California Air Resources Board

Frequently Asked Questions Regarding the GHG Mandatory Reporting and Verification Program

Combined Reporting and Verification FAQs for 2010 Emissions Reported in 2011 [Applicable for 2010 emissions reporting only]

ARB's mandatory greenhouse gas (GHG) reporting regulation, which appears at sections 95100-95133 of title 17, California Code of Regulations, is a set of rules that establishes who must report GHG emissions to ARB and sets forth the requirements for measuring, calculating, reporting and verifying those emissions. In this document ARB staff has updated FAQs with questions received during both the reporting and verification of 2009 emissions data reports in 2010. If you have GHG reporting questions, please contact ARB staff at ghgreport@arb.ca.gov. If you have GHG verification questions, please contact ARB staff at ghgverify@arb.ca.gov.

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Unlike the regulation itself, this guidance does not have the force of law. It is not intended to and cannot establish new mandatory requirements beyond those that are already in the regulation, and it does not supplant, replace or amend any of the legal requirements of the regulation. Conversely, this guidance's omission or truncation of regulatory requirements does not relieve operators of their legal obligation to fully comply with all requirements of the regulation. Archives of previous FAQs may be found here: http://www.arb.ca.gov/cc/reporting/ghg-rep/ghg_rep_faqs.pdf and http://www.arb.ca.gov/cc/reporting/ghg-ver/faq.pdf

This document is available at: http://www.arb.ca.gov/cc/reporting/ghg-rep/updated_faq.pdf

General Reporting Questions

Deadlines and Reporting Responsibilities

1. Q: How do I determine if I am subject to ARB's GHG emissions reporting regulation? **How do I report** my 2010 emissions in 2011?

   A: For most industrial sectors, the mandatory reporting regulation (http://www.arb.ca.gov/regact/2007/ghg2007/frofinoal.pdf) specifies a reporting threshold of 25,000 metric tonnes of carbon dioxide (CO_2). Table 2.4c of ARB's *Instructional Guidance* document (http://www.arb.ca.gov/cc/reporting/ghg-rep/ghg-rep-guid/00_06_GenProvs.pdf) provides equivalent reporting thresholds by fuel type. For example, if your facility uses more than 471,520 MMBtu (460,000,000 scf) of natural gas, or 12,000 short tons of coal, your facility is likely to be subject to the reporting regulation. Similarly, if your facility has the capacity to generate more than 1 MW of electricity and emits at least 2,500 metric tonnes of CO_2 from generating activities, you are required to report. Electricity retail providers and marketers are also required to report.

   If you believe you are subject to the reporting regulation, please contact ARB staff (ghgreport@arb.ca.gov) to receive information about how to report your emissions and to have an account created within the GHG Reporting Tool (http://www.arb.ca.gov/cc/reporting/ghg-rep/ghg-tool.htm).

2. Q: **When do I have to report** year 2010 emissions?

   A: By April 1 or June 1, 2011, depending on your industry sector. Reporting deadlines are described on page 26 of the regulation http://www.arb.ca.gov/regact/2007/ghg2007/frofinoal.pdf.

3. Q: For facilities starting **operation in 2010**, when are reporting and verification required?

   A: GHG emissions reporting and verification are required for the first full year of operation (§95103(d)). For facilities that did not commence operations by January 2010, the first reports will be due in 2012 pursuant to the requirements in the revised Mandatory GHG Reporting Regulation (see http://www.arb.ca.gov/regact/2010/ghg2010/ghg2010.htm), upon OAL (Office of Admin. Law) approval of these requirements.

4. Q: If after reporting my 2009 emissions in 2010 I discover that I **reported something wrong**, either the magnitude of the emissions or the way I set up my facility, what should I do?

   A: Contact ARB staff (and your verifier if applicable) to determine if changes may be made to the emissions report.

5. Q: My facility ceased operation mid-year. Am I required to report emissions from that calendar year? If the company was **sold mid-year**, who is responsible for reporting?

   A: Any facility that meets (or has met in the last 3 years) the applicability requirements is required to report, whether or not the facility or entity is operational when the reports are due. For those facilities or entities subject to reporting, responsibility for reporting annual emissions that occurred rests with the operator of the facility (both the former and the current operator). Ideally the current operator would receive all of the relevant information from the previous operator and report all emissions that occurred during that calendar year. Even if the plant is shut down, if reporting applicability is triggered (or was previously triggered), this does not relieve the operator(s) from reporting facility emissions that occurred during that report year. Please contact ARB staff to clarify facility-specific compliance requirements.

6. Q: For 2010, our facility emissions were **below the reporting threshold** due to business conditions. What do I need to do?

   A: If previously subject to reporting, §95103(e) requires operators to continue reporting their emissions for three years after reducing emissions below the applicability threshold. If emissions are zero due to a plant shutdown, zero emissions should be reported for one year.

Reporting Thresholds and Boundaries

7. Q: Are **emergency fire pumps** required to be included in the emissions report? If so, do the fuel flows to these units need to be measured by a meter demonstrated to be accurate to within +/-5 percent?

   A: Yes, fire pumps must be included. Fire pumps are not exempt from reporting if the facility is subject to reporting, even when permitted as emergency equipment by a local air quality management district. The exemption only applies to portable equipment and emergency generators, pursuant to section 95101(c)(3). Evaluate whether these emissions can be reported as *de minimis*, which means the fuel does not have to be measured within +/-5 percent accuracy.

8. Q: Does fuel used for **non-production** activities (like gas used for a water heater for employee showers) need to be reported?

   A: In most cases all stationary combustion sources at the facility should be reported. An exception is the case of a facility reporting electricity generation or cogeneration emissions only, whose primary business is in another sector and whose total emissions are less than 25,000 MT CO_2. For example, a university whose total emissions are under 25,000 MT may report emissions from its 1 MW cogeneration unit only.

9. Q: What are the reporting requirements for **hydroelectric plant operators**?

A: If you are the operator of a hydroelectric facility and are not a retail provider nor an importer/exporter of power, you are not required to report. You may want to examine the list of generating facilities posted on our website to ensure that your facility is listed and appropriately assigned an ARB identification number. This number will be used by power entities to report specified purchases from your facility.

If you are a retail provider and operate a hydroelectric facility, you are required to report certain non-emissions data for your facility. Please review Table 8.8 of ARB's *Instructional Guidance*.

10. Q: I operate a cogeneration system, but I **do not own the property** or the cogeneration equipment. I am surrounded by a refinery that is already subject to the reporting regulation. Who reports emissions from the cogeneration?

A: The entity with operational control is required to report, regardless of ownership. If two or more parties share operation of the cogeneration, the entity with the local air district permit is responsible for reporting.

11. Q: How do I report emissions from a company with a **large campus** with 40 buildings, including distinct groups of buildings spread out over a number of roads in the general area? There is no **physical boundary** as such around the whole campus. The campus as a whole emits >25,000 MT CO_2 from on-site combustion (primarily natural gas) annually but no individual building or boiler emits this amount. However, there is a central group of buildings that do emit over 25,000 MT CO_2.

A: The company should report as a single facility when emitting activities are located on contiguous or adjacent properties, or separated only by a public right-of-way. Portions of the campus that are geographically independent (i.e., separated by more than just a public right-of-way) are not included in the report.

12. Q: I have an electricity generation unit that uses **steam provided by natural gas fired boilers** to generate electricity. Will the electricity generation system be included in the reporting?

A: If natural gas is burned to generate steam, and then the steam is used to generate power, the unit is subject to reporting if the generating capacity is 1 MW or more and its CO_2 emissions are at least 2,500 MT for the report year. In this scenario, the boilers are included in the definition of "generating unit." Section 95102 states that 'generating unit' means any combination of physically connected generator(s), reactor(s), boiler(s), combustion turbine(s), or other prime mover(s) operated together to produce electric power.

13. Q: Does an electricity generation facility that combusts **biogas** count **pass-through CO_2** emissions when determining if it meets the 2,500 MT CO_2 threshold?

A: No, pass-through CO_2 associated with combusting biogas is not included when determining whether facilities meet reporting thresholds. Electricity generating and cogeneration facility CO_2 emissions from combusting fossil fuels and biomass-derived fuels (excluding pass-through CO_2 associated with combusting biogas) are included in the threshold determination, along with process emissions, and fugitive CO_2 emissions from geothermal facilities.

However, when *reporting* the emissions from combusting biogas, pass-through CO_2 is included and is in the emission factor provided in the regulation. Both emissions from combusting biogas as well as the pass-through CO_2 are reported as biomass-derived CO_2 in order to distinguish these emissions from those associated with fossil fuels. For distribution of emissions for a cogeneration system, only CO_2 emissions from combusting fossil fuels are distributed between thermal energy and electricity generation.

14. Q: Is all **portable equipment**, such as flood pumps, exempt from reporting?

    A: Yes, all portable equipment is exempt.

15. Q: Are emissions from **fuel cells** required to be reported?

    A: No, the regulation does not currently require fuel cells to be reported, but voluntary reporting of fuel cell information is encouraged. However, reporters should be aware of any mandatory reporting requirements for fuel cell units in the revised Mandatory GHG Reporting Regulation effective in January 2012 (see http://www.arb.ca.gov/regact/2010/ghg2010/ghg2010.htm).

16. Q: If a facility such as a manufacturer or a wastewater treatment plant that emits less than 25,000 MT CO_2 installs a **cogeneration** system that emits >2,500 MT CO_2, is the **entire facility subject to reporting**, or is just the cogeneration subject to reporting?

    A: If the facility total emissions are under 25,000 MT CO_2, the operator would only report emissions for the cogeneration unit. If the facility plus the cogeneration emissions exceed 25,000 MT CO_2, reporting of overall facility emissions is required, including the cogeneration system.

17. Q: Are **emergency generators** at an electricity generation facility exempt from reporting?

    A: Yes, emergency generators that help restore station service power in the event of loss of grid electricity, and which are permitted as such by a local air district, are exempt from GHG emissions reporting. See §95101(c)(3) of the regulation.

18. Q: Are "emergency fire pumps" included in the definition for **emergency generators?** They do not supply primary power to the facility in an emergency. However, they are permitted by the local air district as emergency equipment.

    A: *Please see answer to question 7.*

19. Q: We operate two **standby boilers** that operate less than 30 days per year. Are they considered **standby equipment** and exempt from reporting? They are not permitted as "standby" by the local air district, but cannot operate at the same time as a permitted cogeneration unit.

    A: These boilers would not be exempt. All combustion sources specified in the regulation must be included in your emissions report unless they are identified by the local air district as emergency or backup generators.

GHG Reporting Tool

20. Q: Does the **principal contact** have to be the person who will **certify** the emissions?

    A: The tool does not include a designation for a "principal contact" but instead allows designation of "facility managers." Two Primary Facility (or Entity) Managers may be designated within the tool for a facility, and an unlimited number of Alternate Facility Managers can be added to a facility by a manager. The first person to register a new facility is automatically assigned the role of Primary Facility Manager. Any of the "managers" has the ability to certify the emissions data. Facility managers may oversee the GHG emissions reporting, or may be actually inputting data themselves, based on the facility organizational structure. Managers may also use the tool to add "facility reporters" who have access to create and edit facility data within the Reporting Tool, but who do not have the capability to certify the data as complete and accurate.

21. Q: Can **facility managers** be changed in the future? For example, because the first person to register is automatically assigned as the Primary Facility Manager, can that be changed later on?

    A: Yes; however we recommend that someone employed by the facility register the facility within the Reporting Tool (versus having a consultant do it). Within the tool, a user with facility manager privileges can assign different facility manager roles as needed to ensure that certification is performed by the appropriate facility personnel. A facility manager may also add other staff or consultants to the facility account as Facility Reporters. Please see page 2-18 of the User's Guide for more information. For changing "reporters" to "managers" and vice versa within the Reporting Tool, please contact ghgreport@arb.ca.gov for assistance. The User's Guide is here: http://www.arb.ca.gov/cc/reporting/ghg-rep/ghgtoolusersguide.pdf.

22. Q: Why does the Reporting Tool require a measured **high heating value** (HHV) if my general stationary combustion (GSC) facility is allowed to use the default HHV and emission factor in Appendix A?

    A: A default HHV is only provided in the Reporting Tool for the fuel "Natural Gas-Unspecified (Weighted U.S. Average)." If you choose this fuel type, the default factors will be available to you in the emitting activity tab. The other natural gas fuel types will require input of a HHV, which can be obtained from your fuel supplier.

23. Q: Where do I enter the **monthly HHV** values in the Reporting Tool?

A: The tool does not provide the capability to include monthly HHV inputs. You will need to calculate your emissions on a separate spreadsheet, and then enter this 'precalculated' annual average HHV and your annual fuel use. Then, because you precalculated the CO_2 emissions, you would select "95125(c) - Precalculated" from the calculation method pulldown menu. You will be able to use the default emission factors in the calculation tool for your CH_4 and N_2O emissions.

24. Q: Many facilities are likely to hire **consultants** to assist them in preparing their online GHG reports. It would be helpful if your site had some form of **guest login** so that people other than actual reporting firms can login and test the site.

A: The GHG Tool Training Site has been set up for this purpose. Send ARB a request at ghgreport@arb.ca.gov and we will create a training account for you. For actual emissions reporting, facility managers can easily add consultants or others to their facility GHG Reporting Tool account(s), which allows access to the facility data. See page 2-18 of the tool Users Guide for instructions, here: http://www.arb.ca.gov/cc/reporting/ghg-rep/ghgtoolusersguide.pdf

25. Q: How many **decimal places** are required to be reported for fuel use, HHV, and greenhouse gases?

A: Please use good scientific judgment when reporting emissions. In general, reporters will know the precision in their various fuel use and analytical measurements. If you are concerned with misrepresenting precision or rounding errors, you may report emissions with as much precision as your meter or calculation allows. Document your rounding so that a verifier will be able to reproduce your calculation.

26. Q: If a facility is both a cogeneration and a general stationary combustion facility, which do we designate as **primary sector** and which is **secondary**?

A: Your primary business determines your primary reporting sector, and you may look to your NAICS code for this. See the stepwise guide for electricity generating and cogeneration facilities for a full explanation. In some cases, operators of electricity generating facilities and cogeneration facilities will submit stand-alone reports. In other cases, electricity and cogeneration information will be submitted within the report of a power entity or another reporting sector, such as a cement plant, petroleum refinery, hydrogen plant, or general stationary combustion facility. Select "other" as the primary sector in the Reporting Tool when your primary business is not one of those listed.

27. Q: Can a cogeneration facility be classified as a **primary sector**?

A: Cogeneration is a secondary sector with one exception. The exception is when the operator's primary business is energy production and the facility is 100 percent cogeneration.

28. Q: Reporters are able to **attach supporting documents** to their emissions report in the Reporting Tool. What should be submitted? Are certain documents expected to be attached (scans of electricity bills and gas bills for the year, Excel spreadsheets with calculations), or is this strictly optional?

    A: The Reporting Tool may be used to provide information to ARB about related entities specified in §95104(a)(8)(A). Facilities with many devices may also attach a spreadsheet (see Tool for format) to report required device-level fuel use. There is no requirement to submit copies of fuel bills or meter readings. Please note that any documents submitted to the tool may be subject to public release.

29. Q: Where do you obtain the **EIA identifier number** for an electricity provider?

    A: ARB maintains a list of electricity providers and specified generating facilities with ARB identification numbers. Power entities reporting wholesale power transactions from specified sources are required to use ARB identification numbers for specified sources. You should use the ARB ID numbers whenever possible. If you do not see an ARB ID number for your provider or facility, please identify the facility by their EIA number if available, or ask ARB staff for assistance. The current list is posted here: http://www.arb.ca.gov/cc/reporting/ghg-rep/ghg-rep-power/ghg-rep-power.htm

30. Q: The spreadsheet version and pdf version of my GHG report both show that my "**supplemental**" emissions are counted twice. Is this an error in my report?

    A: In order to accommodate reporting for a variety of sectors, facility configurations, and fuel meter arrangements, it may be necessary to designate certain emitting activities as "supplemental." This prevents double-counting of facility emissions and fuel quantities. For example, cogeneration distributed emissions are always designated "supplemental." Also, generating unit level emissions that are captured with other sources at an upstream meter and included in a facility-level emitting activity must be designated "supplemental." Although there are probably ways to setup your emitting activities differently in the reporting tool and avoid counting "supplemental" emissions twice, it is not necessary to change this as long as your "summed" emissions are correct.

Reporting Combustion Emissions

31. Q: For GSC facilities burning landfill gas, biogas, or anaerobic digester gas, may a **default HHV** be used to estimate emissions?

    A: Yes, but only in limited circumstances, and not for electricity generation activities or cogeneration activities (except for abbreviated cogen reports). For GSC facilities subject to §95115, the regulation specifies that, "Where a high heat value is not supplied for a specific fuel type in Appendix A, the operator shall use the method provided in §95125(c), (d), or (h) to calculate CO_2 emissions." (§95115(b)(2)(C)). These methods require testing and measurement of the fuel characteristics or the use of generated steam to estimate emissions.

Because the regulation does not explicitly provide a default HHV for landfill gas, biogas, or anaerobic digester gas (i.e., biogases), the use of these measurement-based methods could be required. However, using information provided in Appendix A of the regulation, a default HHV for biogases may be readily derived. If measured HHV data are not available for biogases, the HHV of 524.39 Btu/standard cubic foot (scf) may be used. The default HHV is derived from Table 3 of Appendix A of the regulation which shows that 480,503 million Btu is equivalent to 916,301,950 scf. Dividing the Btu value by the scf value provides 524.39 Btu/scf. However, if the biogas is combusted for electricity generation or larger cogeneration activities, then the requirements from those sections of the regulation apply (§95111 and §95112) and the default HHV generally can not be used.

The default HHV may be used by facilities subject to §95115 of the regulation and cogeneration facilities allowed to use abbreviated reporting.

32. Q: Is a GSC facility required to report CH_4 and N_2O from a **flare** if there isn't a default emission factor for that fuel or fuel mixture in Appendix A?

A: Yes, all stationary combustion sources are reported. For a butane flare, use the factor in Table 6 for LPG, as the definition of LPG includes butane. In cases where there is not a relevant factor in Table 6, the emissions could likely be classified as *de minimis* and the factor that most closely resembles the fuel could be used.

33. Q: How are emissions reported under §95125(a) when a fuel invoice only lists the **energy content** (Btu or therms) and not the volume (scf)?

A: If only the energy content (BTU/therms) is listed on the invoice, the operator may use the relevant emission factor from Table 4 (in kg CO2/MMBtu) of Appendix A-7 to calculate CO_2 emissions. The operator must still report fuel volume, and should use the default HHV (or actual heat content if provided) to calculate and report volume (scf).

34. Q: Can an operator **change emission calculation methods** during the year, or in subsequent years?

A: For some fuels, the regulation provides the operator with several choices of fuel-based methods from which to report stationary combustion emissions. The use of more than one method in a given year is acceptable, and year-to-year changes are also acceptable, as long as the operator follows the specified reporting requirements for each fuel type. However, the verifier may want to investigate why different methods were used in order to better understand the facility's emissions sources. Any change in methodology must be documented in the change log (§95105(a)(12)).

However, where the regulation allows a choice of using a CEMS or a fuel-based method, the operator must determine which approach to use and continue to use it in all future reports (see §95103(a)(11)). When an operator elects to install a new CEMS, they may use either a fuel-based method or CEMS until January 1, 2011, but must use the new CEMS after that date.

35. Q: Are the GHG emissions produced from **flares and other destruction devices** (like VOC thermal oxidizers) considered combustion or process emissions?

A: This question is relevant for determining which emissions must be reported, as well as determining whether GSC reporting thresholds are triggered, since under the current regulation their applicability is determined solely on combustion emissions and not process emissions.

Emissions from gaseous materials burned at a facility for which a pilot gas is required to sustain combustion are in most cases considered process emissions. Examples of such process emissions include emissions from combustion of volatile organic compounds from paint booths and the use of afterburners for the destruction of waste gases that will not burn without a pilot gas.

Typically, General Stationary Combustion (GSC) facilities that do not have a NAICS code of 211111 (oil and gas production) will only report emissions from the combustion of fuels identified in Tables 4 and 5 of Appendix A of the regulation. This includes natural gas used as a pilot gas in destruction devices. Please contact ARB staff with questions.

36. Q: Section 95111(c)(8) for **start-up fuels** specifies which method(s) should be used for calculating stationary combustion CO_2 emissions. For our cogeneration plant, where we only use fossil fuel for start-ups, this sounds exactly how we utilize natural gas with the exception that the primary fuels are coal and petroleum coke with biomass as a supplemental fuel along with waste tires. Are we able to calculate natural gas CO_2 emissions under §95125(a)?

A: No. Because the majority of fuel combusted in this case is fossil fuel, §95111(c)(8) does not apply. Section 95111(c)(8) applies to cogeneration and electricity generating facilities that combust primarily biomass-derived fuels.

However, the operator may consider whether the emissions from combustion of the natural gas start-up fuel can be designated as *de minimis*. When the sum of CO_2e emissions from the selected combustion sources (in this case start-up operations) is *de minimis,* the operator can use an alternate methodology. The accuracy requirement for fuel-based emissions calculation methods, including the requirement to report fuel consumption accurately to within +/-5 percent, is relaxed. Instead, operators must be prepared to demonstrate with "reasonable assurance" that the sum of reported *de minimis* emissions does not exceed the limits of 3 percent or 20,000 MT CO_2e specified in §95103(a)(6).

37. Q: Can a partial year of data be identified as ***de minimis***?

A: No, sources (equipment, gasses, fuels) may be identified *de minimis*, but not partial years. If a source is *de minimis*, the entire year's worth of data must be identified as *de minimis*.

38. Q: For a combustion unit, can CH_4 and N_2O emissions be categorized as ***de minimis*** even if the CO_2 emissions from that fuel cannot be classified as *de minimis*?

    A: Yes, individual gasses may be classified as *de minimis* for the same fuel.

39. Q: When combusting natural gas that spans **multiple high heat value** ranges, is it necessary to break this out in the reporting tool?

    A: When selecting fuels associated with each emitting activity in the reporting tool, you may either choose a single range that is reflective of the majority of fuel used, or break out usage and emissions for the individual HHV ranges. For a fuel-based emissions calculation method, the operator must report emissions based on monthly natural gas quantities and the measured HHV or carbon content each month. Operators who may use the default HHV for natural gas must select Natural Gas (Unspecified, U.S. Avg.) in order to use the calculator built into the reporting tool.

40. Q: The emission factor for biomass derived fuels in Table 4 of the rule appendix is based on 12% **moisture content**. Is moisture content adjustment needed when calculating emissions if the measured moisture content of the fuel is different?

    A: Yes, fuel quantity and the emission factor must be in the same moisture basis when calculating emissions. You may refer to a chemistry textbook or other references for how to perform the moisture content adjustment calculation.

41. Q: When entering a quantity of solid fuel into the reporting tool, what **moisture content** should the fuel quantity be stated in?

    A: For non-biomass solid fuels (e.g. coal and petroleum coke), the rule does not specify a moisture content for reporting. Reporting fuel consumption in any moisture content is acceptable when entering data into the reporting tool, but note that fuel quantity and carbon content must be in the same moisture basis when performing the emission calculation. In contrast, the rule requires biomass fuels to be reported on a dry basis. See the applicable rule sections for specific requirements.

Fuel Measurement and Analysis

42. Q: Are utility gas meters adequate for meeting the +/-5 percent fuel measurement accuracy requirement? What documentation is required to demonstrate **accuracy within +/-5 percent**?

    A: Utility (retail) gas meters are assumed to meet the +/-5 percent fuel measurement accuracy requirement because they are controlled for revenue collection purposes. Fuel purchase records, provided by the supplier, will typically be sufficient for estimating facility fuel consumption. Documentation is not necessary to demonstrate accuracy of meters installed and maintained by the utility, and the facility operator subject to GHG reporting is not required to maintain calibration or maintenance information for the “revenue” meter. However, during verification, this information could possibly be requested from the fuel supplier if needed to evaluate fuel use accuracy. See Guidance for Fuel Analytical Data Management in Appendix A of the *Instructional Guidance* document.

43. Q: Please give examples of how the availability and **accuracy of fuel meters** determine when an operator needs to install fuel meters, when to report device level fuel consumption, and how to set up emitting activities. In particular, what about metering at the **facility and unit level** in electricity generation, and when a facility includes **more than one reporting sector** (such as a GSC with electricity generation)?

A: See Attachment 1 for detailed examples. If emissions are reported using a fuel-based methodology, emissions must be based on fuel measurements accurate to +/-5 percent. However, if an operator of an electricity generating facility has met this requirement at the facility level, the operator does not necessarily need to achieve the same level of accuracy when reporting sublevel emissions for individual electric generating units.

If the operator is able to meet the accuracy requirement when reporting all sublevel or secondary sector emissions, the operator can mark these emitting activities as summed and will not need to duplicate reporting at the facility level because the sublevel emissions will also be summed to the facility level in the operator's summary report.

The operator is required to report fuel consumption to the lowest level of metering. If the sublevel reporting of emissions and fuels accounts for the lowest level of fuel metering, there is no need to duplicate reporting by setting up fuel measurement devices at the facility level. If, however, the emitting activities set up by the operator do not reflect the lowest level of metering, the operator will need to set up devices in the tool to report fuel consumption as measured to the lowest meters. Device level reporting of fuel consumption does not need to meet the +/-5 percent accuracy requirement.

44. Q: Does the 5% **accuracy requirement** apply only to fuel meters? What constitutes a fuel meter for the purposes of assessing its accuracy?

A: Section 95103(a)(9) requires that the operator employ procedures for fuel use data measurement to achieve an accuracy of +/-5%, and that fuel use measurement devices be maintained and calibrated in a manner required to achieve this level of accuracy. Thus while fuel meters may be the most common type of fuel use measurement device, this requirement applies broadly to all procedures or devices that measure fuel use (mass or volume flow) when the data is used in emission calculations. It includes weigh scales and measurements of stock changes for solid, liquid, or gaseous fuels.

For the purposes of assessing meter accuracy, a meter consists of everything up until the data enters an electronic data management system, including the measuring device itself, piping around the meter to ensure developed flow, pressure and temperature probes, electronic sensors or readouts, wiring or signals connecting to a data collection device, and any other equipment required to report the data within +/-5% accuracy at the standard temperatures and pressures listed in the regulation. A verifier should take into account the inherent meter design accuracy, installation location, ongoing calibration and maintenance, operating conditions, etc. For example, if a gas flow meter is designed to measure a pressure difference to a high degree of accuracy, but it does not measure and correct for temperature, a verifier would need to assess the effect of this on the meter's overall accuracy. Similarly, it would not be able to achieve the design accuracy if it is not installed in a location consistent with the original equipment manufacturer specifications, or if it is measuring flows at temperatures and pressures outside of its optimal design range.

45. Q: Is the **steam flow meter** subject to the §95103(a)(8) 80% data capture requirement and the §95103(a)(9) +/-5% measurement accuracy requirement?

A: Steam is not considered a fuel, and it does not need to meet the Fuel Analytical Data Capture or Fuel Use Measurement Accuracy Requirements of §§95103(a)(8) and 95103(a)(9). Because steam is used as a surrogate for fuel when computing CO_2 emissions in §95125(h), we encourage facility operators to accurately quantify their steam to the extent feasible and demonstrate every reasonable effort to obtain a data capture rate of 100 percent for the report year. However, if the operators were unable to meet 80% capture or 95% measurement accuracy, it would not be a non-conformance with the regulation.

The facility still needs to estimate emissions such that the verifier can "determine whether there is a reasonable assurance that the reported facility emissions are within 95 percent of actual total emissions for the facility." [§95131(b)(11)] The reporter will need to provide reasonable estimates of the steam generation to meet this requirement.

46. Q: Is the verifier required to check **fuel metering**?

A: Yes, if they are used to calculate emissions. The regulation requires that fuel meters used in emissions calculations achieve an accuracy of +/-5% (§95103(a)(9)). Verifiers will use the risk assessments conducted as part of their sampling plans to determine which meters will be reviewed in greatest detail.

The meter must be evaluated for correct type and location, as well as maintenance and calibration records as needed. Original equipment manufacturer (OEM) specification sheets may be reviewed in some cases to check relevant parameters. All meters, including positive displacement, differential pressure, ultrasonic, thermal mass flow, coriolis, and turbine meters have different parameters that must be evaluated by the verifier to determine if the meter is fit-for-purpose. The verifiers also need to check that the appropriate molar volume conversion (MVC) factor is applied to greenhouse gas calculations for gas meters.

47. Q: Is not pulling an **orifice plate** during a reporting year an automatic non-conformance?

A: Not necessarily. An orifice inspection as part of regular meter calibration can be at a frequency that supports the demonstration of meter accuracy within +/-5%. This could be an annual inspection, or an inspection every few years, depending on the quality of the gas and other relevant factors. Please consider OEM specifications, manufacturer recommendations, industry standards, or other relevant guidance in regard to inspection frequency. Verifying evidence of meter accuracy usually involves the review of documentation of a physical inspection of the orifice plate as part of regular meter calibration, but other techniques can be used to demonstrate that the meter is accurate.

48. Q: If a digester gas meter is only required to be **calibrated** every 6 years, and the facility operator conducts the calibration at that frequency, does the verifier need to review the most recent calibration records, and is that all the verifier needs to do?

A: When reporters can demonstrate they were calibrating a fuel meter at a frequency that maintains +/-5% accuracy, that is sufficient. However, our experience with meters for digester gas has indicated that the lack of maintenance for several years and the potential variability in the quality of the digester gas can lead to build-up in the pipe that effectively decreases the pipe diameter and may lead to inaccurate measurements. The verifier may need to be sure other factors affecting measurement accuracy (installation location, operating conditions, OEM, etc.) are acceptable because this meter may not remain accurate between calibrations.

49. Q: If the specifications for a fuel meter require **annual calibration** but the operator has not calibrated the fuel meter within the past 2 years, is this an automatic non-conformance?

A: If the operator has evidence that the meter was calibrated any time before the reporting year, and can also provide evidence that the meter still reads within +/-5% after the reporting year, the verifier may assume that the readings were also within +/-5% during the reporting year. Without this evidence, the un-calibrated meter would not meet the fuel measurement accuracy requirement in §95103(a)(9) and the non-conformance would result in an adverse verification opinion.

50. Q: If a meter is within +/-5% **accuracy** for 10 months, but then fails for 2 months, is that a non-conformance?

A: It depends. If the data is considered missing data and the verifier is satisfied that the meter was accurate during the 10 months, the mean of the captured data may be used to substitute for the missing data. However, it is more likely that the meter is still providing data and therefore the data is not missing (the data is bad data, but there's still data being collected). In this case, the verifier should evaluate if the fuel use measurements <u>for the entire year</u> achieve an accuracy within +/-5%. If the measurement uncertainty in those two months is enough that there is not reasonable assurance the annual measurements are within +/-5%, this would lead to a non-conformance adverse opinion. The verifier would still need to evaluate whether that non-conformance would lead to a material misstatement.

51. Q: What should be done if a **meter is out of calibration or was not calibrated** during the reporting year?

A: Any meter out of calibration should be noted in the issues log and brought to the attention of the operator. For conformity with the regulation, all fuel use measurement devices used to calculate emissions must be maintained and calibrated to achieve an accuracy of +/-5% (§95103(a)(9)). Therefore any meter that collected data used in emissions calculations with accuracy less than 95% would be considered out of conformity. Process unit meters that have accuracy less than 95%, and are not used for fuel use measurement, would not be a non-conformance.

If a meter was not calibrated during the reporting year, the reporter has the option to provide calibration data from the year preceding the reporting year and for the most current calibration in order to demonstrate the accuracy of the meter between the two calibrations before and after the reporting year.

52. Q: If a fuel meter is not **temperature corrected**, is that a non-conformance and could that also lead to a material misstatement in the total emissions?

A: The verifier would need to assess (or have the operator determine) the impact of a lack of temperature correction, or use of a default temperature correction, on fuel measurement uncertainty. If possible, the reporter may be able to evaluate the error involved when using a meter which is not temperature compensated by measuring or estimating the ambient temperature of the gas, and the range of temperatures for that process. Using the ideal gas law, the reporter could estimate the volume error introduced due to the lack of temperature compensation when compared with the standard temperature and pressure (STP).

In the case of an orifice meter, differential pressure is measured, but static pressure, temperature, density and viscosity must also be known or measured to calculate the flow volume. This error would also need to be addressed during verification.

In some cases, there may not be a temperature probe for the fuel stream and a default is assumed in the calculation. This introduces greater uncertainty into the calculations that needs to be assessed, and the impact will depend on the deviation of the actual fuel temperature from the default assumption. The same would be true for static pressure, density, etc., if not directly measured. This would result in a non-conformance when the uncertainty introduced is great enough for the accuracy to be outside the +/-5% range. This effect must be taken into account with other factors affecting meter accuracy (such as installation location, design accuracy, etc). When there is a non-conformance, the possibility of a material misstatement must also be assessed.

53. Q: During short durations the facility burns a very small amount of fuel and the **orifice meter** is not accurate during that time. However, during normal operations, which is

95% of the time and which represents 99% of the annual emissions, the fuel flow is such that the meter is accurate. Is this a non-conformance?

A: Meters are designed to measure fuel during normal operations, but may not be accurate during all periods of operation, such as during periods of very low flow. In most cases, this represents a tiny fraction of total emissions and would not be a non-conformance with the regulation as long as annual fuel consumption is still measured within +/-5%. However, for peaker plants where operating times and schedules are highly variable, the verifier may need to spend additional time evaluating the accuracy of the fuel measurement and how the fuel meter was designed for the application.

54. Q: Why are there **two standard temperature and pressure conditions** listed in the regulation, and which one do I use?

A: The two standard temperature pressure conditions identified in the regulation are 20 degrees Celsius (68 degrees Fahrenheit) and absolute pressure of 760 mm of mercury or 60 degrees Fahrenheit and 1 atmosphere (§95102(181)). The operator should use the appropriate temperature and pressure conditions for that meter. If the operator is allowed to use the default emission factors or heating values, no conversion is required.

55. Q: May **gas chromatographs** be used for estimating high heat value (HHV) when using method GPA Standard 2261-00 provided in §95125(c)(1)(B) of the regulation?

A: Yes. Note 2 of the GPA 2261-00 states that, "Any gas chromatography is acceptable for the analysis of natural gas as long as the specifications for repeatability and reproducibility in section 9 over the component ranges listed in Table 1 are met or exceeded."

56. Q: Several of the **ASTM methods** cited in the regulation have been or are in the process of being updated. Laboratories generally use the updated methods. Will use of the updated methods be permitted under the regulation?

A: As ARB staff becomes aware of updated methods we will review them for consistency and equivalence with the methods cited in the regulation. Where it can be determined that the modifications in the laboratory method would not materially affect the outcome of the analysis for the test in question, use of the updated method may be permitted.

57. Q: What type of **natural gas testing** fulfills the monthly testing/sampling requirement?

A: The testing requirement varies by sector. If the facility falls into the General Stationary Combustion sector (except crude oil and natural gas production), the higher heating value (HHV) or carbon content testing of the natural gas is not currently required, and the heat values provided in Table 4 of Appendix A may be used with a default emission factor as shown in §95125(a) for natural gas, unspecified (Weighted U.S. Average).

For other sectors, including GSC facilities with electricity generating units or cogeneration systems and oil and gas production facilities, either HHV or carbon testing is required based on the specific requirements in the regulation (unless CEMS are used). The testing frequencies for natural gas (gaseous fuels) are provided in sections 95125(c) and (d) of the regulation, and are generally monthly. More frequent fuel testing is allowed to be used for calculating emissions – for example, daily rather than monthly HHV may be measured, and emissions calculated on a daily basis.

Facility operators may use the monthly higher heating values for pipeline natural gas (HHV between 975 and 1,100 Btu per scf) provided in their billing information by their utility. The methods used by the utilities for testing pipeline quality natural gas are considered sufficiently rigorous to meet ARB's requirement for greenhouse gas reporting. Billing records from the utilities are considered sufficient documentation for verification purposes.

58. Q: If you burn natural gas at a GSC facility and you know the **HHV for natural gas** from information **provided by the supplier**, can you still use the equation in §95125(b)(3) to estimate CH_4 and N_2O, or would you be required to use the equation under 95125(b)(2) and measure the HHV monthly according to §95125(c)?

A: HHV provided by a fuel supplier can be used under the requirements of §95125(c)(1)(B). Also, see §95125(c)(1)(A) where the operator may elect to use HHV provided by the supplier. You may use HHV from your supplier or the default values in the regulation to calculate CH_4 and N_2O according to §95125(b).

59. Q: Is a **belt or conveyor scale** the only acceptable approach under the regulation for **measuring solid fuels**? Would a fuel pile inventory approach be acceptable? The site does not currently employ belt or conveyor scales, but a gate scale weighs all fuels brought on-site to the facility. Periodic (quarterly) fuel pile surveys are used to quantify the existing fuel pile in order to make adjustments for fuel received vs. combusted in three units.

Would the calibration requirements regarding the gate scales need to match a quarterly calibration schedule identified for the belt/conveyor scales or would it default to the requirements of other fuel measurement devices in which calibration is required consistent with manufacturer's recommendations to maintain the specified +/-5 percent accuracy?

Would one of the fuel pile surveys need to occur exactly on December 31st to allow for an annual inventory adjustment? The site currently conducts a survey in early December before closing the financial books at the end of the year.

A: Solid fuels may be measured using any procedure sufficient to quantify fuel use accurately, including gate scales. The calibration schedule in §95103(a)(9) applies only to belt or conveyor scales when the operator is doing the fuel measurement, rather than the fuel supplier. For fuel pile surveys, a year-end "stock" estimate may be made if a fuel audit does not coincide with the end of the calendar year. In this case, the procedure must be well documented for review by a verifier.

60. Q: Is it acceptable to use **truck scale tickets** to confirm weight of solid fuel burned? If the truck weight scales are located at the fuel supplier, and owned by the fuel supplier, is the facility responsible for determining the accuracy of the scales, with requirements for calibration and maintenance?

A: It is reasonable to expect that truck weight tickets would meet the fuel measurement accuracy requirements of the reporting regulation, since they are the basis of a commercial transaction similar to gas revenue meters. In addition, the regulation does not require you to calibrate the scales used by an off-site fuel provider. A verifier may request access to scale calibration records, so acquisition of those records by the reporting facility is recommended though not required by the regulation.

Fuel consumption may extend beyond the immediate question of whether the weighing method is accurate on an annual basis. For solid fuels analyzed by the operator the regulation requires the operator to conduct a test at least monthly for carbon content from a composite of weekly samples per §95125(d). To weight these monthly carbon content values correctly over the course of a year, the operator needs to know how much fuel was consumed in each given month. This includes knowledge of how much fuel is on hand at the beginning and end of each month, and balancing those to ascertain how much was burned that month. Truck weight tickets tell you the weight of each load, but not how much fuel is burned in a given month unless whole loads match up to the beginning and end of the month. The "month" does not need to be a specific calendar month, but should be regular intervals of fuel estimation approximately twelve times per calendar year.

61. Q: Can fuel **carbon content** that is provided by a fuel supplier be used in the emissions calculation for solid fuels, or must the operator separately collect **weekly samples** to conduct a monthly test of carbon content?

A: The specification for a monthly test using weekly sub-samples in §95125(d)(1)(B) applies when carbon content is determined by the operator rather than the fuel supplier. As long as the fuel supplier is conducting sampling in accordance with the industry standard ASTM method for the fuel in question and transmitting the correct carbon values as determined for each shipment of fuel delivered to the operator, additional sampling is not required unless the operator has altered fuel composition. Note, however, that a verifier may seek documentation through the operator that sampling for the delivered fuel was conducted consistent with the standard laboratory practices for that fuel.

62. Q: Which **percent carbon** value from the **coal analysis** is used for calculating mass emissions from the fuel: as-received, air-dried, or dry (desiccated)?

A: Coal carbon content should be expressed in the same terms as the weight of coal measured. Thus, if the weight of coal measured before combustion is a wet weight, you should use this value and the wet weight carbon fraction to calculate CO_2 emissions.

63. Q: If only a **single shipment of solid fuel** is received for the reporting year, is there an alternative to the monthly solid fuel sampling and testing requirement?

A: Pursuant to sections 95125(c) and (d), heat content or carbon content of solid fuels must be measured monthly. However, if only a single shipment is received in that reporting year, it is possible that a single carbon content measurement would suffice for estimating emissions for that fuel, as long as the fuel use and moisture content are accurately measured monthly and the single carbon content measurement is correctly used for each of the monthly calculations. The moisture content would allow the reporter to estimate emissions accurately within +/-5% when applying the single carbon content measurement to the amount of fuel burned for that month in cases where the moisture content of the fuel varies. Please consult ARB staff if you need further assistance in compliance determination.

64. Q: Are **self-calibrating meters** subject to accuracy testing if it is original equipment?

A: The regulation does not specify a test protocol for fuel meter accuracy. Operators should consult original equipment manufacturer (OEM) specifications to ensure meters are installed and maintained to accuracy specifications within +/-5 percent.

65. Q: If the facility does not have devices for direct measurement, are **fuel purchase records** sufficient to satisfy the fuel use measurement accuracy requirement?

A: Fuel purchase records will typically be sufficient for quantifying fuel use. A verifier may request calibration documentation from the fuel supplier (via the facility) if there is a question.

66. Q: What happens if the **Original Equipment Manufacturer's** specifications are unavailable?

A: The facility operator may use the standards of a consensus-based standards organization.

67. Q: When there is **no flow** going through a fuel meter, it still registers a very small flow (positive or negative). Is it acceptable to replace these values with 0?

A: As long as the time period without flow can be verified, adjusting these values to zero is acceptable, subject to verifier review.

Biomass-Derived CO_2 Emissions

68. Q: Under §95125(h)(2) does the regulation allow for **fuel sampling** as an option, in lieu of exhaust sampling, to determine **biomass** emissions?

A: Yes, the regulation allows for calculation of biomass emissions from fuel sampling as an alternative to emissions sampling, to the extent testing of a fuel type is supported by ASTM D6866. Fuel samples collected for analysis should be representative and unbiased, consistent with other requirements of the regulation. Note that the requirement in §95125(h)(2) to gather a sample over a 24-hour period is for cases where exhaust samples are gathered for analysis, and would not apply when a fuel or fuel mixture is analyzed directly. The other collection and calculation provisions in §95125(h)(2) do apply to fuel samples, including the requirement that the ASTM analysis be conducted at least every 3 months.

69. Q: My facility is a wastewater treatment plant with a requirement to report as an electricity generator. We co-fire anaerobic digester gas (**biogas**) with natural gas in our reciprocating engine. How do I calculate my CO_2 emissions from this emitting activity?

A: Section 95111(c)(7)(B) of the regulation, for calculating CO_2 emissions for co-fired fuels, refers to §95111(c)(5) for biogas and §95111(c)(1) for natural gas. For biogas, §95111(c)(5) specifies methods 95125(c) higher heating value (HHV), or 95125(d) carbon content, or 95125(g) CEMS. If the natural gas has a HHV in the range of 975 ≤ HHV ≤ 1100 Btu/scf, you may use the same methods as biogas. If the HHV of the natural gas falls outside that range, you cannot use method 95125(c) based on HHV.

If you measure the volume of digester gas combusted (scf) and higher heating value (HHV in Btu/scf), these measurements can be used to calculate all three required GHGs for stationary combustion: CO_2, CH_4, and N_2O. To calculate CO_2, use method 95125(c) and the “biogas” default factor (104.06 kg CO_2/MMBtu) from Table 4 of Appendix A. To calculate CH_4 and N_2O, use method 95125(b) and the ARB default factors (g/MMBtu) for “digester gas” in Table 6.

If you measure the carbon content of your biogas, we encourage you to use the method in §95125(d) to calculate CO_2 emissions. Using the measured carbon content for your fuel will usually produce a more accurate emissions calculation.

70. Q: Are biomass-CO_2 emissions included together with the other emissions in evaluating **for material misstatement**?

A: Biomass emissions are included with all other emissions when evaluating for a material misstatement (§95102(113) and §95131(b)(11)).

71. Q: Are biomass-CO_2 emissions included together with the other emissions in calculating the **3% *de minimis* threshold**?

A: Biomass emissions are included with all other emissions when setting the *de minimis* threshold (§95103(a)(6)). The reporting tool automatically calculates the 3% threshold and displays the value in the *de minimis* emissions section of the report.

72. Q: What does **bone-dry** mean?

A: “Bone-dry” means biomass (usually in chipped form) at zero percent moisture. The mass of bone-dry biomass is determined by sampling the load of fuel for moisture content and then converting to a dry-basis measure such as bone-dry tons. If moisture content is not measured for every fuel load, average moisture content may be used, subject to verifier review.

73. Q: If 98% of the total emissions are from **biomass**, can I use the default emission factor?

A: If all of the fuels are at least 97% pure, the default emission factor is acceptable. If one type of biomass fuel is not pure (see §95102(164) for definition of “pure”), that mixed fuel may be subject to additional testing (ASTM D6866-06a). The reporter would have to provide evidence to the verifier that less than 30% of the fuel is waste-derived fuel in order not to have to conduct ASTM emissions testing.

Section 95125(h)(2) specifically addresses the requirement to quantify and report the fraction of CO_2 combustion emissions from biomass fuels separately from the CO_2 emissions from fossil fuels. In general an operator who combusts fuel mixtures that contain biomass or waste-derived fuels that contain biomass will need to conduct a fuel analysis to determine the portion of CO_2 attributed to biomass. The fuel analysis methodology that is required, ASTM D6866-06a, is specified in §95125(h)(2). It is feasible to use the methodology only when the total fuels being analyzed are at least 5% biomass. The expectation is that operators will know if their fuel mixtures are at least 5% biomass.

74. Q: When is the method in §95125(h)(2) applicable? May alternative methods for computing CO_2 emissions be used if **waste-derived fuels** are less than 30% by weight? Are the referenced percentages (e.g., 5% biomass and 30% waste derived fuels) based on annual average percent or a shorter term basis? Is the biomass content based on an individual fuel or mixture, or the total fuel stream combusted?

A: These questions are addressed in Item I-3, page 162 of the Final Statement of Reason document (http://www.arb.ca.gov/regact/2007/ghg2007/fsorghg.pdf).

CEMS (Continuous Emission Monitoring System)

75. Q: The **CEMS CO_2** emissions data for a cogeneration facility is monitored using a CEMS that meets the operator's requirements per 40 CFR Part 60. Does this comply with the ARB GHG reporting regulation?

A: If the CEMS complies with the U.S. EPA requirements you have specified, it is considered acceptable for GHG reporting in California. See guidance for method specified in §95125(g) in chapter 13 of the Instructional Guidance document.

76. Q: My facility has a CEMS system that meets requirements under 40 CFR Part 60 but it **measures O_2 concentrations instead of CO_2**. Can I use the CEMS data to determine CO_2 emissions?

A: If your facility combusts biomass or fossil fuels, §95125(g) allows you to use the O_2 concentration and flue gas flow measurements to determine CO_2 emissions using the methodology provided in 40 CFR Part 75, Appendix F. If you combust biomass, your annual source testing must demonstrate that when you compare the CO_2 concentrations you calculated using O_2 concentrations to measured CO_2 concentrations, the comparison meets the Relative Accuracy Test Audit requirements in 40 CFR Part 60, Appendix B, Performance Specification 3. Also, O_2 concentrations cannot be used to calculate CO_2 emissions from municipal solid waste and other non-standard fuels such as refinery fuel gas where conversion factors are not available in Part 75, Appendix F; a CEMS must measure CO_2 concentrations for these fuels.

If your facility is subject to 40 CFR Part 75, you are required to report CO_2 emissions based on the CO_2 data you give U.S. EPA to meet the Part 75 requirements. If your facility installs a new CEMS and reports using CEMS, you are required to measure CO_2 concentrations and flue gas flow.

77. Q: If my facility is reporting emissions using a CEMS, do I still need to **report fuel consumption**? Does my fuel meter need to meet the **+/-5** percent **accuracy** requirement?

A: You must report your fuel consumption, but because fuel use is not part of your emissions calculation for CO_2, your fuel meter would not need to meet the +/-5 percent accuracy requirement. However, you must still calculate CH_4 and N_2O emissions using measured fuel consumption, and consequently, the fuel measurements must meet the +/-5 percent accuracy requirement unless the CH_4 and N_2O emissions are classified as *de minimis*.

78. Q: If a generating facility is subject to 40 CFR Part 75 and required to report Part 75 CO_2 emissions to ARB as specified in §95111(c), is a verifier responsible for checking conformance with Part 75? **Can the verifier assume** that if U.S. EPA has accepted the data, the data will be accurate and in conformance with ARB's regulation?

A: If an operator follows 40 CFR Part 75 to calculate their CO_2 emissions as specified in §95111(c), the verifier is responsible for assessing conformance with the applicable methods for calculating emissions in Part 75. This includes both fuel-based methods and CEMS methods under Part 75. When fuel-based methods are used, assessing conformance includes ensuring that parameters such as heating value and/or carbon content have been sampled at the frequency required by Part 75. Depending on fuel type, Part 75 may allow more than one option for calculating CO_2 emissions, and a verifier should ensure that the operator's calculations conform to one of the accepted options (though not necessarily the most accurate option). If the verifier identifies errors in Part 75 calculations, this will be included in the verification findings and potentially affect materiality regardless of whether U.S. EPA has accepted the data.

Test Methods and Source Testing

79. Q. When can I use source test data to calculate emissions? Could I use source test data to calculate emissions for the **whole reporting period** as long as I had no significant changes to the process during the reporting period?

A. You may elect to use source test data based on a source test plan pre-approved by ARB for calculating CO_2 emissions from geothermal electricity generating facilities and from facilities that combust biomass solid fuels or waste-derived fuels (including municipal solid waste). In addition, source test data can be used to determine CO_2 process emissions from sulfur recovery, and N_2O or CH_4 combustion emissions for all fuel types. This includes CH_4 and N_2O as specified in §95125(b)(4) and for CO_2 as specified in §95125(h)(3).

You may only use source test data to calculate emissions if fuels and processes are consistent. The source test plan submitted to ARB must include the period that the emissions estimate is intended to cover and an explanation about how this characterizes the facility operation. The underlying assumption is that data collected and factors developed from source tests would be used to estimate the emissions for the entire reporting period. The test protocol and resulting data need to adequately address variability throughout the year. This should be demonstrated at the time the source test plan is submitted for review and approval.

Because source testing is a series of discrete sampling events used to approximate emissions over a much longer time frame than the actual sampling duration, source test data are used to estimate facility emissions both before and after the actual source test event(s).

80. Q: May I submit a **source test plan** for **several facilities**?

A: Yes. We encourage the use of source test data for multiple facilities and sources. However, ARB will need to approve all initial source test plans before testing begins.

81. Q: If the sector-specific reporting requirements allow **source testing**, what will my verifier review?

A: The verifier would likely review the following information:
a.) The facility's source test plan.
b.) A formal letter from ARB approving the facility's source test plan.
c.) The facility's most recent source test(s).
d.) Documentation that ARB (or the local air district) was notified and given the opportunity to observe the source test.
e.) The application of the output of the source test result in either a concentration or mass per unit of time or as a function of capacity or output metric used in the emissions data report.

Electricity Generating and Cogeneration Facilities

82. Q: When determining if a cogeneration system is subject to reporting, what emissions information is included? Is it the **distributed emissions** (CO_2) for electricity generation? Do I exclude the distributed emissions for thermal energy?

A: You will use the distributed emissions equations to compare distributed emissions (CO_2) for electricity generation to the reporting threshold. Include process CO_2 and biomass-derived CO_2 from stationary combustion, if applicable. See Chapter 9 of the *Instructional Guidance* for a full explanation.

83. Q: Would stationary combustion emissions from a cogeneration system or generating unit under common **operational control** within a larger facility (such as an oil and gas production facility) be included when assessing whether the larger facility exceeds the 25,000 MT CO_2 **reporting threshold**?

A: Yes. Electricity generating units (EGUs) and cogeneration emissions are included with other specified emissions when comparing total facility emissions to the reporting thresholds in §95101.

84. Q: If the facility nameplate generating capacity is less than 10 MW, and the facility uses the electricity on-site (except that a small amount of electricity goes to the grid), can the **abbreviated cogeneration report** specified in §95112(c) be submitted? Does the cogeneration system still meet the definition of the term "self-generation"?

A: Yes. An abbreviated report is an option if some portion of the generated electricity is dedicated to serving the on-site demand. GSCs and other large facilities (>25,000 MT CO_2) with cogeneration are not eligible to submit an abbreviated report.

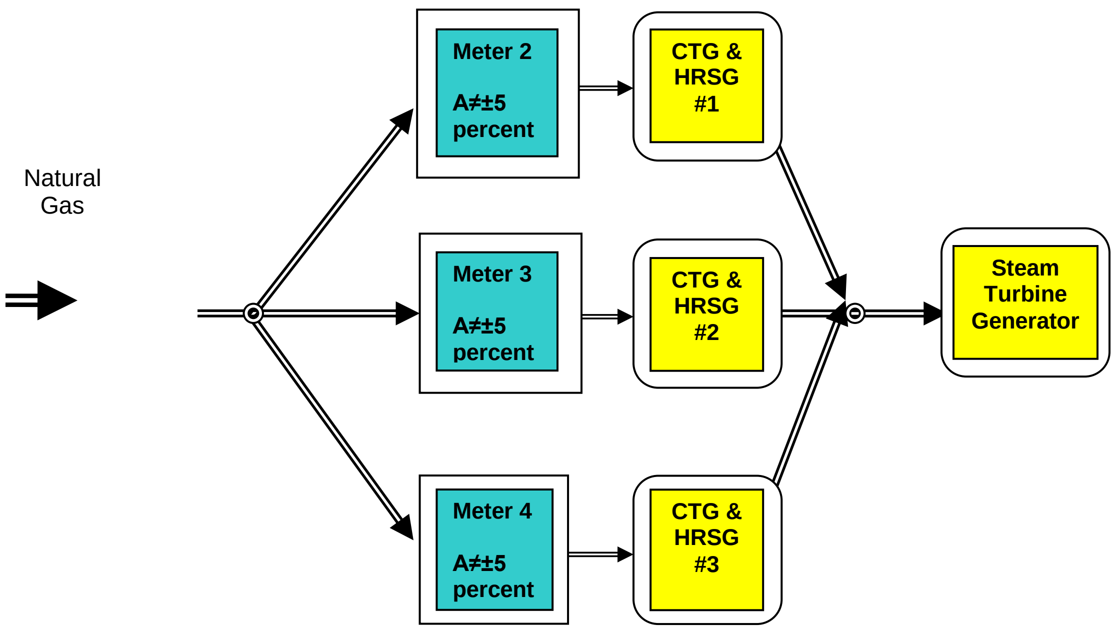
85. Q: What is the procedure for reporting **emissions and fuels data** for a **combined cycle power plant**?

A: The combined cycle electricity generating system is considered a single “generating unit” for purposes of reporting GHGs. [The definition from ARB’s GHG Reporting Regulation reads: “Generating unit” means any combination of physically connected generator(s), reactor(s), boiler(s), combustion turbine(s), or other prime mover(s) operated together to produce electric power.]

A 3-on-1 design is used as an example, illustrated below. The natural gas plant consists of three combustion turbines that drive electricity generators. Hot exhaust gas from each combustion turbine passes through an associated Heat Recovery Steam Generator (HRSG). The HRSGs make use of high temperature exhaust gas to heat water (heat exchange) and produce steam. Steam from the three HRSGs is combined to run a single steam turbine generator.

Two options are described to set up the emitting activities and fuel measurement devices are described, based on fuel meter accuracy considerations. In this example, the most accurate fuel meter is upstream of the combustion turbines. In the case where a fuel-based calculation is used and emitting activities are summed to the facility level, be sure the GHG calculations are based on fuel consumption data that are accurate to within +/-5 percent.

Option 1: Set up one emitting activity based on the most accurate meter to include the fuel combusted by all three combustion turbines. You will select “Combined Cycle Power Plant” under emitting activity type and designate the aggregation level as “summed.” Less accurate meters are located at each combustion turbine, so identify these meters under the “Devices” tab in the Reporting Tool.



Option 2: If you have a preference, you may set up four “emitting activities” under this single generating unit. This will allow you to report fuel consumption at the upstream meter for the combined cycle power plant as a whole, as well as for each combustion turbine. Since the emissions calculations for the individual combustion turbines are not based on fuel consumption monitoring accurate to within +/-5 percent, report these emitting activities as “supplemental.” Under this option, you will not need to report the combustion turbine meters under the “Devices” tab.

86. Q: What is the procedure for setting up and reporting **energy and production data** for a **combined cycle power plant**?

A: Step 1: You will select the “Energy Production” category under the “Energy and Production” tab in the Facility Information Module. This will allow you to enter your net power generation at both the facility level and generating unit level when you access the Annual Reporting Module.

Step 2: At the generating unit level for the “combined cycle power plant,” you will report, in a single data entry field, nameplate generating capacity (MW) that is the sum of all four generators (3 combustion turbine generators plus one steam turbine generator). This is reported in the "Facility Information" module under the "Generating Units" tab. You will do the same for net power generated (MWh). At the generating unit level for the "combined cycle power plant," you will report, in a single data entry field, net power generated (MWh) that is the sum of all four generators. Generating unit level net power generated is reported as a "new submission" in the Annual Reporting module. Select "Generating Unit" for the reporting level and "Energy and Production" for the submission type.

Step 3: Nameplate generating capacity and net power generated must also be entered for the facility level. Because you have one generating unit, the facility level information will be the same as the generating unit information***.*** *You do not need to set up redundant "emitting activities" at the facility level in order to report this information*. Facility level nameplate generating capacity is under the "Facility Details" tab in the Facility Information Module. Facility level net power generated is reported as a "new submission" in the Annual Reporting module. Select "Facility" for the reporting level and "Energy and Production" for the submission type. Please contact ARB staff if you need assistance.

87. Q: In the following scenario, is a **cogeneration facility subject to different reporting requirements** than a general stationary combustion facility?
    a. Under the operational control of an electric service provider
    b. Total emissions from all combustion sources >25,000 MT CO_2/yr
    c. Topping cycle plant
    d. Thermal energy is provided to a separate end user (separate operational control) that owns the land on which the cogeneration facility is located

    A: The electric service provider is subject to §95111 and will report as a retail provider that also operates a cogeneration facility. The electric service provider's responsibility is limited to facilities it operates and to activities related to providing energy to its end user customers, including auxiliary boilers, if applicable. In this example, the primary sector for this facility is cogeneration.

88. Q: If I operate **three electricity generating units** on the same property that are each under 1 MW and under 2,500 MT CO_2/year, do I need to submit a greenhouse gas data report?

    A: Scenario 1 - the three units combined do exceed 1MW and 2,500 MT CO_2/year. In this case, you would report for your generating units under §95111.

    Scenario 2 - the combined units do not exceed the thresholds and the generating units are the only combustion sources that would potentially trigger the mandatory reporting requirement. In this case, you are not required to report.

    Scenario 3 - the combined units do not exceed the thresholds, but they are part of a general stationary combustion facility or some other type of facility, such as a refinery, that is required to report. In this case, you are required to report emissions for each of these units as a simple combustion source. You would not need to meet the requirements of §95111.

89. Q: My site has two electricity generating units; one sells electricity to the grid and the other generates electricity for use on-site in the plant. Would I **add the two together** for reporting purposes?

A: In this case the distinction between the two generating units is made when reporting either electricity consumed on-site or electricity provided or sold. You will report nameplate generating capacity and net power generated individually at the generating unit level as well as added together at the facility level. This applies alike to electricity generating units and cogeneration systems. Note: "cogeneration systems" are also considered "generating units" for purposes of reporting.

90. Q: What is included in **net power generation?**

A: Net power generated means the gross generation minus station service or generating unit service power requirements (also known as parasitic load), expressed in megawatt hours (MWh) per year. In the case of cogeneration, net power generated includes on-site consumption of electricity for the purposes of a production process, power provided directly to end users, as well as wholesale power provided to the grid. An engineering estimate of station service or generating unit service power requirements is acceptable and does not need to meet the +/-5% accuracy requirement. See the following FAQ for further guidance on engineering estimates.

Net power generation is used for evaluating efficiency of generating units. Net power generation is intended to include only the unit service power requirements during the time when the unit is generating power. For generating facilities with a low capacity factor, whose total station service power requirement is greater than total generation for the year due (e.g. at a peaker plant), operators are strongly encouraged to not report a negative net generation number. Instead, we ask the operators to exclude from net power generation the power requirements during unit downtime or unit standby. An engineering estimate of the excluded power requirement is acceptable. However, reporting a negative net generation does not constitute a nonconformance under the current GHG reporting regulation, but operators should be aware of changes in definitions in the proposed Revisions to the Mandatory GHG Reporting Regulation (see http://www.arb.ca.gov/regact/2010/ghg2010/ghg2010.htm).

[Capacity factor is the ratio of the electrical energy produced by a generating unit for the period of time considered to the electrical energy that could have been produced at continuous full power operation during the same period.]

91. Q: What constitutes an acceptable **engineering calculation** for estimating parasitic load?

A: If a facility does not directly measure *both* gross generation and net generation, and parasitic load is also not directly measured, facility operators may use engineering principles to estimate parasitic load. Parasitic load is the sum of energy use of the auxiliary equipment that supports the electricity generation process, and these may include fans, pumps, drive motors, pollution control equipment, lighting, and other equipment. Satisfactory parasitic load quantification is either (a) a direct measurement of the energy used by the auxiliary equipment, (b) an engineering estimation based on an energy audit of the specific electricity generation system, or (c) an energy consumption accounting calculation to estimate the energy needs of each auxiliary equipment based on their physical specifications. The facility operator needs to demonstrate the reasonableness of the parasitic load estimate to the verifier.

92. Q: What constitutes electricity consumed on-site in §95112(a)(3)(C)? Does **electricity consumed on-site** refer to cogeneration electricity consumed on-site or both cogeneration electricity and grid electricity consumed?

A: Section 95112(a)(3)(C) refers to electricity generated by the cogeneration system and consumed on-site by other industrial processes other than electricity generation. Grid electricity consumed is reported in kWh as electricity usage (§95112(a)(6)). Electricity consumed on-site is the difference between net electricity generated and electricity provided or sold off-site. It excludes station service power requirement for the cogeneration system and any electricity acquired from off-site (either from the grid or from another facility). There are three common scenarios pertaining to reporting of electricity consumed on-site:

First scenario is for a cogeneration facility that meets all of the following: (1) not located within the same facility boundary as its thermal host; (2) not under the same operational control as its thermal host; and (3) has no other industrial processes on-site except cogeneration. Such a facility does not need to report electricity consumed on-site because any use of electricity on-site is considered parasitic load or station service electricity requirement. Station service or parasitic electricity use is not explicitly reported, but it is implied as the difference between the reported gross power generation quantity and the net power generation quantity.

Second scenario is an industrial/commercial/institutional facility whose primary business is not electricity generation that operates a cogeneration unit on-site. (Example: a cement plant or food processing facility with an on-site cogeneration unit.) When reporting electricity consumed on-site, such a facility shall report the electricity generated by the cogeneration unit that is used by on-site industrial processes other than electricity generation. If this quantity is not separately metered, an engineering estimation is acceptable and it does not need to meet the +/-5% accuracy requirement. If the facility has a contract to sell electricity to the grid or to supply electricity directly to another off-site end user, the operator should not include the contracted amount from the estimated electricity consumed on-site even if it is not separately metered.

Third scenario is a facility whose cogeneration system is within the same facility boundary as the thermal host but is operated and reported by a third party separate from the thermal host. In this case, the cogeneration operator will report electricity provided to the thermal host facility in two locations: (1) the Energy Production tab as "Amount consumed on-site" and (2) the "Energy provided or sold" tab with end-user NAICS code. Electricity sold to the grid is reported as "Electricity sold wholesale."

If a cogeneration arrangement does not fit any of the three scenarios described above, contact ARB staff for assistance. [See FAQ #111 for a similar question.]

93. Q: A facility whose primary business is neither electricity generation nor cogeneration includes an electricity generating unit (EGU) or a cogeneration unit that exceeds 1 MW and 2,500 MT CO_2. The total facility emissions are less than 25,000 MT CO_2. Does the operator report emissions from **all combustion sources** at the facility or only **emissions associated with electricity production**? What if the total emissions exceed 25,000 MT CO_2?

A: The operator is required to report emissions and other non-emissions data required in §95111 or §95112 related to energy production and distribution because the EGU or cogeneration unit exceeds the reporting thresholds. Reporting would also extend to electricity generation and distribution activities that emit fugitive emissions of HFC or SF_6.

If the operator is not required to report emissions from other sources at the facility because the facility's total emissions fall below the reporting threshold for general stationary combustion facilities, the operator would not need to report emissions for separate boilers which may be used continuously, intermittently, in standby mode, or for auxiliary thermal energy production.

However, if the annual emissions from the EGU or cogeneration system in combination with all other stationary combustion sources at the facility are $\geq$25,000 MT CO_2, the facility is also subject to the reporting requirements of a general stationary combustion facility (§95115), and all stationary combustion emissions must be reported.

94. Q: For an operator whose primary business is cogeneration, does natural gas usage need to be reported separately for combustion in a **backup boiler** and a **startup fuel for the main facility boiler**? The backup boiler is used only for thermal energy production and not electricity generation. The main facility boiler is used for both electricity generation and thermal energy production.

A: Emissions for the startup fuel are included in the total cogeneration emissions and in the distributed emissions calculations. Emissions from the backup or auxiliary boiler are not. For this reason, the fuel quantities and associated emissions are reported separately.

95. Q: A facility emits $\geq$ 25,000 MT CO_2 and includes EGUs or cogeneration units. Does the **operator quantify emissions** based on section §95111 or §95115 for those emissions sources not associated with energy production?

A: Emissions related to energy (electricity or thermal) production and distribution must be calculated using the methodologies specified in §95111 or §95112, as applicable. The exception is EGUs or cogeneration units that combined do not meet the reporting thresholds for electricity generating or cogeneration facilities. For these small units and for all other emissions sources at the facility, the operator would report emissions according to the section of the regulation that pertains to the operator's type of facility. These are §95110 for cement, §95113 for refineries, §95114 for hydrogen production, and §95115 for general stationary combustion facilities.

96. Q: Are **two separate cogeneration facilities** operated by a retail provider required to submit a **separate** GHG emissions report to CARB, or would the GHG emissions information be submitted under a comprehensive report from the electric service provider for both sources?

A: In the reporting tool, you will be able to submit a comprehensive report as a retail provider and include separate emissions reports from your cogeneration facilities. The emissions and applicable rules will still be by individual facility, but the submittal will include both sets of facility data.

97. Q: Which **NAICS Code** should I use if I operate a **cogeneration** facility?

A: Please select the NAICS Code that best describes the primary business at your facility. If you are an electric service provider that operates an electricity generating facility, a NAICS Code of 221112 (fossil fuel) may be the appropriate description. A specific NAICS code is available for wastewater treatment under the utility category. Universities and colleges have a specific code as well.

98. Q: At my cogeneration facility, I have two small **refrigeration units with HFCs**. How do I report these if there is no release?

A: You only need to report HFCs used in cooling units that support power generation or are used in heat transfers to cool stack gases.

99. Q: What constitutes **Useful Thermal Output**?

A: Useful thermal output refers to thermal energy made available for use in any industrial or commercial process, heating or cooling application, or delivered to other end users, i.e., total thermal energy made available for processes and applications other than electrical generation (see §95102(198) for definition). Steam used for power augmentation or NOx control, sent to a de-aerator, or sent to a cooling tower is not considered useful thermal energy. Also, this quantity should exclude thermal energy that is vented, discharged, or wasted *before* it is made available to processes and applications. Examples of such waste may include steam vented immediately after it was produced from the cogeneration unit but never reached any industrial process, and hot water discharged during warmer seasons due to lack of demand for heating application. However, thermal energy wasted *after* it has been utilized does not need to be subtracted from useful thermal output. Examples of such waste may include energy loss at the condenser, and steam vented between two industrial or commercial processes that sequentially utilize the steam/condensate in a series.

Subtracting the enthalpy in the returned condensate and make-up water is preferable, but either including or excluding the condensate enthalpy conforms under the current regulation. However, reporters should be aware of any changes to the definition in the proposed revisions to the Mandatory GHG Reporting Regulation (see http://www.arb.ca.gov/regact/2010/ghg2010/ghg2010.htm).

Furthermore, Useful Thermal Output includes only steam generated by equipment that is a part of the cogeneration system. For a facility with a cogeneration system and a backup boiler, whose steam generated is not used for electricity generation, the steam from the backup boiler should be excluded from Useful Thermal Output. That is because the backup boiler is not an integrated part of the cogeneration system.

100. Q: At a wastewater treatment plant with a cogeneration system fueled by biogas, the hot water generated by the cogeneration unit is sent to the **digester**. With the added heat, the digester generates more biogas, and the biogas is then sent to the cogeneration system to generate more power and heat. Is the hot water sent to biogas considered useful thermal output?

A: Yes, thermal energy used for heating a digester at a wastewater treatment plant is considered “useful” because maintaining temperatures at the digester is supporting a process that is not electricity generation, and such use of hot water is not solely for the purpose of electricity generation.

101. Q: How do you report **distributed emissions** for the following scenario? The exhaust from a gas turbine is routed through an HRSG and heat is used to produce steam. Of the total, one portion is re-injected into the gas turbine for power augmentation and emissions control and the remainder is supplied to an industrial process.

A: For distributed emissions estimates, please refer to Chapter 9 of ARB’s *Instructional Guidance*. The remainder supplied to the industrial process is considered useful thermal energy and is converted to MMBtu for the report year. Steam used for power augmentation or NOx control, sent to a de-aerator, sent to a cooling tower, or vented is not considered useful thermal energy. Only steam or heat provided to an end user or used on-site for production purposes or space heating is considered useful thermal energy.

102. Q: For a cogeneration unit, do **biomass** emissions need to be **distributed** pursuant to §95112(b)(4)?

A: When distributing emissions at a cogeneration system, only CO_2 emissions from combusting fossil fuels are distributed between thermal energy and electricity generation. Biomass emissions from a cogeneration unit do not need to be distributed.

103. Q: If a facility with a cogeneration system triggers the need to report as a general stationary combustion facility, should we identify the cogeneration as a **secondary sector** if the cogeneration system is less than 1 MW or emits less than 2,500 MT CO_2 (95101(b)(7))?

A: No, you should not designate the cogeneration system as a "secondary sector" in the Reporting Tool. That would incorrectly trigger other reporting requirements in the Reporting Tool which are not required to be reported. You can include stationary combustion emissions from the cogeneration at the facility level and use the methods allowed for GSCs.

If you would like to report the cogeneration emissions separately (as either summed, supplemental, or optional), you can set up a facility level emitting activity and give it a meaningful name. Please do not set up the emitting activity under the "Generating Unit" tab, as that would also incorrectly trigger other reporting requirements.

104. Q: If I have equipment that uses **SF_6** but I **contract another firm/entity** to conduct maintenance for me, do I need to report fugitive SF_6 or is the other firm/entity required to report?

A: If you are responsible for maintaining the equipment in proper working order you are required to report fugitive SF_6 and should work with your contractor to carefully track the usage and annually estimate these emissions.

105. Q: What happens if an electricity generating facility has not tracked SF_6 and is using a **mass balance approach** because the opening stock is missing?

A: If the data required to calculate the SF_6 emissions based on §95111(f) is missing, it is a non-conformance, unless the facility emissions are *de minimis* and can be calculated by another reasonable method.

106. Q: If a facility does not measure the mass of **SF_6**, but has not topped off any equipment, is that a non-conformance?

A: If the facility has evidence that SF_6 was not added to any existing equipment and other equipment has not been purchased or sold, the SF_6 should be identified as *de minimis*, and service logs used for the report. The reporter should consider identifying SF_6 as *de minimis* if they are not following the regulation where the inventory sheet is filled out with a beginning and ending mass balance inventory (or a detailed service log could be acceptable in some cases). Identifying SF_6 as *de minimis* allows the reporter to use a reasonable estimate when estimating a change in inventory (emissions for that year).

ARB recommends that the facility begin a more robust inventory system so future inventories follow the regulation method of a beginning and ending inventory. This does not mean the reporter must record a mass of every cylinder every year (although that would be preferable); instead the reporter would need a beginning inventory for all tanks, and then anytime a tank is used or discarded, the reporter would likely need to account for any leakage along with the mass of SF_6 used for topping up a breaker for that year by measuring the mass of SF_6 gas remaining in the cylinder and the difference between initial and ending mass attributed to that reporting year.

107. Q: Is it a non-conformance if **SF_6** is located on site but has not been included in the emissions data report, even if there were no SF_6 emissions during the reporting year?

A: If an electricity generation or cogeneration facility has SF_6 onsite but has not reported any amount of emissions of SF_6, including 0 emissions, this may be a nonconformance with §95111(a)(1)(J). The regulation (§95111(f)) requires that operators of generating facilities determine their SF_6 emissions using the U.S. EPA method specified in Appendix A. Operators will need to complete the SF_6 worksheet annually to be in conformance with the regulation, even if they would be reporting zero emissions in the current year.

The method is based on a stock change approach that accounts for SF_6 purchases, sales, and changes in nameplate capacity. Under this approach, the increment of SF_6 that leaks in any given year is not tracked, but rather it is reported as an emission when it is accounted for in the SF_6 mass balance. Operators who are not carefully tracking the information required by the regulation and the form in Appendix A of the regulation each year would also be at high risk of misstating their SF_6 emissions. By reporting 0 emissions for years where no inventory change occurred, it makes it clear to the verifier that the facility operator has tracked SF_6 and has completed the required reporting elements.

108. Q: If a facility is required to report **HFCs**, which HFCs are required to be reported?

A: Only HFCs listed in Appendix A with a global warming potential are required to be reported.

109. Q: If **generated electricity is not exported to the grid**, do you have to report emissions under §95111?

A: Yes. If you exceed the reporting threshold in §95101(b)(4) (or (7)), you must report under §95111.

110. Q: Do **useful thermal energy** and **output of a HRSG** reported under §95112(a)(4) need to be **measured accurately** within +/-5%?

A: The verifier needs to evaluate the method used to measure the energy to ensure that it is reasonable, but the regulation does not specify an accuracy requirement for useful thermal energy.

111. Q: For a cogeneration unit, what constitutes **thermal energy consumed on-site**? Does onsite and offsite thermal energy consumption need to be separately reported if it is not separately measured and nearly all of the useful thermal energy is sold to the offsite thermal host?

A: Reporting of thermal energy consumed on-site (§95112(a)(4)(A)(2)) refers to thermal energy generated on-site and consumed by other on-site industrial processes other than power generation. This quantity should not include steam used for power augmentation or NOx control, sent to a de-aerator, sent to a cooling tower, or vented. There are three common scenarios pertaining to reporting of thermal energy consumed on-site:

First scenario is for a cogeneration facility that meets all of the following: (1) not located within the same facility boundary as its thermal host; (2) not under the same operational control as its thermal host; and (3) has no other industrial process on-site except cogeneration. Such a facility does not report thermal energy consumed on-site because any use of steam on-site is presumably for supporting electricity generation and is not explicitly reported but excluded from the Useful Thermal Output quantity.

Second scenario is an industrial/commercial/institutional facility whose primary business is not electricity generation that operates a cogeneration unit on-site. (Example: a food processing facility or a university with on-site cogeneration unit.) When reporting thermal energy consumed on-site, such a facility shall report thermal energy generated by the cogeneration unit that is used by on-site processes and applications other than in support of electricity generation.

Third scenario is a facility whose cogeneration system is within the same facility boundary as the thermal host but is operated and reported by a third party separate from the thermal host. In this case, the cogeneration operator will report thermal energy provided to the thermal host facility in two locations: (1) the Energy Production tab as “Amount consumed on-site” and (2) the “Energy provided or sold” tab with end-user NAICS code.

If the amount of thermal energy consumed on-site is not separately measured, the operator may report this quantity based on an engineering estimation, and it does not need to meet the +/-5% accuracy requirement. If a cogeneration arrangement does not fit any of the three scenarios described above, please contact ARB staff for assistance. [See FAQ #92 for a similar question.]

112. Q: When can **aggregation of units** be used to report combined emissions for multiple generation units?

A: Reporters may aggregate the emissions from multiple engines as allowed in §95111(a)(3). All furthest downstream sub-meters that are in operation should be reported as required in §95103(a)(2), regardless of whether they meet the +/-5% accuracy requirement.

113. Q: Is **Net or Gross Power Generated** used for the P term in the §95112(b)(4)(A) and (B) distributed emissions calculation?

A: Net generation is used in the distributed emissions calculation. These equations use the electricity generation efficiency and thermal production efficiency to split the total emissions. Because electricity generation efficiency itself is evaluated by comparing net power generated with fuel input, Net Power Generated should be used in the efficiency calculation.

114. Q: For a cogeneration unit, what should be included in the **Total Fuel Input (F)** term in the §95112(b)(4)(A) efficiency calculation?

A: The Total Fuel Input (F) term is intended to include fuels that contribute to power generation (i.e. exclude fuels that contribute only to steam generation, such as supplemental firing). Because there are many possible ways to configure a cogeneration system, sometimes a facility operator may not be able to separate fuel use for steam generation from the total fuel use of the entire cogeneration system. If it is not possible to make the separation, it is acceptable to use the total fuel input of the cogeneration system as F.

115. Q: Under what circumstances can I use the assumed **efficiency values** of 0.35 for electricity generation or 0.80 for thermal energy production for the distributed emission calculation in §95112(b)(4)?

A: The electricity generation efficiency is calculated as eP = P/F, using the actual net power generated and the fuel consumption of the cogeneration system. (Also see the previous two FAQ entries regarding P and F.) The operator is only allowed to use the assumed value of 35% if for some unusual reason that the actual P and F quantities cannot be determined. In this case, the facility operator should demonstrate that P and F cannot be determined, and the verifier needs to check the reasonableness of the demonstration.

For thermal energy production efficiency, an operator may use one of the following: (a) a unit-specific efficiency value that is based on actual measurement, energy audit, or engineering estimation based on unit-specific parameters; (b) the Heat Recovery Steam Generator (HRSG) or boiler manufacturer's efficiency rating; or (c) the default value of 0.80 if none of the above is available. These three options are all acceptable for conformance purposes, but cogeneration unit operators are encouraged to use values specific to their unit (options a and b) before resorting to the default value of 0.80. If the operator used the assumed value of 0.80, the verifier should check that efficiency values using options a or b were not determined or not available.

116. Q: Should **nameplate capacity** be reported for equipment that did not operate during the reporting year?

A: If a generating unit is permanently shut down or decommissioned and it did not operate during the reporting year, the operator may exclude the nameplate capacity of this unit from the total facility nameplate capacity. The nameplate capacity of a generating unit that is not permanently shut down or decommissioned needs to be included in the total facility nameplate capacity even if it was not operated during the reporting year. Please contact ARB staff if additional assistance is needed in determination of operating status.

117. Q: For fuels that contain refinery fuel gas, flexigas, or associated gas, that are **mixed** prior to entering a facility subject to §95111, what is the requirement for **fuels testing**?

A: Because fuel is mixed prior to entering the facility, and outside the facility's operational control, it is considered one fuel and not subject to the mixture requirement. Emissions should be calculated using methods specified in §95111(c)(4).

118. Q: If a facility subject to **Part 75** has an identified problem with a Part 75 fuel meter that results in emissions that are not accurate, should the facility report that data to ARB, or should the reporter submit data based on a utility meter that is much more accurate (if available)?

A: Fuel meters subject to Part 75 must still meet the +/-5% fuel measurement accuracy requirements of this regulation when used in GHG emissions calculations. Reporters that have an identified error in their Part 75 emissions data should consult ARB on how to report the most accurate data.

119. Q: At an electricity generation facility, emissions are reported at both the **facility** and the individual **generating unit level**. The facility level emissions can be inputted directly or summed from the unit level inputs. Can the facility switch between the two methods once one has been selected?

A: Yes, but this creates serious problems in the Reporting Tool. Please contact ARB staff if you need assistance with reporting your unit level data. A year-to-year change to the method of reporting emissions should be noted in the change log (§95105(a)(12)) by the operator.

Cement Plants

120. Q: Does the regulation **define test methods** for CaO and MgO content in the clinker and non-carbonate CaO and MgO content in the clinker? Regarding the non-carbonate percentages, is this an analysis of the clinker or of the materials used to produce the clinker? For example, if fly ash is used as a component of the kiln feed mix, is the **fly ash tested** for non-carbonate CaO and MgO content or is the clinker tested?

A: Section 95110(c)(1)(A) of the regulation describes the derivation of the clinker emission factor but does not prescribe a particular test method for determining the respective CaO and MgO contents. All measurements are taken of the clinker and not of the feedstock. The variables are explicitly defined as the non-carbonate CaO content of clinker and the non-carbonate MgO content of clinker.

121. Q: Operators that burn **tires** are given the option of using §95125(c) requiring a measured heating value with a default carbon emission factor, or using the method from §95125(d) and measuring carbon content directly. Tires have significant operational, technical, and safety factors to consider when sampling and analyzing them. We do not currently have a **method to sample whole tires**. How do we handle this?

A: Section 95110(d)(7) requires cement plants that combust waste-derived fuels, such as tires, to calculate CO_2 emissions using the method provided in §95125(c), or §95125(d), or §95125(h)(3). However, the regulation does not prescribe a particular method to sample whole tires. Some facilities have developed a representative sampling procedure for whole tires that involves obtaining tire cross-sections from a representative group of tires. The tire samples are then homogenized prior to laboratory analysis. ARB staff will work to assist facilities in developing appropriate sampling protocols.

122. Q: Can you clarify if the **feedstock materials** for making cement have to be weighed to +/-5%?

A: Cement feedstock materials do not need to be weighed with an accuracy of +/-5%. The mass of clinker and cement kiln dust not recycled do not have to be measured within +/-5% because this material is not a fuel and therefore not subject to §95103(a)(9).

123. Q: If a facility has only two **fuel meters**, one associated with the cement production and the other associated with other stationary combustion sources, does this meet the requirements of the regulation?

A: One additional requirement for cement plants is to report kiln and non-kiln emissions separately. Otherwise, it will be common for reporters to aggregate equipment that burns the same fuel and identify the equipment in the emissions data report as "Other Stationary Combustion Sources".

Refinery and Hydrogen Plants

124. Q: Due to the definitions of naphtha, distillate fuel oil and diesel fuel, are **diesel** and **gasoline tanks** subject to the **fugitive emissions reporting** requirements?

A: Refineries are not required to calculate and report emissions from diesel and gasoline storage tanks. You must calculate and report emissions from storage tanks containing crude oil, naphtha, asphalt products, and distillate oil (#1,#2, and #4) using the U.S. EPA's TANKS model if these tanks are not connected to an active vapor recovery unit. If the tanks are connected to a vapor recovery unit, emissions resulting from their destruction (as a supplemental fuel or in a destruction device) will be reported using the method in §95113(d)(3) if the emissions are not reported as part of the facility flaring reports to the local air district. If they are included in the district flaring emissions report, either method (A) or (B) in §95113(d)(2) would apply.

125. Q: Are refineries required to report fugitive emissions of CH_4 and N_2O from wastewater treatment systems dedicated solely to **groundwater remediation**?

A: Groundwater does not meet the definition of wastewater and thus refiners are not required to report GHG emissions from groundwater remediation.

126. Q: To calculate CO_2 emissions from the **sulfur recovery unit** (SRU), the regulation indicates that you have to measure the flow of acid gas to the SRU. In working with several refineries, I have come across the issue that there are two streams into the SRU: one acid gas stream and one ammonia gas stream. When the regulation refers to "acid gas," does that mean the pure acid gas stream into the unit or the sum of the acid gas and ammonia gas streams? Furthermore, if the regulation only intends for the inclusion of the pure acid gas stream, is the ammonia gas stream accounted for elsewhere or just not included in the inventory?

A: The sour gas that is sent to an SRU contains many compounds, such as CO_2, hydrocarbons, mercaptans and ammonia. To calculate CO_2 emissions from the SRU you will need to consider all gas streams sent to the SRU. If you feel that the default molecular fraction of CO_2 that is provided in the regulation is not appropriate for one or more of the streams entering the SRU, you may elect to use an ARB approved source test plan to better characterize the CO_2 content of a particular flow.

127. Q: In some cases, process CO_2 in **sour gas** streams is already reported upstream and therefore would be double-counted if reported again under the sulfur recovery unit. Should the reporter report zero emissions, or still follow the method in §95113(b)(5)?

A: If the CO_2 emissions are reported elsewhere, there is no need to report anything for sulfur recovery process emissions. It should be well documented in the GHG Inventory program why using the regulation method would result in double counting, and the verifier would need to carefully evaluate the emissions data report to ensure emissions are properly accounted for in the report year. In some cases, only part of the process CO_2 would be double counted and it would not be correct to assume zero emissions. If this is the case, the operator may need to classify the source as *de minimis* and develop an alternative method to estimate the fraction that is not double counted.

128. Q: There is a refinery with a closed wastewater treatment operation that has no effluent discharge – all of the **water is injected into deep wells**. The required data for wastewater treatment (e.g., COD, sludge removed, N in effluent) are therefore not relevant to GHG emissions for this process, as the only GHG emissions are fugitive

component emissions from the equipment. Do those effluent measurements still need to be made?

A: You would not be required to determine wastewater COD, N or any other parameters if the wastewater was injected and there was no surface treatment involved.

129. Q: For **equipment fugitive** emissions at **refineries**, §95113(c)(4)(A) refers to all gas service components, but then §95113(c)(4)(A)(2) requires screening value measurements only for components in natural gas, refinery fuel gas, and PSA off-gas systems. Are all components in gas service included in the monitoring, recordkeeping, and reporting requirements, or just those in natural gas, refinery fuel gas, and PSA off-gas service?

A: The facility is required to extend LDAR screening to all components carrying natural gas, refinery fuel gas, and PSA off-gas. You should use gas composition data where available to convert from VOC to CH_4.

130. Q: For the **default flare emission** calculation, what exactly does "refinery feed throughput" mean (§95113(d)(2)(C))? Is that a dry value? Does this method of calculating emissions account for all GHG emissions from the flare, or would the emissions from fuel combusted as pilot and purge gas need to be accounted for separately?

A: Refinery feed throughput refers to the amount of crude oil processed by the facility. The units are cubic meters of crude per year so you will need to convert from barrels. This method covers only the material delivered to the flare for destruction. Thus emissions from pilot and purge gas would be calculated separately and reported.

131. Q: Regarding **periodic catalyst regeneration** and the data required per the regulation, the guidance document (pg. 10-10) states that the regulation does not specify an analytical methodology or measurement methodology. Does this mean that we have to take samples of the carbon on the spent/regenerated catalyst and analyze in a lab or are we able to calculate the weight percent of the carbon on the catalyst based on the amount of air used during the regeneration?

A: The regulation requires reporters to determine the weight fraction of carbon on both spent and regenerated catalyst. The regulation does not specify a method by which these variables are to be determined. You may use a method to determine these variables of your choosing, subject to verifier review. It is our understanding that actual sampling of the catalysts may be difficult and/or hazardous. You should thoroughly document the method you use (mass balance, etc.) so that its accuracy can be assessed during the verification process.

132. Q: Do GHG emissions associated with **off-site catalyst regeneration/reclamation** have to be reported by the refinery?

A: No, offsite emissions are not required to be reported.

133. Q: **FCC Coke burn rate calculations** - The K1, K2, and K3 factors stated in the regulation for the calculation for FCC coke burn rate assume a 386 standard factor scf/lb-mole, which is inconsistent with the standard conditions defined in the API Compendium (60°F and 1 atm, section 3.5 of the Compendium). The standard conditions of the Compendium results in a molar conversion factor of 379.3 scf/lbmole. Our instrumentation uses the 379 standard factor so our K1, K2, and K3 factors are slightly (~2 percent) different. We believe the 379 factor is the appropriate factor for us. Is it acceptable to use the 379 molar conversion factor, which is consistent with our instrumentation?

A: You should use the k-factors appropriate for your standard temperature.

134. Q: If all **carbon going into a hydrogen plant** is accounted for through mass balance, do fugitive emissions need to be quantified separately? The flaring and process vent sections note "...not reported using other methods..."; however, that statement is not present under the fugitive emissions section.

A: Fugitive emissions must be determined separately because the carbon is released as CH_4, not CO_2. Methane has a much greater GWP (21 versus 1) than CO_2. Use the S factor to correct for the carbon fraction reported elsewhere, and then quantify and report this S factor carbon appropriately.

135. Q: The regulation requires **tanks not under vapor recovery** to be included. How does blanketing with natural gas affect the need to report emissions from tanks storing crude oil, gas oil, etc?

A: Unless you recover a portion of your natural gas, you must assume all of it is released to the atmosphere as CH_4, and must be reported.

Verification

136. Q: Who can an operator select as a **verification body**?

A: An operator may contract with any ARB accredited verification body.

137. Q: If a facility verified its 2009 emissions data report in 2010, is **verification required again in 2011**?

A: Refineries, hydrogen plants, oil and gas production facilities, and electricity generation and cogeneration facilities >10MW that burn fossil fuel, are required to have their emissions data report verified annually (§95103(c)). For facilities subject to triennial verification that received an adverse verification opinion in 2010 for their 2009 report, verification in 2011 is recommended.

138. Q: Does an accredited verifier need to conduct the **site visit**?

A: Yes, an accredited verifier must be present during the site visit. For cement plants, power entities, and refineries, a sector-specific accredited verifier should be present. The requirement of §95131(4)(A-C) can only be met by an accredited verifier.

139. Q: Can a lead verifier that is a **subcontractor** for a verification team conduct the site visit, or does the lead verifier of the verification body have to be present for the site visit?

A: Any ARB accredited member of the verification team may conduct the site visit, including a subcontractor, lead verifier, or general verifier.

140. Q: What is meant by **"less-intensive"** verification for operators subject to annual verification?

A: "Less intensive" verification differs from full verification because data checks in the 2nd and 3rd year of a 3-year verification cycle may be based on the sampling plan from the 1st year of the cycle. Interim year less-intensive verification requires the same level of reasonable assurance from the verifier that the emissions report conforms to the regulation and contains no material misstatement. Less-intensive verification does not require a site visit, but the verifier *may* still need to visit the site if facility modifications have occurred in the past year resulting in new emission sources or if there have been changes to methodologies used in emission calculations as documented in the change log (§95105(c)(12)). For large or complex sites, it is expected that the lead verifier will choose to conduct a site visit every year.

Less-intensive verification principally focuses on data checks, and can be based on the sampling plan developed for the last full verification. The sampling plan involves a detailed risk assessment of the operator's emission sources and potential for errors, and thus does not account for significant changes in GHG emission sources or estimation methodology that may have occurred. Relying on a prior sampling plan during less intensive verification does not mean verifiers only recheck the same sources and documents targeted for data checks in prior years. The risk assessment in the sampling plan along with the prior issues log should help inform the verification team what sources to target for data checks and what documents to review during interim years.

141. Q: Should the verifier evaluate whether the facility is following the **recordkeeping** requirements, maintaining a **GHG inventory program**, and data completeness (internal audit, **QA/QC**) procedures?

A: The verifier is encouraged to evaluate whether the operator keeps the required emissions data report documentation and maintains a GHG inventory program, most likely during the site visit. The verifier may review document retention policies and the GHG inventory program as part of their review and evaluation of data management systems and the operator's GHG inventory program and QA/QC procedures. Any lack of recordkeeping, GHG inventory program or QA/QC procedures should be noted in the verifier's issues log. However, lack of this information may not directly result in a non-conformance adverse verification opinion because recordkeeping, the GHG inventory program, and QA/QC procedures are administrative requirements, and do not affect the emissions data report.

142. Q: Does the operator need to train people to maintain the **GHG inventory program** and data **QA/QC** procedures?

A: While there is no specific requirement for training, the operator must be able to demonstrate to the verifier that reported data is transparent, accurate, and complete (§95104(c)). If the verifier finds this not to be the case, the verifier must note it in the issues log and bring it to the attention of the operator. Without competently trained staff, it is unlikely that the operator will be able to submit an emissions data report that conforms to the regulation and is materially correct. Reviewing the training and qualifications of the staff that developed the emissions data report is a part of developing a verification plan because it can help verifiers identify high risk areas in the report. Lack of training itself would not result in an adverse opinion; however an adverse opinion may result when the emissions data report is prepared by staff that lacks adequate training. The verifier is not allowed to suggest training or implement a training program.

143. Q: If an operator is required to obtain **triennial** verification and no interim less intensive verification was required, is the verifier required to look at the data for the entire three year period?

A: No, only the data for the year of the required full verification is verified.

144. Q: What happens if a verifier suspects that an operator has knowingly submitted **false information** to a verification body?

A: The verifier should first contact the operator and determine the reason for the discrepancy. If the verifier still believes that the operator knowingly submitted false information, the verifier should contact ARB staff.

145. Q: Are verifiers and verification bodies subject to **enforcement action** by ARB?

A: Yes, if the verification body is unable to complete their work by the verification deadline, either because of lack of due diligence, or because they entered into contracts with too many operators, ARB could assess fines or rescind accreditation for non-compliance.

146. Q: If a verifier sees an unrelated **breach of environmental law** during the verification process, are they required to report it to ARB?

A: No, but professional duty requires the verifier to communicate violations that may cause safety or serious environmental concerns to the operator. Notifying an operator of a serious violation does not constitute a conflict of interest for the verifier.

147. Q: May a **verifier point out areas** where more accuracy should be strived for in the emissions report, or does that constitute consulting?

A: Verifiers may identify measurement techniques or processes where the accuracy could be improved, but may not consult on how the accuracy may be improved. Verifiers may also identify weaknesses in the GHG inventory program that may affect data quality, but cannot give any recommendations about how to address or improve these weaknesses. The verifier should note these instances in the issues log. Identifying weaknesses or areas of improvement is within the scope of verification services, but any specific recommendation for remedying these would constitute consulting services and create a conflict of interest. The operator is not compelled to obtain more accurate data or make other improvements as long as no material misstatement or non-conformance with the regulation exists.

148. Q: If a verifier finds that an operator has used a default emission factor and the operator has the capacity to **use more accurate**, site-specific data, is there an obligation for the operator to use the more accurate emission factor?

A: No, if the operator is allowed by the regulation to use the default emission factor, there is no obligation to be more accurate.

149. Q: If a verifier finds an error in the emissions data report, is the operator required to **fix the error**, even though it is not material?

A: Currently there is no requirement in the regulation to fix incorrect emissions data (§95104(d)(1)). However, the verifier is required to describe the error in the issues log, and provide an opportunity for the operator to fix the data. Errors will likely be required to be fixed beginning in 2012.

150. Q: Do the years of California Climate Action Registry (**CCAR**) verification count toward the six-year limit on verifiers? Do I have to change ARB verifiers when I am required to change **CCAR** verifiers?

A: Yes, the years of verification done for an operator under CCAR prior to beginning ARB mandatory reporting verification count toward the six year limit (§95130(a) and (b)). If you are using the same verifier for both the Climate Action Reserve and ARB and you reach the limit of six years with the Climate Action Reserve, you are also required to switch verifiers for ARB. Any prior relationship with a verifier in the Reserve will count towards the six year limit in the ARB reporting regulation.

151. Q: How robust does the **sampling plan** need to be to provide evidence that the verifier has reasonable assurance that the report is free of material misstatement and in conformance with the regulation (§95131(b)(9)(C))? Can the sampling plan be weighted to allow verifiers to focus on the most significant sources and not spend as much time on the smaller sources?

A: The sampling plan contains a ranking of the sources by contribution to total emissions and by calculation uncertainty to guide the verifier in determining which sources to review (§95131(b)(8)(B)&(C) and §95131(b)(9)). The verification team shall use their professional judgment in determining the sample size based on this risk analysis.

152. Q: May **verification services** begin before a facility operator has completed the emissions data report?

A: Yes, verification may begin as soon as the conflict of interest form has been approved by ARB (§95133(e)(1)). The verification body must not provide any consulting services or aid the operator in submitting the emissions data report.

153. Q: What does ARB mean by "**transparency**" of emissions data?

A: Operators are required by the regulation to have a transparent GHG Inventory Program (see §95104(b)&(c)), and are required to make all information used to calculate emissions and develop the emissions data report available to the verification team (see §95131(b)(6)). Operators must provide "transparency" to the satisfaction of the verifier; allowing them to clearly understand how emissions were calculated and relevant data was collected. If the verifier cannot fully understand a data management process or an operator's internal system related to GHG emissions, the verifier could find that there is a non-conformance, and would submit an adverse verification opinion.

154. Q: What is meant by "**original documents**" in §95131(b)(3)?

A: "Original documents" does not necessarily refer to the first version of a document. It refers to the fact that verifiers should be looking at original bills, invoices, reports, log books, contracts, purchase records, forms, or similar document from a utility, lab, or other service provider rather that relying on the values imputed into a spreadsheet when performing the verification.

Verification Body

155. Q: If a verification body has only two lead verifiers, and one of the leads leaves the firm during verification, the firm no longer meets the **accreditation** requirements of a verification body. What happens to the verification?

A: If during the course of providing verification services a verification body no longer has two lead verifiers, the verification body no longer is eligible to submit a verification opinion for an operator and should contact ARB as soon as possible.

156. Q: Can the verification team include **non-accredited "experts"** employed by the verification body to assist the verification team?

A: Yes, the non-accredited expert must be listed in the conflict of interest/notice of verification services (COI/NOVS) form along with the roles and responsibilities they will have during verification (§95131(a)(1)). A non-accredited "expert" should only be used in an advisory capacity, and not for providing verification services.

Independent Reviewer

157. Q: Does the lead verifier that conducts the independent review for the verification body (§95131(c)(1)) need to be accredited as a **sector specialist**?

A: No, only a single member of the verification team must have a sector accreditation if providing verification services for a refinery plant, cement plant, or power entity.

158. Q: Can an **independent reviewer** participate in a site visit? Can an independent reviewer conduct an interim review before the completion of the verification services in §95131(b)?

A: The independent reviewer may not participate in the site visit with the rest of verification team. The regulation requires that the independent reviewer not be involved with the verification services for that operator during that year. If desired, it would be acceptable for the independent reviewer to tour the facility separately from the rest of the verification team.

An independent reviewer may conduct an interim review of work products such as the verification plan and sampling plan to identify potential issues early on, but cannot be actively involved in drafting or revising these documents. The independent reviewer would still need to conduct a thorough review upon completion of verification services as specified in §95131(c).

Subcontractor

159. Q: Can a **sector-specific** accredited verifier be a subcontractor?

A: Yes.

160. Q: Can the **independent reviewer** or the **lead verifier** for the verification team be subcontracted?

A: No, the lead verifier for the verification team cannot be subcontracted by the verification body (see §95102(a)(204)), and the independent reviewer cannot be subcontracted by the verification body (see §95131(c)(1)).

161. Q: When an operator is required to change verification bodies, can a member of the **previous verification team** be a subcontractor for the new verification team?

A: No, every member of the new verification team must have not provided verification services for that facility within the past 3 years (§95133(b)(3)).

Verification Opinion

162. Q: What constitutes a positive opinion? Is it both **free of material misstatement and in conformance** with the regulation? Are these two items separate?

A: A positive opinion requires that the emissions data report is both free of material misstatements and conforms to the requirements of the Regulation. These two requirements are separate, and failure to meet either of these requirements would result in an adverse opinion (§95131(c)(2)(B)). It is possible to have a non-conformance that does not result in a material misstatement in total reported emissions. This would result in an adverse opinion, where the cause of the adverse opinion and a qualifying statement would be included in the verification opinion.

Conformity is following the requirements set forth in the regulation, and it should be assessed by verifiers as objectively as possible. Examples of non-conformances include: failure to meet fuel meter accuracy requirements, failure to meet data capture requirements, and failure to use a required calculation methodology when specified. A non-conformance at any source at the facility would result in an adverse opinion, regardless of whether the non-conformance results in a material misstatement or not.

Sources classified as *de minimis* as described in §95103(6) may use alternative estimation methods, and therefore non-conformances would generally only result at *de minimis* sources if they were improperly classified as such.

163. Q: What happens if an operator receives an **adverse opinion**?

A: Adverse opinions will be evaluated on a case by case basis. ARB will work with the operator to rectify the issues for the current year reporting as well as future year reporting. The goal is to have the most accurate inventory possible.

164. Q: What should the verifier put in the **qualifying comments** on the verification opinion form for an adverse verification opinion?

A: The qualifying statement should include any information that describes the cause of the adverse opinion. The qualifying comments must be provided to the operator (§95131(c)(2)(A)).

165. Q: What happens if a verification body and an operator are unable to **resolve a dispute** regarding the verification opinion?

A: The operator may petition the ARB Executive Officer to make a final decision on the verifiability of the emissions data report (§95131(c)(3)(A)).

Conflict Of Interest

166. Q: Can a verification body provide verification services for one facility for six years, and then shift to another facility owned by the **same corporation** for another **six years**?

A: The limitations in §95130(a) and (b) on the number of consecutive years that a verification body can be used apply to the operator and not the owner of the facility. If the two facilities are operated by different entities, §95130(a) and (b) would not prohibit the verification body from providing verification services at the second facility after working six years at the first facility. If the two facilities share operational control -- for example, if the common owner operates both facilities -- the operator could not hire the same verification body for at least three years after hiring the verification body for a six-year period at another of its facilities. The operator is the entity having authority to implement operational, environmental, health and safety policies (§95102(a)(140)). Please contact ARB for further clarification.

167. Q: Is conflict of interest between an operator and a verification body reviewed at the **facility level** or at the **corporate level**?

A: Conflict of interest is reviewed at the facility operator level. The operator is the entity having authority to implement operational, environmental, health and safety policies (§95102(a)(140)). Depending on the organization, operational control may be at the facility or a corporate level. If there are two facilities within an organization with local operational control, then conflict of interest is reviewed between the verification body and each facility separately.

168. Q: Are **gifts** considered a conflict of interest?

A: Gifts between anyone on the verification team and anyone affiliated with the operator could be considered a potential conflict of interest and should be disclosed in writing to ARB (§95133(g)(1)).

169. Q: Does past California Environmental Quality Act (**CEQA**) work that involves some project-related GHG impact analysis for the operator constitute a high conflict of interest?

A: Yes, this would constitute greenhouse gas related engineering analysis which falls under the high conflict of interest (§95133(b)(2)(B)).

170. Q: Would a **CEQA** project where the only GHG analysis was related to construction equipment emissions be considered a high conflict of interest?

A: Yes, this would constitute greenhouse gas related engineering analysis which falls under the high conflict of interest (§95133(b)(2)(B)).

171. Q: What is meant by "**managing any health, environment or safety functions**" in the list of high COI activities that any member of the verification body or related entity cannot have provided in the last three years (§95133(b)(2))?

A: This relates to any activities where a member of the verification body or related entity has assisted the operator in actually managing health, environment, or safety (HES) functions. This may include activities related to product safety, hazardous materials management, dangerous goods management, industrial hygiene and safety management, occupational health, waste management or any similar or related activities. If a member of the verification body assisted the operator in managing or overseeing HES programs, in developing HES management procedures, or in developing electronic HES data management systems, this would constitute a high COI. However, other HES assessments, studies, or compliance consulting that do not involve the management of the HES functions would not constitute a high conflict of interest, but would likely fall under a medium COI.

172. Q: Can an accredited verifier or verification body provide **consulting services** to a facility within 1 year of providing verification services for that facility and still maintain their accreditation as a verifier or verification body?

A: A verifier or verification body may provide consulting services; however, the verification body and operator risk the verification opinion being invalidated by the Executive Officer. The verification body is responsible for monitoring potential conflicts of interest for a period of one year after the completion of verification services. The verification body must notify ARB's Executive Officer within 30 days of entering into a contract with an operator (to provide consulting services, or as an employee) if the verification body has provided verification services within the previous year. If this process is not followed, the verifier or verification body risks revocation of their accreditation.

173. Q: If a verifier has acted as a consultant for an operator in compiling a non-greenhouse gas emissions **inventory** within the last three years, is it a high COI?

A: As long as the inventory did not contain any greenhouse gas emissions or any other functions specifically listed in §95133(b)(2), the conflict of interest would most likely be medium depending on the value of the services provided (see §95133(c)). Medium conflict of interest requires a mitigation plan to be submitted to ARB in order for the verification to move forward, and requires any individual with a potential COI to be removed from the verification team.

174. Q: If a lead verifier reviews information provided by an operator with the intention of entering into contract with that operator, is the verifier disqualified from conducting the **independent review** of the verification team's services and findings (§95131(c)(1))?

A: No, simply reviewing information would not disqualify the independent reviewer even if the response includes reviewing the emissions data report, references to person hours, the verification team or any other relevant information.

175. Q: If a **medium conflict** of interest is determined, what is ARB's process for evaluating the verifications body's risk mitigation proposal?

A: The risk mitigation proposal will be evaluated against §95133(d) and §95133(f)(4). The Executive Office will consider the nature of the previous work, the relationship of the verification body with the operator, the cost of the services performed, the degree affected individuals have been insulated, and any other information to ensure the potential conflict of interest has been mitigated.

Conformance and Material Misstatement

176. Q: What should a verification body do if it discovers a **non-conformance** that cannot be corrected?

A: It is the verification body's job to assess conformance with the requirements of the reporting regulation – verification bodies are not hired to render positive opinions, but to impartially render the correct verification opinion. While many non-conformance issues can be corrected before the verification deadline, in some cases corrections may not be possible. For example, if an operator did not collect required data or used inaccurate fuel meters, it will generally be impossible for them to correct those issues. If a non-conformance is discovered that cannot be corrected, the verification body is still responsible for completing the verification services, assessing for material misstatement, and issuing a verification opinion. The effect of the non-conformance on a material misstatement would still need to be assessed. If there is uncertainty regarding what constitutes a non-conformance, the verification body should contact ARB.

177. Q: If the reporter has not followed the correct calculation methods and **there is no way for the verifier to determine if there is a material misstatement**, is the verifier obligated to submit an adverse verification opinion?

A: Not using the correct calculation methods will lead to a non-conformance adverse opinion. If the verifier does not have reasonable assurance that no material misstatement is present, that also results in an adverse opinion and will be indicated in the verification opinion form.

178. Q: How much detail do verifiers need to give operators about **discrepancies** that are uncovered?

A: The verifier needs to communicate clearly to the operator what the discrepancy is and how they arrived at identifying the discrepancy without telling them how to remedy it. In some cases, the operator may be able to explain the issue, and the verifier may agree that there is not a discrepancy.

179. Q: What happens if a verifier finds a material misstatement in a calculation, or a non-conformance, from an **emissions year preceding the emission data report** currently being verified?

A: If a verifier uncovers a material misstatement or a non-conformance in the course of providing verification services for a previous year's emissions report, the verifier should note it in the issues log and notify the operator. For operators subject to annual verification, the operator may correct the erroneous report and have it re-verified.

180. Q: Is a verifier required to provide an adverse opinion for a facility with an unverifiable emissions source (**>20% missing data**)?

A: Yes (see §95103(a)(8)(A)). This is a non-conformance, unless the source is identified as *de minimis* and the method used to calculate emissions is reasonable (§95103(a)(6)).

181. Q: If a source is unverifiable due to >20% missing data, is it included in **material misstatement** evaluations?

A: Yes. Material misstatements are assessed based on total reported facility emissions, and this source would have been included in these emissions. A verifier would assess the unverifiable source based on available data to determine if a material misstatement exists. The verifier should first determine if the data is truly missing and not available from another source. If it is truly missing, the verifier can use professional judgment in how to best estimate the missing data. Some examples would be: back-calculation from other data, trending, engineering judgment or conducting a bounding calculation of highest and lowest possible emissions for the source during the reporting year based on captured data. If the uncertainty in the actual emissions for the unverifiable source is enough to potentially result in a 5% error in total reported facility emissions, the verifier would not be able to state with reasonable assurance that the report is free of material misstatement in the verification opinion. The equation for determining material misstatement is located in ARB's Instructional Guidance.

182. Q: Is non-conformance with the **fuel analytical data capture** requirement missing 20% of the total **fuel** data, or 20% of the data from an **emission source**?

A: Non conformity is missing 20% of the data for any parameter (i.e. mass, volume, flow rate, heat content, carbon content) used in emission calculations for each emissions source. See §95103(a)(8)(A).

183. Q: If an operator is **missing less than 20%** of the fuel analytical data, how is the operator supposed to report this data, and what are the obligations of the verifier in analyzing this data?

A: If less than 20% of the data is missing, and it is not being reported as *de minimis* or subject to the requirements of 40 CFR 60 or 75, the operator will substitute the missing data with the mean of the year's captured data. If the operator follows this methodology, the verifier would accept data to substitute for the missing data as accurate and not be required to consider uncertainties associated with using the mean value to substitute for missing data when evaluating for material misstatement. However, the effect of inaccuracies in the captured data should be taken into account. For example, if a verifier discovers a systematic error affecting the captured data, the systematic error would also affect the mean of the captured data which is used to fill in missing data.

184. Q: The data management system substitutes and **repeats the last captured value** for fuel use (or other parameters) for periods when the instrument was unable to take a reading. Is this considered captured data? Is this a non-conformance with §95103(a)(8) for not following the missing data substitution procedures?

A: Data substituted using methods in a data management system not derived from measured values is not captured data and is considered missing data under the regulation. Captured data must involve measured values, and not simply be an artifact of the data management system, such as repeating the last captured value. Verifiers will need to look very closely at underlying data because having a value present in a spreadsheet does not automatically imply that it is captured data.

Data substituted using methods other than the procedures outlined in §95103(a)(8) is a non-conformance with the regulation, and would need to be corrected in order to obtain a positive verification opinion. Repeating the last captured value does not conform to the method in §95103(a)(8).

185. Q: Is not using the **mean of the captured data** a non-conformance when replacing missing data?

A: Yes, the regulation requires the mean to be used. The verification body should contact ARB if there is evidence that this calculation is not representative of emissions for the period of time when data was missing.

186. Q: During periods when the unit is not operating, the meter still collects data where it reads **zero values**. How does this affect missing data substitution under §95103(a)(8) which requires use of “the mean value of the fuel analytical data results captured”? Are the zero values considered captured data that must be included in the mean?

A: Zero values recorded for fuel analytic data during periods when units were not operating are not considered captured data, as no emissions would be occurring during these periods. For the purposes of data substitution under §95103(a)(8), captured data refers to measured values during periods of operation. The fuel analytic capture rate used for data substitution also is based on periods of operation rather than all hours during the year.

For example, if a unit operated for 100 days out of the year, collection of data during 80 days of the unit’s operation could yield an 80% data capture rate. Substitution using the mean of the captured data would only include data captured during periods of operation.

187. Q: Does a verification body still issue an **adverse opinion** if the non-conformity is immaterial (i.e. does not result in a material misstatement)?

A: Yes, nonconformance and material misstatements are independent of each other when issuing the opinion.

188. Q: If a meter is non-conformant, is it automatically a **material misstatement**?

A: No, an assessment for material misstatement is based on the total reported emissions. If the emissions calculated from the non-conformant meter are not large, inaccuracies resulting from the faulty meter may not rise to the level of a material misstatement. A verifier may do a bounding calculation based on a conservative estimate of the meter's accuracy to assess whether a material misstatement exists. If there is no evidence to determine the accuracy of the meter, it is impossible for the verifier to be reasonably assured that there is no material misstatement. The verifier would need to triangulate available data to determine the likelihood of this resulting in a material misstatement.

189. Q: Once it is determined that a meter is in conformity with the regulation, is it **assumed it be 100% accurate**?

A: As long as there is no other evidence to suggest an error in the data from the meter, and the meter meets the accuracy requirements specified in the regulation and has been maintained and calibrated as required by the manufacturer, data collected from the meter would be assumed to be 100% accurate. The inherent uncertainty of fuel meters is not included in material misstatement assessments.

190. Q: If an operator did not report a **boiler** that only emitted 1% of the total emissions would this be a non-conformance?

A: For non-electricity generating facilities, the operator is not required to report the individual boiler fuel usage unless it is separately metered. Emissions can be calculated from fuel usage at the facility level for general combustion sources. Fuel usage at the facility level would include the boiler's fuel usage. If the boiler is on an independent fuel line and its fuel usage was not counted in the total facility fuel usage, it would be a nonconformance with the regulation even though it is not a material misstatement.

§95103(a)(2) requires the operator to monitor and report fuel consumption for the facility, and for each process unit or group of units where fuel use is separately metered. Verifiers are required in §95131(b)(5) to identify all emission sources and ensure all applicable emission sources have been included in the inventory.

For electricity generating facilities, the regulation requires emissions from electricity generation to be separately reported from non-electricity generating sources. In this case, if the boiler is not *de minimis*, a meter must be capable of measuring emissions only from electricity generation to +/-5%. This may require installation of a meter to account for fuel flowing to the boiler and to the generation equipment if the boiler or other emitting activity is not involved in the generation of electricity.

191. Q: In the event of a fuel analytical data monitoring **equipment breakdown**, does the 30 days to request an interim data collection procedure begin on the date the equipment breaks down or the date the breakdown is discovered?

A: The 30 day time-period starts from the date of equipment breakdown (§95103(a)(10)(B)).

192. Q: What happens if an analytical data monitoring equipment breakdown is not discovered until **after the 30 days** for requesting an interim data collection procedure has passed?

A: If it ultimately results in >20% of the data not being captured, it would be a non-conformance.

193. Q: Is the verifier responsible for verifying the **non-emissions information** required in §95104(a) of the regulation?

A: For §95104(a), the verifier should check that the information required in §95104(a)(1-4) has been included in the emissions data report. For these items, it is sufficient for the operator to fill in the data in the Reporting Tool. The geographic location (the longitude and latitude of the facility) may be checked with a GPS unit or online mapping tool. The information required in §95104(a)(5-7) and §95104(a)(9) is detailed, when applicable, in the sector reporting requirements in §§95110-95115, so verifiers do not need to separately verify this information under §95104. Verifiers also do not need to review the parent company information required in §95104(a)(8); it is excluded from verification under §95104(a)(8)(e), and ARB will ensure that either the facility/entity or the parent company has reported the required information.

The certification required in §95104(a)(10) is fulfilled when the operator certifies and submits the emissions data reported in the tool, so this will have been completed before the verifier is able to review the data.

194. Q: Solid fuel sampling required in §95125(c)(1)(A)(4) specifies that one in every 12 composite samples shall randomly be selected for **additional analysis**. If the reporter did not complete this analysis, is this a non-conformance?

A: Because the regulation does not specify what the reporter should do with this data, the lack of this analysis does not impact the verification opinion.

195. Q: What is the consequence of an operator **over-estimating emissions**?

A: An operator who reports emissions that are not within +/-5% of actual emissions would have a material misstatement in the data and receive an adverse verification opinion. The reporting regulation requires accurate reporting of GHG emissions. Overestimating emissions in an attempt to be “conservative” is not acceptable.

Site Visit

196. Q: When verifying electricity transactions for a power entity, can the verifier visit **OATI** or does the verifier have to visit the entity where the data resides?

A: The regulation requires a site visit to the facility or entity where data resides during the first year of verification. The verifier may also visit OATI, but must also conduct a site visit at the entity.

197. Q: Is a site visit required if the **facility is closed down** or now under different operational control?

A: If the facility has closed or the equipment is no longer located at the facility, a site visit would not likely be required, although the verifier would need to interview relevant staff as part of providing verification services. If the facility is under different operational control and it is difficult to gain access to the site, please contact ARB for assistance.

198. Q: If an electricity generation facility that burns primarily biomass uses **diesel as a start-up fuel**, is the facility required to have their data verified annually?

A: A biomass facility is subject to triennial verification if less than 3 percent of total emissions are from fossil fuels. If more than 3 percent of emissions are from fossil fuel, verification is also required in 2011.

Power Entities

Reporting Responsibility

199. Q: Is a marketer who reported imports or exports in a previous calendar year required to continue reporting in future years if no imports or exports are transacted?

A: An entity's status as a marketer can change from year to year, along with the obligation to file an emissions data report. Pursuant to the definition of marketer at §95102(a)(112), if for a given data year you are not a purchasing/selling entity at the first point of delivery in California for imports, or a purchasing/selling entity at the last point of receipt in California for exports, an emissions data report is not required.

In lieu of a report, a letter attesting to this situation with respect to the particular data year would assist in ARB record-keeping. Though this is not required by the regulation, it should prevent a follow-up inquiry later when a report has not been received. The letter may be addressed to the Emission Inventory Branch Chief, as follows:

Richard Bode
Chief, Emission Inventory Branch
California Air Resources Board
P.O. Box 2815
Sacramento, CA 95812

200. Q: How are imports, exports, and reporting responsibility determined based on NERC e-tag data?

A: Electricity is imported when the NERC e-tag shows the first point of receipt (source) is located outside the state of California and the final point of delivery (sink) is located inside the state. Electricity is exported when the NERC e-tag shows the first point of receipt (source) is located inside the state of California and the final point of delivery (sink) is located outside the state. The relevant physical path segment on the NERC e-tag is the segment that crosses the state border, with one point of receipt/point of delivery (POR/POD) outside the state and one inside. The importer or exporter is the Purchasing-Selling Entity (PSE), on the portion of the physical path that crosses the state border. E-tags listing CAISO as the importing or exporting PSE should be brought to the attention of ARB staff. Pursuant to CAISO protocol, all sales bid into the CAISO markets should show a final POD (sink) located inside the state of California. Note that electricity generated by a facility located outside the state of California and delivered into California is imported electricity, even when power does not cross Balancing Authority Area (BAA) boundaries and require an e-tag.

Wheeled power is reported separately from imports and exports. Wheeled power is electricity that has an e-tag documenting that both the first point of receipt (source) and the final point of delivery (sink) are located outside the state of California, with a physical path that includes at least one POR/POD inside the state. In some cases, power may be wheeled in the reverse direction.

Because at least one example has been brought to the attention of ARB staff, the following guidance is offered for the 2010 and 2011 data years for e-tags showing power transmitted back and forth across the state border multiple times. Corrections are not required, since many reporters do not typically check for this uncommon occurrence. Imports, exports, and wheels are clarified above based on whether the source and sink points for a particular e-tag are located inside or outside the state. In cases where more than one PSE has title to power on a segment that crosses the state border, only the last PSE on the e-tag should report the transaction.

Retail Providers Report all Known Imports

201. Q: Why are retail providers required to report **imported power** when they are the **first deliverer** and also when they are not the first deliverer? In the latter case, the first deliverer is another entity, a marketer or another retail provider. How does ARB ensure no **double counting**?

A: Retail providers report imports, exports, and power transactions inside California. They are required to indicate when they are the purchasing-selling entity at the first point of delivery inside CA. Marketers report imports and exports only when they are the first deliverer. When ARB analyzes the data, we will look at first deliverer data separately from other kinds of transactions. First deliverer data will include transactions by retail providers and by marketers. A separate data set will include all power transactions by retail providers. The two datasets will not be combined.

Clarification of POR/POD Locations

202. Q: How is reporting responsibility determined for electricity that is delivered to a point on or near the California state border?

A: See discussion of imports and exports in FAQ #200. The following POR/POD locations are clarified as to whether they are located inside or outside the state.

Inside or Outside State of California	Adjacent Balancing Authority	Physical Tie or Scheduling Point	TSIN Registry (POR/POD dropdown)[1]
Outside	AZPS	Eldorado 500	ELDORADO500
Outside	WALC	Mead 230	MEAD230
Outside	WALC	Mead 500	MEAD500
Outside	AZPS	Palo Verde (Trading Hub vs. Nuclear Power Plant)	PALOVERDE
Outside	BPA?	California – Oregon Border Trading Hub	COBH
Outside	LDWP/BPA	Nevada - Oregon Border (PDCI)	NOB
Outside	BPA	Captain Jack	CaptainJack
Outside	BPA	Malin 500 kV	MALIN500
Plant is outside	CFE	La Rosita Tie	CFEROA
Inside	CAISO	Existing Gen. Zone North of Path 15	NP15
Inside	CAISO	Existing Gen Zone South of Path 26	SP15
Inside	CAISO		ZP 26

Owned and Partially Owned Facilities and Hydro Contracts

203. Q: The regulation requires retail providers that hold contracts entitling them to a specified **percentage of a facility's generation** to treat the power as being from a **partially owned facility**. If the contract identifies a specific amount of power in MWh per year, would the facility be considered partially owned?

A: No. A facility is considered partially owned only if a fixed percentage of generation in the report year is stated in the contract or the contract is for all power generated. For example, if the contract is for 50,000 MWh per year, the power purchased or taken from the facility is reported as a transaction only. The retail provider is not required to "calculate" an ownership share at the end of the year. If the contract is for all the power generated by the facility, that is clearly 100 percent. The retail provider reports the power taken as a transaction in MWh per year and also reports an ownership share of 100 percent. If the contract states 50 percent of power generated from the facility, the retail provider reports the power taken as a transaction in MWh per year and also reports the ownership share as 50 percent. Some contracts for hydroelectricity specify a percentage of remaining electricity after

[1] http://www.caiso.com/docs/2002/04/26/200204261504396221.pdf

priority customers receive their allocation. Because this percentage is not fixed on net generation, these contracts are only reported as transactions and not reported as partially owned facilities.

204. Q: A retail provider has a contract to take **50 percent of power generated** from a resource mix of multiple facilities. Would the retail provider report ownership share in multiple facilities?

A: Possibly. The requirement to report ownership share pertains to contracts with specified facilities. Please contact ARB staff with questions.

Verification of Transactions

205. Q: Is verification required for retail providers that do not own or operate generation facilities?

A: Yes. Power transactions and retail sales are reported and must be verified.

206. Q: What are examples of **nonconformance** by retail providers and marketers?

A: Verifiers evaluate conformance by reviewing whether the requirements of the regulation have been followed. A few examples of reporting errors follow. If not corrected, these errors will result in findings of nonconformance:

- Missing source data and documents to support reported transactions;
- Failure to report electricity transactions, quantities of wholesale power purchased or taken from sources of generation that the reporter owns or operates;
- Failure to identify counterparties or power suppliers;
- Failure to report electricity purchased from renewable energy facilities.

207. Q: As a retail provider, is there a quick check I can use to determine if I might have a reporting error?

A: Yes, retail providers should be able to demonstrate an approximate power balance based on the following calculation:

Retail sales = Imports + Wholesale purchases/takes from within California - Exports - Wholesale sales with point of delivery in California

If electricity delivered and received does not balance, at least approximately, it is a good indication of a reporting error. The error may be in data entry, incomplete inventory of transaction sources, or misunderstanding of the regulation. This power balance equation does not apply to PacifiCorp and Sierra Pacific Power Company, both of which have contiguous service territories that extend out of state.

208. Q: How does a verifier evaluate **material misstatement** for electricity transactions?

A: The verifier performs independent sample calculations of imports, exports, purchases, and sales based on risk assessment and review of original data sources. When the verifier's sum of sampled transactions varies by 5 percent or less from the reported sample set, the verifier concludes with reasonable assurance that the data report is free of material misstatement. When the verifier's estimate of sampled transactions varies by more than 5 percent from the corresponding reported sample set, an adverse verification opinion will result in cases where the reporter is unwilling or unable to make corrections.

Region of Origin or Destination

209. Q: How are electricity transactions reported when they originate from unknown locations or known locations not listed as Pacific Northwest (PNW) or Southwest (SW)?

A: All imports and exports must be reported. Retail providers report unspecified power purchased from an unknown region as imports, and multi-jurisdictional retail providers designate region of origin as unknown. For the few cases when electricity originates from or is destined for a location not listed in the definitions of PNW or SW, the reporter must choose the region based on proximity or physical path. For example, electricity from Mexico is reported as SW. Electricity from Kansas also is reported as SW.

CAISO Transactions

210. Q: Given that ARB intended for electricity transactions to be reported as actual electricity deliveries and receipts consistent with NERC e-tagging requirements, what guidance can be provided for reporting CAISO market transactions?

A: Complications arise for some power entities that generate and purchase wholesale electricity within the CAISO Balancing Authority Area. CAISO market transactions may consist of purely financial arrangements, schedule adjustments, and actual physical power flows. Because CAISO accounting is based on net financial obligations, and e-tag records of delivered MWh are available only for transactions that cross BAA boundaries, some reporters may need to perform a power balance based on metered generation and consumption. These power entities will need to describe their policies and procedures, original data sources, data management systems, and data aggregation in sufficient detail in their on-site GHG Inventory Program documentation to demonstrate conformance to the regulation. In cases where power entities' data systems are unable to support disaggregating Integrated Forward Market (IFM) and Real Time Market (RTM) transactions, an estimate based on typical operation and management policy is sufficient. Contact ARB staff for clarification.

Attachment 1

Examples – Accuracy of Fuel Meters

*Please give examples of how the availability and **accuracy of fuel meters** determine when an operator needs to install fuel meters, when to report device level fuel consumption, and how to set up emitting activities.*

If emissions are reported using a fuel-based methodology, emissions must be based on fuel measurements accurate to +/-5 percent. However, if an operator of an electricity generating facility has met this requirement at the facility level, the operator does not necessarily need to achieve the same level of accuracy when reporting sublevel emissions for individual electric generating units.

If the operator is able to meet the accuracy requirement when reporting all sublevel or secondary sector emissions, then the operator can mark these emitting activities as "summed' and will not need to duplicate reporting at the facility level because the sublevel emissions will also be summed to the facility level in the operator's summary report.

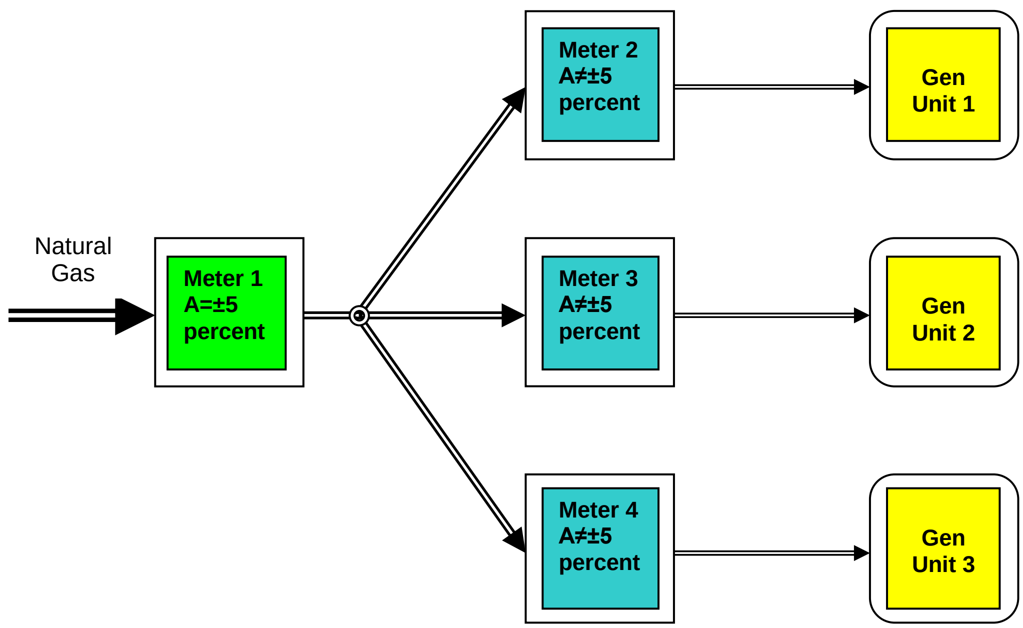
The operator is required to report fuel consumption to the lowest level of metering. If the sublevel reporting of emissions and fuels accounts for the lowest level of fuel metering, there is no need to duplicate reporting by setting up fuel devices at the facility level. If, however, the emitting activities set up by the operator do not reflect the lowest level of metering, then the operator will need to set up devices in the reporting tool to report fuel consumption as measured to the last level of metering. Device level reporting of fuel consumption does not need to meet the ±5 percent accuracy requirement. Here are three examples.

Example 1: An electricity generating facility is not subject to CFR 40 Part 75 and has 3 generating units that are 3 MW each with individual fuel meters. The fuel meters to the generating units are <u>not</u> accurate to +/-5 percent; however, the facility level revenue meter is. The operator plans to use a fuel-based methodology to report emissions. How should the operator report emissions and fuel consumption?

Operators of electricity generating facilities are required to report fuel use and emissions at both the facility level and at the generating unit level if fuel metering is available. In the example, the operator would set up an emitting activity at the facility level that represents emissions based on the revenue meter for all three generating units combined. The operator would report both emissions and fuel consumption for this facility level emitting activity and mark the emitting activity as "summed". This reporting meets the accuracy requirement.

Next, the operator would set up three generating units, each with an emitting activity. The operator reports emissions and fuel consumption for each unit. The emitting activities should be marked "supplemental" to avoid double counting with emissions reported at the facility level. The three unit level emitting activities meet the requirement to report emissions and fuel consumption at the unit level. There is no need to set up additional devices to report fuel usage because the meters to the units are the lowest level of metering.

Figure for Example 1

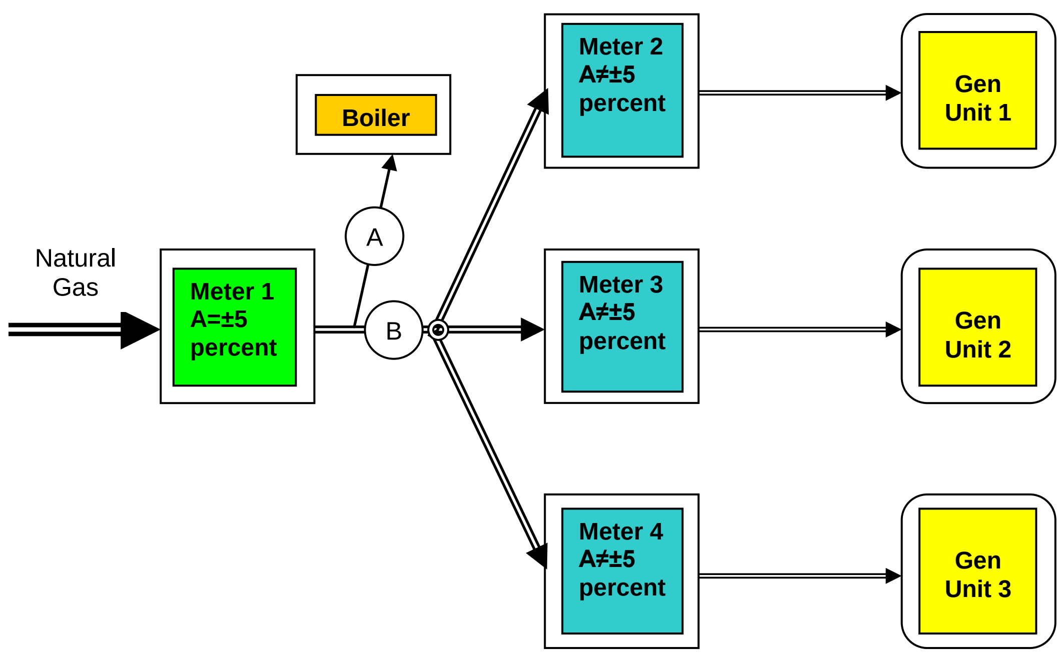


Example 2: An electricity generating facility has 3 generating units (3 MW each) with individual fuel meters and a boiler that is not metered. The fuel meters to the generating units are not accurate to +/- percent; however, the facility level revenue meter is sufficiently accurate. If the operator wants to use a fuel-based methodology to report emissions, how should the operator report emissions and fuel consumption?

There are two scenarios for a facility with such configuration. In the first scenario, if the facility is dedicated to generating electricity (with primary sector of electricity generation and no other industrial classification as a secondary sector), and the boiler is not used for other industrial or manufacturing purposes except for supporting electricity generation, the facility level revenue meter is sufficient for meeting the accuracy requirement of fuel metering. The operator may report fuel consumption that is accurate to +/-5 percent at the facility level, and accurate separation of fuel uses at the generating units and the boiler is not required. In the Reporting Tool the operator should create an emitting activity at the facility level marked “summed” based on the revenue meter. The operator would report emissions and fuel consumption for this emitting activity. Then the operator would set up each generating unit with separate emitting activities and an emitting activity at the facility level for the boiler, marking each of these four emitting activities as “supplemental,” and would report emissions and fuel consumption accordingly. There is no need to set up separate fuel meter “devices” because the fuel is already being reported for each generating unit to the lowest level of metering.

In the second scenario, if the facility's primary sector is general stationary combustion and secondary sector is electricity generation or cogeneration, and the boiler is used for other industrial or manufacturing purposes, the operator is required to report emissions and fuels associated with electricity generating units separately from other combustion sources on the facility. Because the boiler is not metered and the meters to the generating units are not accurate to +/-5 percent, there is no way to report the generating units separately, unless the emissions from the boiler can be included as *de minimis*. In that case, separate metering is not required. If the boiler is not *de minimis*, the operator must install a meter(s) to his boiler (see location "A" in the Figure for Example 2) that is accurate to
+/-5 percent, **or** install a meter (or meters) to the generating units (see location "B" in the Figure for example 2) that is accurate to +/-5 percent.

Figure for Example 2



If the operator chooses to install a meter to the boiler, the operator can calculate emissions for the facility using the revenue meter and then subtract emissions calculated for the boiler to determine emissions for the aggregated generating units. Similar to the first case, in the Reporting Tool the operator should create an emitting activity at the facility level marked "summed" based on the revenue meter. The operator would report emissions and fuel consumption for this emitting activity. Then the operator would set up each generating unit with separate emitting activities and an emitting activity at the facility level for the boiler, marking each of these four emitting activities as "supplemental," and would report emissions and fuel consumption accordingly. There is no need to set up separate fuel meter "devices" because the fuel is already being reported for each generating unit to the lowest level of metering.

Example 3: An electricity generating facility has 3 generating units (3 MW each) with individual fuel meters and a backup boiler that is not metered. The fuel meters to the generating units are not accurate to +/-5 percent; however, the facility level revenue meter is. The operator is subject to CFR 40 Part 75 and has CEMS on each of his generating units. The operator intends to report CO_2 using the CEMS data. How should the operator report emissions and fuel consumption?

Even though the operator will be using CEMS data to report CO_2 emissions for the units, the operator is still required to report fuel consumption and will need to use a fuel-based methodology to report N_2O and CH_4 for all sources and CO_2 for the boiler.

Step 1. Reporting N_2O, CH_4, and fuels at the facility level.
The operator should set up an emitting activity at the facility level based on the revenue meter and marks it "summed." This emitting activity includes all emission sources, including the boiler. The operator uses this emitting activity to report N_2O and CH_4 and fuel consumption for all sources combined.

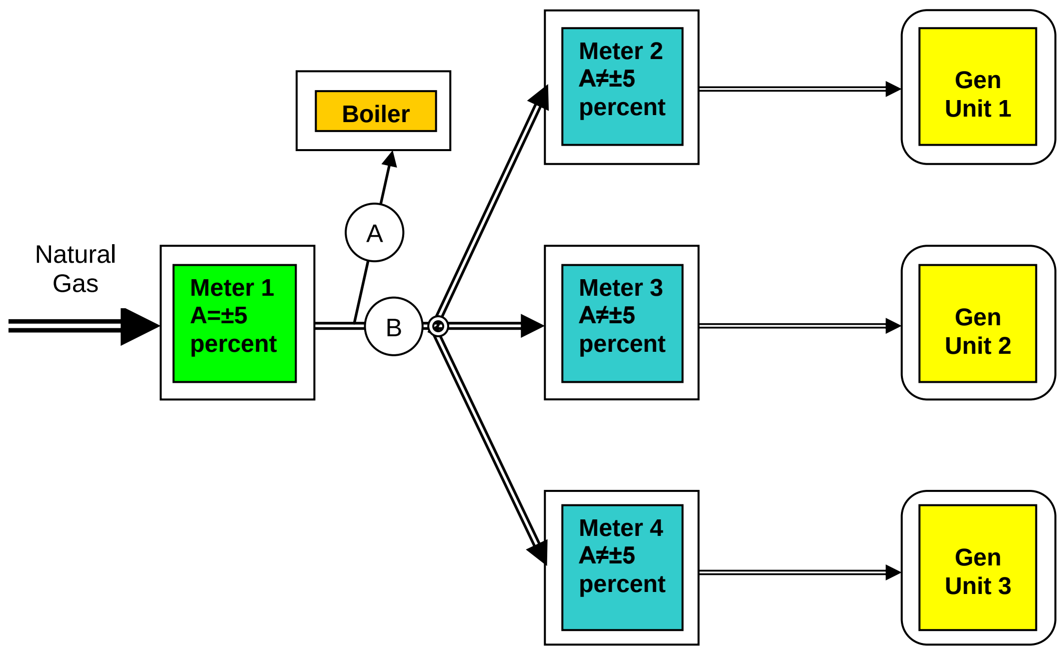
Step 2. Reporting N_2O, CH_4, and fuels at the unit level.
The operator creates generating units in the Reporting Tool for each unit and sets up an emitting activity under each unit marked "supplemental." The operator reports N_2O and CH_4 emissions and fuels for each unit.

Step 3. Reporting CO_2 at the unit level.
The operator sets up a second emitting activity under each unit marked "summed." The operator reports CO_2 emissions subject to CFR 40 Part 75. There is no need to associate a fuel type with this emitting activity. The operator will use "remaining emissions" when reporting CO_2.

Step 4. Reporting CO_2 for the boiler.
The operator sets up an emitting activity at the facility level for the boiler marked "summed." The CO_2 emissions for the boiler is pre-calculated by subtracting the sum of all CEMS-based CO_2 emissions from the generating units from the total CO_2 emissions calculated for the whole facility using a fuel-based method and the revenue meter. There is no need to associate a fuel type with this emitting activity. The operator will select "remaining emissions" when reporting CO_2 emissions for the boiler.

The operator has met the requirement to report CO_2 at the facility level by marking the sublevel reporting as "summed" to the facility level. Furthermore, all emissions were reported in a manner that meets the accuracy requirements of the regulation. There is no need to set up additional devices because the operator has already reported fuel consumption to the lowest level of metering when he/she reported for each generating unit.

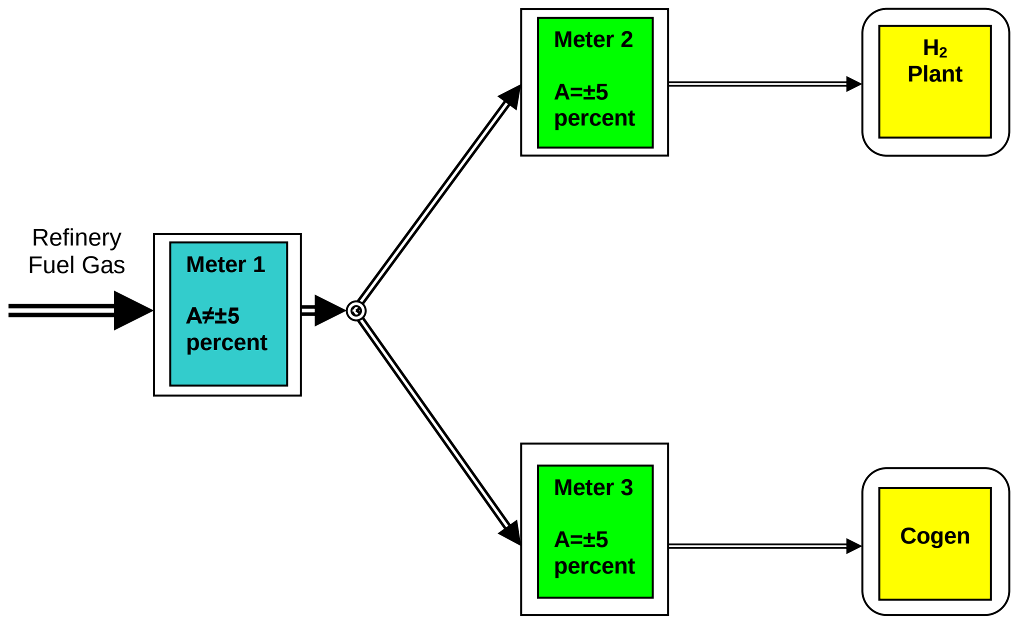
Figure for Example 3 where subject to CFR Part 75



Example 4: An oil refinery has a fuel meter that feeds a hydrogen plant and a cogeneration system on-site. The meter is NOT accurate to +/-5 percent. How should the operator report emissions and fuel consumption for the cogeneration system and the hydrogen plant?

The operator is required to address the discrete requirements of the regulation by estimating GHG emissions for the hydrogen plant and the cogeneration system under common operational control, separately from other refinery operations. To meet these requirements the operator must install meters that are accurate to +/-5 percent for both the hydrogen plant and the cogeneration system. An exception would be if either source is *de minimis*. For *de minimis* sources of emissions the operator may use a simplified methodology to calculate emissions without installing a meter.

Figure for Example 4



Example 4: Stationary combustion emissions from a hydrogen plant and cogeneration system must be calculated separately. Therefore, Meters 2 and 3 must meet the +/-5 percent accuracy requirement because data for these meters are used to calculate GHG emissions for the cogeneration facility and hydrogen plant. In this example, meter 1 is not required to meet the +/-5 percent accuracy requirement.

(Last page)