances to an individual refinery "X" for budget year "t" as calculated by either Equation **14** or Equation **15** below.

"D_t" is the dollar conversion factor calculated based on the average of CAISO's daily Greenhouse Gas Allowance Index Price for the year "t." It is possible to use year "t" rather than year "t-1" since these refinery equations will only be used during the first compliance period, and the revenue allocations for 2013 and 2014 will not be conducted until early 2015, at which point the dollar conversion factors for 2013 and 2014 will be known.

Equation 14. If Simple Barrel Method Is Less than Historical Emissions

$$If: O_{X,t-2} \times B_{EP} \times AF_t \times C_t \leq BE_{EP,X} \times AF_t \times C_t$$

$$Then: A_{X,t} = O_{X,t-2} \times B_{EP} \times AF_t \times C_t$$

(A product-based allocation)

Equation 15. If Simple Barrel Method Exceeds Historical Emissions

$$If: O_{X,t-2} \times B_{EP} \times AF_t \times C_t \geq BE_{EP,X} \times AF_t \times C_t$$

$$Then: A_{X,t} = BE_{EP,X} \times AF_t \times C_t$$

(An emissions-based allocation)

Where:

"$O_{X,t-2}$" is the output of primary refinery products, in barrels, from refinery "X" in year t-2, discounted by the percentage of the refinery's total electricity purchases in year "t-2" that are from publicly-owned utilities. (However, verified 2013 product output data is presently available, so primary refinery product data from year "t" will be used for the 2013 allocation; and product data from year "t-1" will be used for the 2014 allocation.)

"B_{EP}" is the emissions benchmark for electricity purchased for primary products produced by the refining sector. This benchmark applies to the refinery sector as a whole, and is not specific to an individual refinery. It is defined in
Equation **12** above.

"AF_t" is the assistance factor for budget year "t" assigned to petroleum refining sector (NAICS Code 324110) as specified in Table 8-1 of ARB's Cap-and-Trade regulation.

"C_t" is the cap adjustment factor for budget year "t." The schedule for the cap adjustment factor can be found in Table 9-2 of ARB's Cap-and-Trade regulation as the Cap Adjustment Factor for All Other Direct Allocation.

"$BE_{EP,X}$"is the baseline average annual greenhouse gas emissions for purchased electricity for refinery "X" over a historical period, 2008-2010, or

a period determined by the ARB Executive Officer for the refinery's direct allowance allocation. This is a facility specific benchmark .

3.2.1. **True-Up for Refineries without EII Values**

The revenue allocation for 2014 will be trued-up to account for actual product output in the 2016 allocation. This true-up will occur according to the following equations, which will be added to the 2016 allocation to be conducted according to a complexity weighted barrel methodology.

Equation 16. True-Up if Entity Received Initial Revenue via a Product-Based Allocation

$$TrueUp_{X,t} = \left(O_{X,t-2} \times B_{EP} \times AF_{t-2} \times C_{t-2}\right) - AR_{X,t-2}$$

Where:

"$TrueUp_{X,t}$"is the amount of true-up allowance revenue allocated to account for changes in product output and the dollar conversion factor not properly accounted for in prior allocations for refinery "X."

"$AR_{X,t-2}$" is the amount of allowance revenue that refinery "X" without an EII value received for budget year "t-2."

Equation 17. True-Up if Entity Received Initial Revenue via an Emissions-Based Allocation

$$If: AE_{EP,X,t-2} < BE_{EP,X} \times 0.8$$

$$Then: TrueUp_{X,t} = \left(AE_{EP,X,t-2} \times AF_{t-2} \times C_{t-2}\right) - AR_{X,t-2}$$

Where:

"$AE_{EP,X,t-2}$" is the emissions from electricity purchased by refinery "X" without an EII Value for budget year "t-2," using the following equation:

$$AE_{EP,X,t-2} = \sum_{IOU=1}^{u} \left(EP_{IOU,t-2} \times EF_{IOU}\right) + \sum_{3rd\ party=1}^{p} \left(EP_{3rd\ party,t-2} \times EF_{3rd\ party}\right)$$

Where:

"$EP_{IOU,t-2}$" is the annual amount of electricity purchased by refinery "X" from an IOU in year "t-2," measured in MWh, using ARB MRR data. Electricity purchases may occur from one or more IOUs, each with its own associated emissions factor.

"EF_{IOU}" is the GHG emissions factor specific to the IOU from which the industrial facility purchased electricity. This factor is 0.291 $MTCO_2e$ for PG&E and 0.379 $MTCO_2e$/MWh for all investor-owned utilities.

"$EP_{3rd\ party,t-2}$" is the annual amount of electricity purchased by refinery "X" from a third party electricity provider in year "t-2," measured in MWh, using ARB MRR data. Electricity purchased by a single facility may occur from one or more third party providers, each with its own associated emissions factor.

"$EF_{3rd\ party}$" is the GHG emissions factor specific to the third party electricity provider from which the industrial facility purchased electricity. This factor is 0.379 $MTCO_2e$/MWh for electricity purchases from all parties that are not investor-owned utilities, except when electricity is purchased from off-cite CHP facilities a factor of 0.431 $MTCO_2e$/MWh applies.

3.3. **Allocation to Facilities with EII Values (Complex Refineries)**

The methodology below exactly mirrors ARB's methodology with the same two changes employed throughout this decision: it ensures that the benchmark reflects emissions from electricity purchases, rather than direct emissions, and it converts allowances into dollars.

Equation 18. Revenue Allocation to Individual Refineries with EII Values (Complex Refineries)

$$AR_{Y,t} = BE_{EP,Y} \times DF_{Y,t} \times F_t \times D_t$$

Where:

"$AR_{Y,t}$" is the allocation of revenue in dollars to an individual refinery "Y" that has an EII value for budget year "t".

"$BE_{EP,Y}$" is the baseline average annual greenhouse gas emissions from purchased electricity for refinery "Y" over a historical period, 2008-2010, or a period determined by the ARB Executive Officer for the refinery's direct allowance allocation. This is a facility specific benchmark.

"$DF_{Y,t}$" is a distribution factor calculated as:

$$DF_{Y,t} = \left((Avg_{EP}/EII_Y) + Adj_{EP,t}\right)/\left(1 + Adj_{EP,t}\right)$$

Where:
"Avg_{EP}" is the weighted average EII for all facilities with EII values, and is calculated as:

$$Avg_{EP} = \frac{\sum_{Y=1}^{n} BE_{EP,Y}}{\sum_{Y}^{n}\left(BE_{EP,Y}/EII_Y\right)}$$

"EII_Y" is the Solomon Energy Intensity Index (EII) for facility "Y" for 2008, 2009 or 2010 as determined to be representative by the ARB's Executive Officer. For the purposes of this calculation, EII values shall be rounded to one digit after the decimal. EII values are to remain confidential to ARB.

"$Adj_{EP,t}$" is an adjustment factor designed to provide the covered entity with the best EII the most allowances relative to its baseline level:

$$Adj_{EP,t} = \left((\mathrm{Avg_{EP}}/\mathrm{EII_{Best}}) \times \mathrm{F_t} - 1\right)/(1 - \mathrm{F_t})$$

"EII_{Best}" is the EII of the most efficient covered entity (lowest EII in the sector).

"F_t" is a fraction that adjusts the complex refinery allocation to account for the remaining refinery sector allowances after allocations are made for simple refineries, and is calculated as:

$$F_t = \frac{SA_{EP,t} - \sum_{X=1}^{n} A_{X,t}}{\sum_{Y=1}^{n} BE_{EP,Y}}$$

Where:
"$SA_{EP,t}$" is the annual allocation to the refining sector for emissions from purchased electricity for budget year t, as defined in **Equation 12**. This variable is in terms of allowances ($MTCO_2e$).

"$A_{X,t}$" is the allocation in terms of allowances ($MTCO_2e$) to simple refinery "X" without an EII value for year "t."

"D_t" is the dollar conversion factor calculated based on the average of CAISO's daily Greenhouse Gas Allowance Index Price for the year "t." (The year "t" can be used since the allocations for 2013 and 2014 will not occur until early 2015, at which point the dollar conversion factor for both years will be known.)

The calculations necessary to execute **Equation 18** require the use of confidential and proprietary Solomon EII values that ARB cannot share with Energy Division. To implement this calculation in a manner that respects these confidentiality requirements, Energy Division will compute the refinery sector allocation, $SA_{EP,t}$, and the sum of the revenue allocation to simple refineries without EII values, $\Sigma A_{X,t}$, and it will then communicate these results to ARB, which will allow ARB to calculate the fixed fraction, F_t, and the distribution factor specific to each complex refinery, $DF_{Y,t}$, without communicating EII data to Energy Division.

3.3.1. **True-Up Process for Refineries with EII Values**

The following true-up formulas parallel ARB's true-up for complex refineries. If actual 2014 emissions from electricity purchases are less than the amount of revenue provided for those years, a true-up will be conducted after September 2015 (after verified MRR data is available about 2014 electricity purchase is available) and the excess revenue that the refinery received will be subtracted from the revenue allocation that occurs in 2016. This true-up equation differs from the equation included in the Staff Proposal because it is no longer necessary to true-up the 2013 allocation: as of this date, verified 2013 MRR data are available.

Equation 19. Complex Refinery True-Up If Actual Electricity Emissions Are Less than Revenue Provided

$$If: \left(AE_{EP,Y,2014} \times D_{2014}\right) < AR_{Y,2014}$$

$$Then: TrueUp_{Y,Debit,2016} = 0.8 \times \left(\left(AE_{EP,Y,2014} \times D_{2014}\right) - AR_{Y,2014}\right)$$

Where:

"$TrueUp_{Y,Debit,2016}$" is the revenue in dollars that will be deducted from the refinery "Y's" next revenue allocation in 2016 to account for changes in production or allocation not properly accounted for in prior allocations.

"$AR_{Y,t}$" is the allocation of revenue in dollars that individual refinery "Y" received for GHG emissions from electricity purchases experienced in year "t".

"$AE_{EP,Y,t}$" is refinery "Y's" actual GHG emissions for purchased electricity in year "t." Since actual GHG emission from electricity purchases are difficult to exactly measure in any given year, these emissions will be calculated based on the same fixed emissions factors approved in this decision. Actual emissions would therefore be estimated according to the following formula:

$$AE_{EP,Y,t} = \sum_{IOU=1}^{n} \left(EP_{IOU,t} \times EF_{IOU}\right) + \sum_{3rd\ party=1}^{n} \left(EP_{3rd\ party,t} \times EF_{3rd\ party}\right)$$

Where:

"$EP_{IOU,t}$" is the total electricity purchased in MWh by facility "Y" within the refinery sector from an investor-owned utility during year "t." Electricity purchases by a single facility, "Y", may occur from one or more IOU, each with its own associated emission factor.

"EF_{IOU}" is the GHG emissions factor specific to the investor-owned utility from which the industrial facility "Y" purchased electricity. This factor is 0.291 $MTCO_2e$ for PG&E and 0.379 $MTCO_2e/MWh$ for all investor-owned utilities.

"$EP_{3rd\ party,t}$" is the total electricity purchased in MWh by facility "Y" within the refinery sector from a third party electricity provider during year "t." Electricity purchases by a single facility "Y" may occur from one or more third party providers, each with its own associated emissions factor.

"$EF_{3rd\ party}$" is the GHG emissions factor specific to the third party electricity provider. This factor is 0.379 $MTCO_2e/MWh$ for electricity purchases from all parties that are not investor-owned utilities, except when electricity is purchased from off-cite CHP facilities a factor of 0.431 $MTCO_2e/MWh$ applies.

"D_t" is the dollar conversion factor applicable to budget year "t."

If actual 2014 emissions from electricity purchases are greater than the amount of revenue provided, a true-up allocation will be conducted after September 2015, and the facility will be credited with additional allowance revenue in the 2016 revenue allocation. This true-up equation differs from the

equation included in the Staff Proposal because it is no longer necessary to true-up the 2013 allocation: as of this date, verified 2013 MRR data are available.

Equation 20. Complex Refinery True-Up If Actual Emissions Are Greater than Revenue Provided

$$If: BE_{EP,Y} < AE_{EP,Y,2014}$$

$$Then: TrueUp_{Y,Credit,2016} =$$

$$0.8 \times \left(\left(AE_{EP,Y,2014} \times DF_{Y,2014} \times AF_{2014} \times F_{2014} \times D_{2014} \right) - AR_{Y,2014} \right)$$

Where:

"$TrueUp_{Y,Credit,2016}$" is the revenue in dollars that will be added to refinery "Y's" next revenue allocation in 2016 to account for changes in production or allocation not properly accounted for in prior allocations.

"$BE_{EP,Y}$" is the average annual greenhouse gas emissions from purchased electricity for refinery "Y" over a historical period, 2008-2010. This value is expressed in **Equation 18**, and is calculated once at the outset of the program.

"$AE_{EP,Y,t}$" is refinery "Y's" actual GHG emissions for purchased electricity in year "t." These emissions will be calculated based on the same fixed emissions factors used throughout this decision. Actual emissions would therefore be estimated according to the formula expressed in **Equation 19** above.

"$DF_{Y,t}$" is the distribution factor calculated as in **Equation 18**.

"AF_t" is the refinery assistance factor for year "t."

"F_t" is a fraction as calculated in **Equation 18**.

"D_t" is the dollar conversion factor used to convert metric tons of emissions into dollars.

"$AR_{Y,t}$" is the allocation of revenue in dollars that individual refinery "Y" received for GHG emissions from electricity purchases experienced in year "t".

(END OF ATTACHMENT)