Guidance for Aggregation of Emitting Units

For the 2013 regulation of California's mandatory greenhouse gas reporting regulation

This document provides guidance for reporting and verifying aggregation of emitting units required to be reported pursuant to the Regulation for the Mandatory Reporting of Greenhouse Gas Emissions (title 17, California Code of Regulations, section 95100-95158) (reporting regulation or MRR), for 2013 data reported in 2014 and for data reported in future years. The California Air Resources Board (ARB) first approved the mandatory reporting regulation in 2007, with revisions in 2010, 2012, and 2013.[1] The 2013 MRR revisions became effective on January 1, 2014. **No substantive changes were made to this guidance document in 2014.**

Organization of this Guidance Document:

The first section of this guidance document summarizes the unit aggregation requirements. The next section, *Entering Information in the Reporting Tool,* provides instructional guidance for working with the California electronic Greenhouse Gas Reporting Tool (Cal e-GGRT) when reporting aggregated unit configuration. Note that although the reporting regulation requires certain types of emission units to be disaggregated, reporters are allowed to maintain the existing unit configurations in the tool in most circumstances. In these instances, additional information must be provided within the existing unit configuration as a way to comply with the amended unit disaggregation rule. Reporters should review this guidance in detail before making changes to their fuel metering practices and reporting tool configurations. Figure 1 provides a graphical guide to determining unit aggregation eligibility, followed by several examples of unit aggregation.

1. Applicable Rule Sections

Regulatory requirements for aggregating emission units can be found in section 98.36(c) of Title 40 of the Code of Federal Regulations (40 CFR) and sections 95112(b) and 95115(h) of the MRR. The criteria and limitations for aggregation are summarized below.

Section 95115(h), aggregation of stationary fuel combustion units:

Follow the requirements in 40 CFR §98.36(c), unless section 95115(h) specifies otherwise. The differences between section 95115(h) and 40 CFR §98.36(c) are described below.

Aggregation by Unit Type

Facility operators can only aggregate non-electricity-generating, stationary fuel combustion (SFC) units of the same type. The unit type categories are boiler, reciprocating internal combustion engine (RICE), turbine, process heater, and other

[1] The regulation is available at http://www.arb.ca.gov/cc/reporting/ghg-rep/regulation/mrr_regulation.htm.

(none of the above). (See section 95115(h)). Electricity generating units and cogeneration systems should never be aggregated with other SFC units unless a Tier 4 Methodology is used to report CO_2 emissions and follows the unit aggregation criteria in section 95112(b).

For a group of units that is considered "common pipe" or "aggregation of units" in 40 CFR §98.36(c) and in the Cal-e-GGRT reporting tool, reporters may maintain the existing configuration structure in the reporting tool and provide additional information to comply with the new limitation of aggregation by unit type specified in section 95115(h). See the *Entering Information in the Reporting Tool* section for further information.

Engineering Estimation is Acceptable
For the purpose of reporting fuel use at the unit type level, facility operators are not required to maintain accurate fuel measurement devices or have fuel meters at the unit type level if there is accurate fuel measurement upstream. Operators may use an engineering estimation to allocate total fuel quantity to the unit type groups. For example, if there is one accurate meter upstream of two boilers and three heaters that use the same fuel, and there is no meter at the individual unit level, the operator can aggregate the two boilers into a group and the three heaters into another group, and use an engineering estimation to report the fuel consumptions of the boilers group and the heaters group. As another example, if there is one accurate meter upstream of two boilers and one heater, and each of the three units has a meter without accuracy demonstration, the operator may use the fuel quantities measured by the unit-level meters to allocate the fuel quantity measured by the upstream meter. See Unit Aggregation Example 3 for additional guidance. The operator must be able to demonstrate to the verifier that the chosen engineering estimation method is reasonable, and the fuel consumption quantities at the "unit type" level add up to the accurate total upstream.

Aggregation by Industry Sector
In addition to the limitation of aggregating by unit type described above, units that belong to different industry sectors must not be aggregated together. A facility with operations that fall under multiple industry sectors (e.g., a facility includes a petroleum refinery and a hydrogen production operation within its overall facility boundary) would be reporting under more than one source category (as defined in section 95101(a)(1)(A)-(B) and 40 CFR Part 98 Tables A-3, A-4, A-5). Facility operators may aggregate SFC units that belong to the same industry sector if they belong to the same unit type category *and* meet the aggregation criteria in 40 CFR §98.36(c). However, the operators must not aggregate SFC units that belong to different industry sectors even within the same facility boundary. Electricity generation units (EGU) and electricity generating systems (EGS) must always be reported separately, regardless of the industry sector with which they are associated.

Common Stack
The facility operator may report aggregated units as a "common stack" configuration in the reporting tool if 40 CFR §98.36(c)(2) (Monitored common stack or duct

configuration) applies and is used by facility operators to report emissions. However, they need to report separately the fuel heat input (in MMBtu) of individual units or groups of units using the same aggregation criteria specified in section 95115(h) of the MRR. Engineering estimation is acceptable for determining fuel heat input and the +/- 5% accuracy is not required for the additional fuel heat input reporting.

Section 95112(b), aggregation of electricity generating units:

Follow the requirements in 40 CFR §98.36(c), unless sections 95112(b) and 95115(h) specify otherwise. The differences between section 95112(b) and 40 CFR §98.36(c) are described below.

Aggregation by Electricity Generation System
Facility operators may aggregate the individual units in an electricity generating system if all the units are integrated into the system. An electricity generating system can be a cogeneration system, a bigeneration system, a combined cycle electricity generation system, or a system with boilers producing steam to feed steam turbine generators. As a general rule, units are considered "integrated" into a single system if the units that generate electricity or thermal energy are not the same units that consume fuels, and the energy output from the system cannot be traced to fuel input at related SFC units in an undivided path in a system energy balance diagram. If there is more than one system present at the facility, each system must be reported separately. For more information, see the separate guidance for reporting electricity generating units available at ARB's Mandatory Reporting Regulation Guidance website.[2]

Standby/Auxiliary Boiler
In a cogeneration system, any standby or auxiliary boiler that does not contribute to electricity generation is not considered a part of the cogeneration system. (See section 95102(a) for the definition of "cogeneration.") The boiler should be reported separately from the cogeneration system. Having an accurate fuel measurement device on the standby/auxiliary boiler is preferred, but not required. If there is no meter on the boiler, facility operators may use engineering estimation to estimate the fuel consumption of the boiler. If there is a meter on the boiler that does not meet the calibration and accuracy requirements, but there is an accurate meter upstream of the boiler and the cogeneration system, they may use the boiler meter in engineering estimation even though the operator has not demonstrated accuracy on the boiler meter. The operator must be able to demonstrate to the verifier that the chosen method is reasonable, and that the estimated fuel consumption quantities at the lower level add up to the accurate total upstream.

On the other hand, if the standby/auxiliary boiler contributes to electricity generation by providing steam to a steam turbine generator some or all of the time, the boiler is considered an "integrated" part of the system and may be aggregated with the cogeneration system.

[2] Guidance website location: http://www.arb.ca.gov/cc/reporting/ghg-rep/guidance/guidance.htm

Part 75 Units in a System
Though 40 CFR §98.36(d)(1)(i) restricts aggregation of Part 75 units, facility operators are allowed to aggregate Part 75 units when reporting to ARB if those units are integrated into an electricity generation system. For example, in a "3-on-1" combined-cycle electricity generation system, the three gas turbine generators and the steam turbine generator may be aggregated, even though they are reported separately under the federal Part 75 program. However, Part 75 units must not be aggregated with non-Part 75 electricity generating units (EGU) or other non-EGU stationary fuel combustion units.

Aggregation of Simple-Cycle EGUs
Although aggregating multiple simple-cycle EGUs is not always prohibited by the reporting regulation if the EGU group meets all the criteria for unit aggregation, facility operators are strongly encouraged *not* to aggregate multiple simple-cycle EGUs together. For simple-cycle EGUs, reporting at the most disaggregated level possible, consistent with the reports prepared for other government agencies and/or for ARB in previous years, is strongly recommended. By reporting multiple simple-cycle EGUs at the most disaggregated level, operators provide a more accurate representation of their unit efficiency and enable cross-reference of different data sets for various data analyses.

To facilitate disaggregated reporting of EGUs, the unit-level fuel measurement devices are not required to meet all the calibration and accuracy requirements of the rule *if* there is a meter upstream that meets the calibration and accuracy requirements of section 95103(k). For operators that have maintained accurate unit-level meters and also have accurate billing meter upstream (in other words, the unit level meters and the billing meter are duplicative), and have chosen to use the unit-level meters to report emissions, they can always fall back on the billing meter if the unit level meter is out of compliance with the calibration/accuracy requirement for some time. However, such a scenario should not be a cause for aggregating simple-cycle EGUs. Operators may use engineering estimation when reporting unit-level fuel consumption if an accurate upstream measurement point is available. See Unit Aggregation Example 3 for a possible engineering estimation approach.

Verification of Reported Configuration

Verifiers are expected to review the configuration chosen for conformance with the reporting regulation. If the configuration is determined not to be in conformance, and the reporter does not make changes to address the finding, the verifier will note, at a minimum, a non-conformance pursuant to 95131(b)(10) where other requirements of this article (non-emissions information) must be evaluated for completeness and for reasonableness. The verification body will compile a list of reported data that was reviewed and found to be in conformance with the regulation in order to demonstrate to the reporting entity and ARB that this has been completed. A non-conformance related to any element in the emissions data report or supporting data triggers a qualified positive verification statement if the covered emissions or product data is otherwise accurate. Additionally, if the configuration affects total emissions reported (e.g., if non-calibrated meters are used), the verifier will include any associated uncertainty in their evaluation of material misstatement, which could result in, or contribute to, an adverse verification statement.

2. Entering Information in the Reporting Tool

Although the reporting rules require certain types of non-EGU stationary fuel combustion units to be disaggregated, in most circumstances, reporters are allowed to maintain the existing unit configurations in Cal e-GGRT if they provide additional information within the existing unit configuration as a way to comply with the amended unit disaggregation rule. Reporters should review this guidance in detail before making unnecessary changes to their fuel metering practices and reporting tool configuration.

Starting with 2012 data (reported in 2013), the Cal e-GGRT reporting tool has been modified to include a unit aggregation pull-down menu and a disaggregated fuel information table in each Subpart C and Subpart D aggregated unit configuration. The users will need to indicate the unit types (EGU, boiler, reciprocating internal combustion engine, turbine, process heater, other (none of the above), or multiple of the above) for a given aggregated unit configuration. If all the equipment in the aggregated unit configuration belongs to the same unit type, the configuration already meets the unit aggregation requirements in the rules. On the other hand, if the users had grouped more than one type of unit into a given configuration, they must report disaggregated fuel use information by unit type to meet the rule requirements. (Engineering estimation is acceptable if the reporters do not have meters at the disaggregated level.) The reporting of additional disaggregated fuel information is done in a table added to the respective configuration module in the 2013 version of Cal-e-GGRT.

An example: In the previous year, a reporter had reported an aggregated-unit configuration called "miscellaneous natural gas combustion sources," which includes 2 boilers and 10 heaters. Starting with 2013 reporting of 2012 data, the reporter may keep the same unit configuration in the tool, but must enter in a new table the percent of total fuels used by this configuration that are attributed to the 2 boilers and the 10 heaters. The table might look like this:

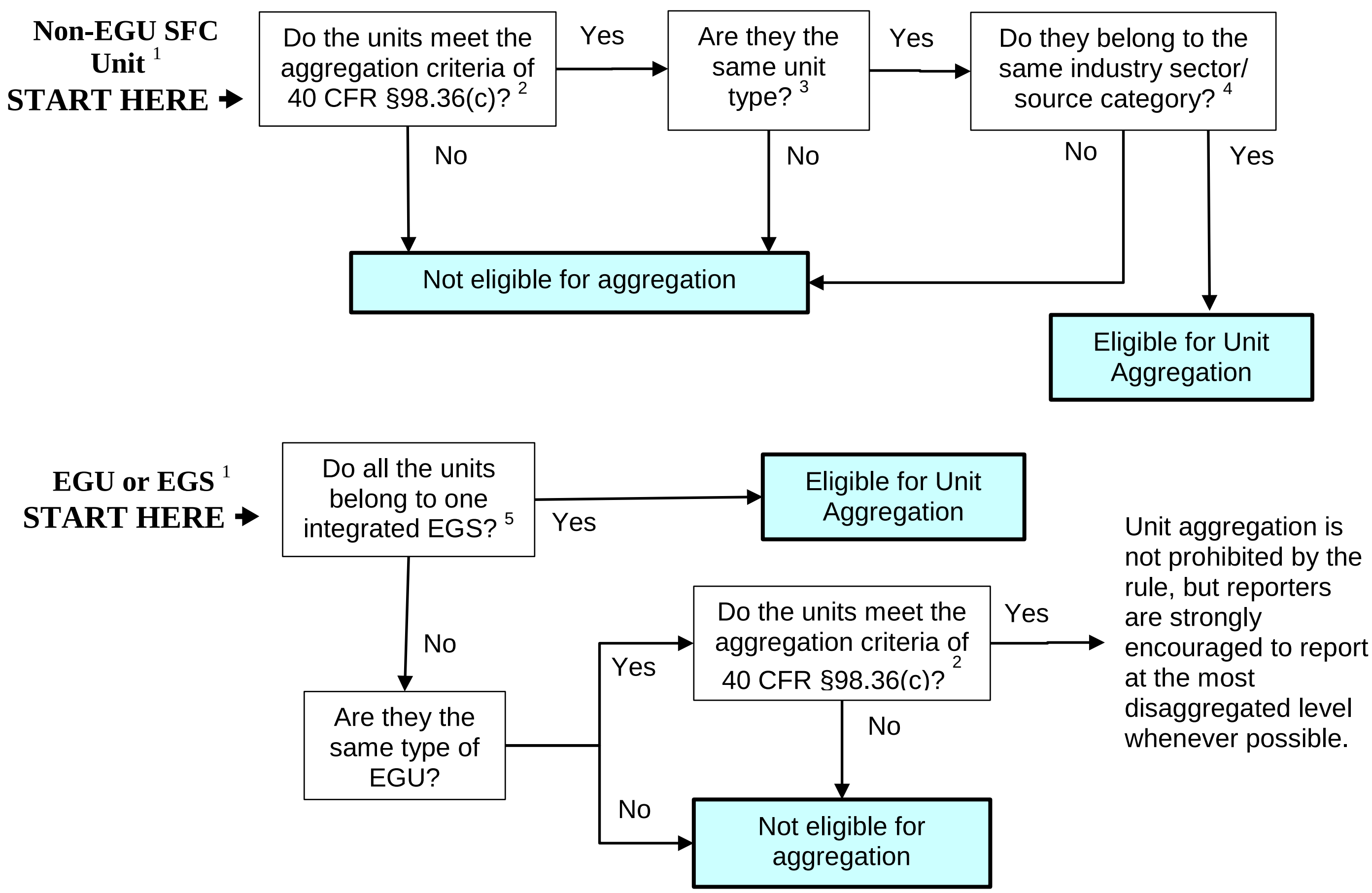
PERCENT OF FUEL GROUPED INTO THIS CONFIGURATION ATTRIBUTED TO EACH UNIT TYPE (If more than one unit type is aggregated into the group, the reporter is required to provide the following information (§95115(h))

Fuel (pull-down menu)	Type of Unit (pull-down menu)	Percent of Fuel*
Natural gas	Boiler	60 %
Natural gas	Heater	40 %

*The percent of fuel must add up to 100% for each fuel type.

Alternatively, the reporter may replace the existing configuration with 2 new configurations, one for the two boilers, and another for the 10 heaters. Also, as required by the rule, reporters need to provide a description of the aggregated units in the unit description of the configuration. Note that EGU and EGS are always treated differently from other stationary fuel combustion sources. By reporting disaggregated fuel information at the unit type level in compliance with the amended unit aggregation rule language, the reporter meets the rule requirements for unit aggregation.

Figure 1. Determine Eligibility for Unit Aggregation



[1] Before beginning the eligibility determination, separate the non-EGU stationary fuel combustion units, Part 75 EGU, non-Part-75 EGU, and process emission sources. Aggregation across these four broad categories is not allowed.

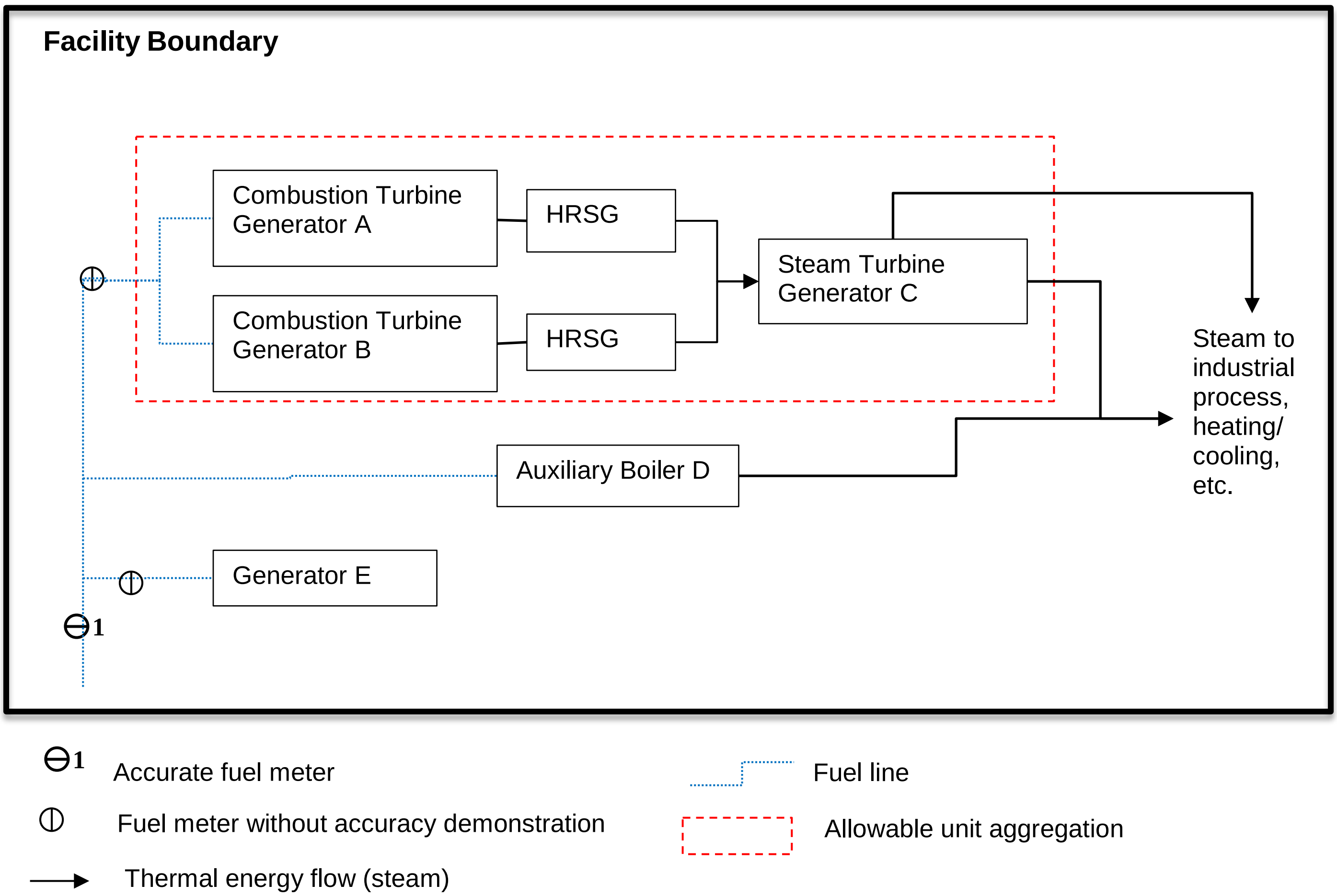
[2] If 40 CFR §98.36(c)(2)- *Monitored common stack or duct configuration* applies and is used by facility operators to report aggregated units, the facility operator may report the aggregated group as a "common stack" configuration in the reporting tool per 40 CFR 98.36(c)(2), but they need to separately report the fuel heat input of individual units or group of units using the same aggregation criteria specified in the MRR.

[3] Unit types are: boiler, reciprocating internal combustion engine (RICE), turbine, process heater, and other (none of the above).

[4] Industry sector or source category is defined in section 95101(a)(1)(A)-(B) of the MRR and 40 CFR Part 98 Tables A-3, A-4, A-5.

[5] EGS types are: cogeneration system, bigeneration system, combined cycle electricity generation system, and system with boils producing steam to feed steam turbine generators. Different types of systems cannot be aggregated. A standby/auxiliary boiler that does not contribute to electricity generation is not considered a part of the cogeneration system.

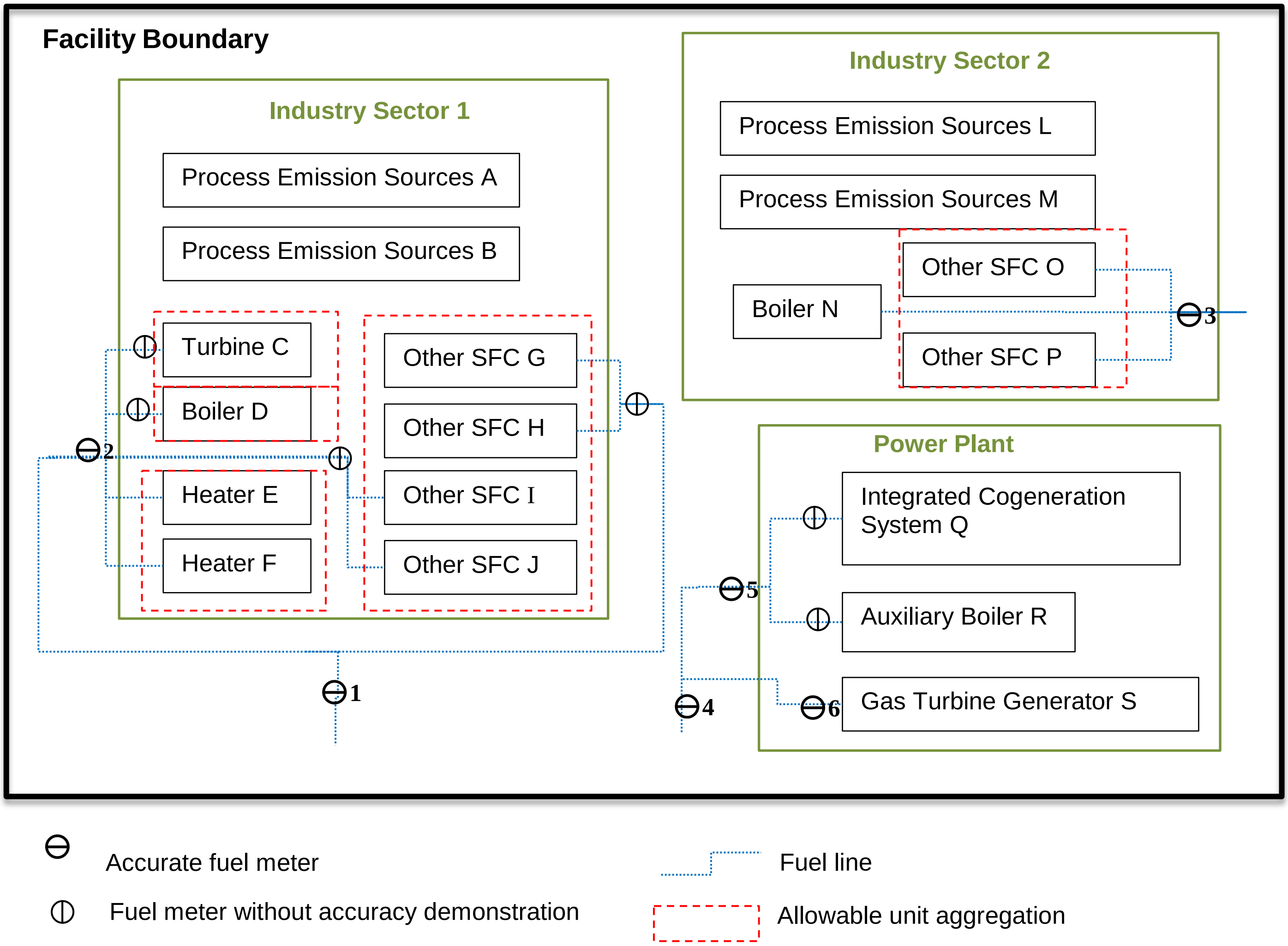
Unit Aggregation Example 1: A Power Plant



In this example, the power plant includes a cogeneration system, an auxiliary boiler, and a separate gas turbine generator. Combustion Turbine Generator A, Combustion Turbine Generator B, the two heat recovery steam generators (HRSGs), and Steam Turbine Generator C are all integral parts of the cogeneration system; therefore, they may be aggregated into a system. Because Auxiliary Boiler D does not contribute to electricity generation, it cannot be aggregated with the cogeneration system. (Aggregating the auxiliary boiler with the cogeneration system in this case would make the cogeneration system appear less efficient when accounting for the energy balance of the system.) However, if this system is configured slightly differently in an alternative scenario such that the steam from Auxiliary Boiler D feeds into Steam Turbine Generator C, then the boiler is considered a part of the cogeneration system because it contributes to electricity generation. Generator E cannot be aggregated with the cogeneration system, because it is a different EGU type; and it cannot be aggregated with the Auxiliary Boiler D, because an EGU cannot be aggregated with a non-EGU SFC unit.

Meter No. 1 (⊖1) is the only meter that meets the calibration and accuracy requirements of the regulation. The facility operator has not demonstrated accuracy of the meters at A and B and the meter at E, and there is no meter at the auxiliary boiler. Although facility operators are encouraged to maintain accurate meters at higher and lower levels, in this case they may use engineering estimation when reporting fuel consumption quantities at the cogeneration system, Auxiliary Boiler D, and Generator E. If the operators believe that the downstream meters at A+B and E are in proper function despite lacking accuracy demonstration, they may use those downstream meters to report fuel use quantities of the cogeneration system and Generator E. The operator must be able to demonstrate to the verifier that the chosen engineering estimation method is reasonable and is expected to produce reasonably accurate results. Also, the estimated fuel consumption quantities at the lower level must add up to the accurate upstream total at Meter No. 1.

Unit Aggregation Example 2: A Facility Consists of Multiple Industry Sectors



In this example, there are two different industry sectors (e.g., petroleum refining operation and hydrogen production operations) and a power plant within the same facility boundary. Although reporters are encouraged to report at the most disaggregated level whenever possible, they may choose to aggregate the units if they meet the unit aggregation criteria.

Heater E and Heater F may be aggregated because they belong to the same unit type and same industry sector operation. Boiler D, Boiler N, and Auxiliary Boiler R cannot be aggregated because they belong to different industry sector operations, despite all being boilers. Other SFC sources G, H, I, and J may be aggregated because they are SFC units that are not a boiler, RICE, turbine, or process heater; and they are all associated with the same industry sector operation. They fall into the "other (none of the above)" unit type category. However, the facility operator may or may not want to aggregate all of the "other SFC" units if aggregation makes the facility emissions inventory more difficult to verify and more difficult to cross check with other emission reporting programs. Operators should make an informed decision about unit aggregation with verification and inventory tracking in mind.

An example scenario: In the previous year, the facility operator had reported Turbine C, Boiler D, Heater E, Heater F, Other SFC G, Other SFC H, Other SFC I, and Other SFC J together in one aggregated-units configuration in the reporting tool, and used Meter No. 2 (⊖**2**) for reporting fuel consumption and emissions. The operator would like to maintain the existing configuration, instead of replacing it with four new configurations (Turbine C unit, Boiler D unit, Heaters E&F group, and Other SFC group). The operator may keep the existing configuration, but is required to provide disaggregated information in a new table within the configuration in the tool. The table might look like below:

PERCENT OF FUEL GROUPED INTO THIS CONFIGURATION ATTRIBUTED TO EACH UNIT TYPE (If more than one unit type is aggregated into the group, the reporter is required to provide the following information (§95115(h))

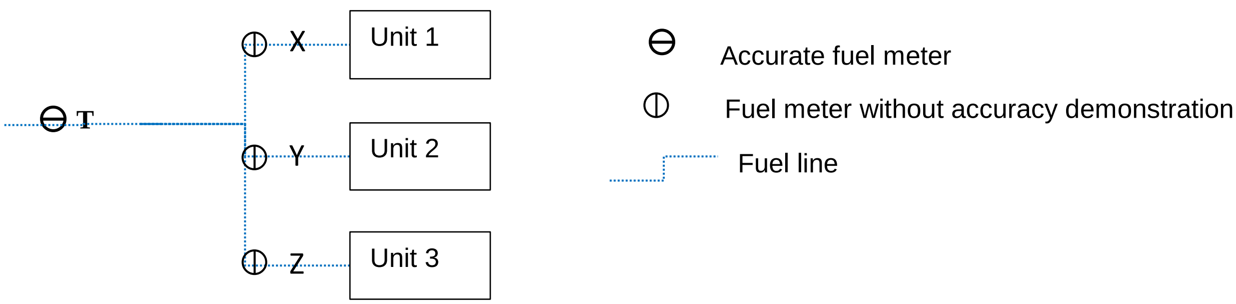
Fuel (pull-down menu)	Type of Unit (pull-down menu)	Percent of Fuel*
Natural gas	Turbine	35 %
Natural gas	Boiler	20 %
Natural gas	Heaters	15 %
Natural gas	Other (none of the above)	30 %

*The percent of fuel must add up to 100% for each fuel type.

In terms of fuel meter accuracy requirements, if the regulation does not otherwise require a fuel meter at a specific unit to be accurate, and the facility operators may trace the fuel quantity to an upstream meter that meets the calibration and accuracy requirements, they may use an engineering estimation when reporting fuel quantities and emissions at the lower-level. (See section 95103(k) of the MRR.)

For example, Turbine C and Boiler D each have a fuel meter without accuracy demonstration. Although facility operators are encouraged to meet calibration and accuracy standard for any meters whenever feasible, they are not required to have accurate meters at Turbine C and Boiler D because the upstream Meter No. 2 (⊖**2**) meets the accuracy standard. For Heater E and Heater F that do not have meters, the facility operator may use a best available method to estimate the fuel use at Heater E and Heater F. The chosen engineering estimation method must be reasonable, and the estimated fuel use quantities must add up to the accurate total at Meter No. 2 or Meter No. 1. Similarly, the operator must report Boiler N separately from Other SFC O and Other SFC P, but they may use engineering estimation to report the fuel use at Boiler N and the aggregated O and P group, as long as the fuel quantities add up to the quantity measured by the accurate Meter No. 3 (⊖**3**).

Unit Aggregation Example 3: Engineering Estimation by Allocating Upstream Fuel Measurement



This example consists of 3 units configured in parallel branches of a common fuel line. Each unit has its own unit-level meter that may or may not meet the accuracy demonstration requirements, but their common fuel meter upstream meets the accuracy requirements. The operator may use the fuel quantities measured by the 3 unit-level meters to allocate the "accurate" upstream total to the 3 units. If the fuel quantities measured by the unit-level meters do not add up to the accurate upstream meter, the operator may allocate the upstream total using the relative proportions of the 3 unit-level quantities. Such an approach is an acceptable engineering estimation method, provided that the verifier is able to confirm that the approach is reasonable and based on good engineering principles given the unique situation at each facility.

An example calculation is provided as follows:

If
T = the total fuel consumption measured by the accurate upstream meter
X = fuel consumption measured by unit 1 meter*
Y = fuel consumption measured by unit 2 meter*
Z = fuel consumption measured by unit 3 meter*

* The meter may or may not have accuracy demonstration.

[X + Y + Z] may or may not add up to $\pm$5% of T.

One of the acceptable ways to do the fuel allocation is:
Fuel consumed by Unit 1 = T*(X/(X+Y+Z))
Fuel consumed by Unit 2 = T*(Y/(X+Y+Z))
Fuel consumed by Unit 3 = T*(Z/(X+Y+Z))