CHAPTER 11: HYDROGEN PLANTS
(Guidance for Regulation Section 95114)

Chapter 11 discusses those portions of the regulation that apply specifically to GHG emissions from hydrogen plants. Many of the reporting requirements for operators of hydrogen production facilities are identical to those for petroleum refiners, so the operator will want to refer to Chapter 10 as needed.

As listed in section 95114(a) of the regulation, the emissions data report for a petroleum refinery must include the following information as applicable:

1. Consumption data for all fuel and feedstocks
2. Hydrogen production
3. Stationary Combustion CH_4 and N_2O emissions
4. Fugitive emissions
5. Flaring emissions
6. Transferred CO and CO_2
7. Process vent emissions
8. Sulfur recovery process emissions
9. Electricity generating unit emissions
10. Cogeneration emissions
11. Indirect energy purchases
12. Stationary combustion and process emissions

Reporting requirements for these items are discussed in more detail below.

11.1 Fuel and Feedstock Consumption

Operators must report the amount of each fuel and feedstock consume annually, in the units specified in section 95114(a)(1). Reporting of feedstock consumption should be limited to feedstock which actually produces GHG emissions. The use of CEMS is permitted for both stationary combustion and process emissions; see section 13.7 of this document. Remember that if you do use a CEMS, you must still report fuel consumption for all fuels and feedstock consumption for all GHG generating feedstocks.

11.2 Hydrogen Production

Operators are required to report the total volume (scf) of hydrogen produced each year and also the amount of hydrogen used as a transportation fuel (scf).

The purpose of this chapter is to provide guidance on the requirements of section 95114 of the mandatory GHG reporting regulation. As described more specifically in Chapter 1 of this document, this guidance does not add to, substitute for, or amend the regulatory requirements as written in these or other sections of the regulation [Subchapter 10, Article 2, sections 95100 to 95133, title 17, California Code of Regulations].

11.3 Stationary Combustion – CH_4 and N_2O

The stationary combustion methane and nitrous oxide calculation methods are found in section 95125(b). See section 10.1.7 of the petroleum refineries chapter for details on the three available methods.

11.4 Fugitive Emissions

Operators are required to report fugitive emissions from the sources covered in section 95113(c) of the regulation – wastewater treatment, oil-water separators, storage tanks, and equipment fugitives. See section 10.5 of the petroleum refineries chapter for the required methods.

11.5 Flaring Emissions

If you operate a flare or destruction device such as an incinerator at your facility, you are required to report GHG emissions as specified in regulation 95113(d). See the discussion in Chapter 10, section 10.6 of the petroleum refineries chapter.

11.6 Transferred CO2 and CO

Operators who sell either CO or CO_2 must report these quantities. Transferred CO2 and CO are tracked separately but are not subtracted from the GHG report at this time.

11.7 Process Vent Emissions

Emissions from process vents where emissions are not captured and reported elsewhere should be reported using the methods found in section 95113(b)(3), as discussed in Chapter 10, section 10.4.2.

11.8 Sulfur Recovery Process Emissions

Operators of sulfur recovery plants report CO_2 process emissions using the method found in 95113(b)(5), discussed in Chapter 10, section 10.4.4.

11.9 Reporting Requirements for Electricity Generation and Cogeneration

If electricity generation or cogeneration occurs at your facility (within the same contiguous boundary and under your operational control), emissions from these activities must be included in your emissions data report. If the electricity generating or cogeneration facility has a nameplate generating capacity of 1 MW or more, and its CO_2 emissions from electricity generating activities trigger the separate reporting threshold of 2,500 metric tonnes, the report must comply with the requirements of regulation sections 95111 and 95112, as applicable.

> *Do you have electricity generation or a cogeneration system on site?*
>
> If your system is at least 1 MW and emitted at least 2.500 MT CO_2 from electricity generation, refer to the methods provided for the electricity generation and cogeneration sectors to calculate GHG emissions from these sources. See Chapters 8 and 9.

Regulation section 95111 includes the electricity generating facility reporting requirements and is described in Chapter 8 of this document, while section 95112 provides the cogeneration system requirements and is covered in Chapter 9. Refer to those sections of the regulation and the associated guidance chapters for more information.

If your electricity generating activities are not large enough to trigger these additional reporting requirements, include these emissions in your facility GHG report as additional stationary sources, with emissions calculated specific to fuel type like your other sources.

The regulation also includes definitions for "cogeneration facility," "cogeneration system," "generating facility," "generating unit," and "electricity generating facility," which may be helpful in evaluating whether these types of activities or units are at the facility.

11.10 Reporting Indirect Energy Usage

If you purchase and consume electricity from a retail provider or a facility that you do not own or operate, you need to report the amount of electricity usage and identify the provider. Similarly, if you purchase and consume steam, heat, and/or cooling from a facility you do not own or operate, you need to report this thermal energy use and identify the provider. The methodologies are found in Chapter 13.

11.11 Stationary Combustion and Process CO2 Emissions

Operators have three options or approaches to measure, calculate and report the stationary combustion and process CO_2 emissions hydrogen plants.

First, you may use a CEMS to quantify CO_2 stationary combustion and process emissions. If you choose to install a CEMS you should consult 40 CFR Part 75 for installation, calibration and operating procedures for your CO_2 CEMS as directed in section 95125(g). You will report your annual CO2 emissions in metric tonnes based on hourly CO_2 mass emissions from your CEMS unit.

The second option is to report CO_2 stationary combustion and process emissions using a fuel and feedstock mass balance approach (section 95114(b)(2)). Here you calculate stationary combustion fuel CO_2 emissions and feedstock CO_2 emissions separately and sum to report fuel + feedstock CO_2 emissions.

Table 11.11a Hydrogen Production Stationary Combustion and Process CO_2 Emissions – Mass Balance

Required Data	*Units/Value*	*Data Source*
Fuel – Stationary Combustion CO_2	metric tonnes/year	operator determined - see below
Process Feedstock CO_2	metric tonnes/year	operator determined - see below

Stationary combustion fuel CO_2 emissions are calculated using the first formula in regulation section 95114(b)(2). This method requires you to measure the carbon content of each fuel that you combust. The frequency with which you make these fuel carbon content measurements is determined by the fuel combusted.

If you combust a mixture of fuels, you have options as to where and how often you make the carbon content measurements based on your sampling configuration and the fuels combusted. For instance, if you combust natural gas mixed with refinery fuel gas and sample at a point after these two fuels are mixed, you must determine the carbon content of the mixture daily, as is required for refinery fuel gas. You would then determine CO_2 combustion emissions for the mixture. However, you may choose to determine the carbon content of each of these fuels prior to mixing. In this case you would need to determine natural gas carbon content monthly and the refinery fuel gas carbon content daily, and then calculate CO_2 emissions for each fuel separately. The one important distinction you should keep in mind, if you choose to use this approach, is that then all fuel stationary combustion emission calculations are required to be based on carbon content.

Table 11.11b Hydrogen Production Fuel Stationary Combustion CO_2 Emissions – Mass Balance

Required Data	*Units/Value*	*Data Source*
F_a fuel a consumption rate – iterative calculation for each fuel	scf or gallons/day	operator determined
CF_a carbon content of fuel a – iterative calculation for each fuel	kg C/scf or gallon fuel	operator determined
CF – carbon to carbon dioxide	3.664	supplied
CF – kg to metric tonnes	0.001	supplied
X – total number of fuels	unitless	operator determined

$$CO_2(\text{Fuel}) = \sum_{1}^{n} \sum_{1}^{x} (F_a * CF_a) * 3.664 * 0.001$$

Next, you calculate your process related CO_2 emissions using the second equation in section 95114(b)(2). Here you are required to measure the carbon content of all feedstock mixtures daily. If you use natural gas as a feedstock component you may measure carbon content on a monthly basis. The same flexibility is available for feedstock in terms of where you sample and how often you measure carbon content. In this case you may need to account for carbon which is emitted and reported elsewhere and the S term in the equation would be used to quantify this carbon stream. For instance, if CO_2 and/or CH_4 originating in the feedstock were diverted as Pressure Swing Adsorption (PSA) off-gas to a flare or into a refinery fuel gas system and quantified and reported elsewhere, you should quantify this stream and report it using the S term. The carbon content and volume of these gases must be accurately measured. The S term is included to avoid double-counting feedstock carbon dioxide emissions.

Table 11.11c Hydrogen Production Feedstock Process CO_2 Emissions – Mass Balance

Required Data	*Units/Value*	*Data Source*
FS_b – feedstock b consumption rate – iterative calculation for each feedstock	scf/day	operator determined
CFb – carbon content of feedstock b – iterative calculation for each feedstock	kg C/scf	operator determined
S – carbon accounted for elsewhere	Kg C/day	operator determined
CF – carbon to carbon dioxide	3.664	supplied
CF – kg to metric tonnes	0.001	supplied

$$CO_2(\text{Feedstock}) = \sum_1^n \sum_1^y \left[(FS_b * CF_b) - S\right] * 3.664 * 0.001$$

$$CO_2(\text{MassBalance}) = CO_2(\text{Fuel}) + CO_2(\text{Feedstock})$$

Finally, you may choose to quantify, calculate and report CO_2 stationary combustion and process CO_2 emissions separately as shown in section 95114(b)(3). In this case, stationary combustion emissions are calculated using the methods found in the refinery section 95113(a)(1). Thus, if you choose this approach you may be able to use default HHV and emission factors for some of your standard fuels.

Process CO_2 emissions are calculated using the formula found in 95114(b)(3). As with the mass balance approach you should calculate feedstock carbon content daily, except for natural gas, for which monthly measurements of carbon content are sufficient if you are not mixing natural gas with other feedstock or are determining the carbon content of mixture components prior to mixing.

If you use this approach, you account for carbon dioxide emissions that are reported elsewhere, using the S term.

Table 11.11d Calculation of Process Emissions

Required Data	*Units/Value*	*Data Source*
FSR_i – feedstock i consumption rate – iterative calculation for each feedstock	scf/day	operator determined
CF_i – carbon content of feedstock i – iterative calculation for each feedstock	kg C/scf	operator determined
S – carbon accounted for elsewhere	kg C/day	operator determined
CF – carbon to carbon dioxide	3.664	supplied
CF – kg to metric tonnes	0.001	supplied

$$CO_2 = \sum_1^n \sum_1^x \left[(FSR_i * CF_i) - S\right] * 3.664 * 0.001$$