2.2.1 *Monitoring Options*

The Part 75 rule generally requires the use of CEMS for units that combust coal or other solid fuel(s). Alternative monitoring approaches, some of which are referred to in the rule as “excepted methods” or “excepted monitoring systems”, may be used for qualifying oil-fired and gas-fired units, and for units that combust very low-sulfur fuel, regardless of the state of matter (solid, liquid, or gas).

Part 75 provides several monitoring options. The options that are available for a unit depend on how the unit is classified (see Table 2, below). In general, if a unit is coal-fired or combusts any type of solid fuel, the basic continuous monitoring provisions in §§75.10-75.18 require the use of CEMS for all monitored parameters. However, if a unit is classified as oil- or gas-fired, or if it combusts “very low sulfur fuel”5, it may qualify for an alternative monitoring approach instead of CEMS for some or all parameters. In some cases, the unit may even qualify for a monitoring exemption.

Table 2: Part 75 Monitoring Options

If an Affected Unit …….	These are the Allowable Monitoring Options…….					
	Basic CEMS Provisions[a] (§§75.10-18)	Appendix D Method[b]	Appendix E Method[c]	LME Method[d] (§75.19)	Appendix G Method[e]	Equation F-23[f]
Is a coal-fired unit under ARP or CAIR	✓				✓	
Is a non-peaking oil-fired or gas-fired unit under ARP or CAIR	✓	✓		✓	✓	
Is an oil-fired or gas-fired peaking unit under ARP or CAIR	✓	✓	✓	✓	✓	
Combusts very low sulfur fuel(s) and is equipped with flow rate and diluent gas monitors	✓					✓

[a] For SO_2, NO_X, CO_2, flow rate, opacity, and heat input (as applicable).
[b] For SO_2 emissions and heat input only.
[c] For NO_X emissions only. If Appendix E is used for NO_x, Appendix D must be used for SO_2 and/or heat input.
[d] If the LME qualifying thresholds are met and this method is selected, it must be used for all parameters, i.e., for SO_2, NO_X, CO_2, and heat input (as applicable)
[e] For CO_2 emissions only
[f] For SO_2 emissions only

The monitoring alternatives or exemptions that apply to a unit depend mainly on how often the unit operates each year, how much it emits, and the type(s) of fuel(s) it combusts. These alternatives and exemptions are:

• ***Any oil-fired or gas-fired unit*** may use the alternative, or “excepted” methodology in Appendix D of Part 75 to determine SO_2 mass emissions and/or unit heat input. The Appendix D method requires continuous monitoring of the fuel flow rate with a certified fuel flowmeter and periodic fuel sampling and analysis to determine one or more of the following quantities: (1) the gross calorific value (GCV) of the fuel; (2) the fuel sulfur content; and (3) the density of the fuel. The Appendix D methodology is discussed in greater detail in Section 4 of this guide.

• ***Oil-fired and gas-fired peaking units*** may use the alternative method in Appendix E of Part 75 to estimate the hourly NO_x emission rate in lb/mmBtu. Appendix E requires hourly determination of the heat input rate to the unit, using the fuel flow rate measured by a certified Appendix D fuel flowmeter, in conjunction with the GCV of the fuel. A correlation curve of NO_x emission rate versus heat input rate (derived from emission testing) is then used to estimate the hourly NO_x emission rates. The Appendix E methodology is discussed in greater detail in Section 5 of this guide.

• ***Certain oil-fired and gas-fired units*** may qualify to use the low mass emissions (LME) methodology in §75.19 to estimate SO_2, CO_2, and/or NO_x emissions and heat input. To qualify for LME status, a unit's annual SO_2 and NO_x mass emissions, and in some cases, its ozone season NO_x mass emissions, must be demonstrated to be below certain threshold values.

The LME methodology requires that records be kept of the hours in which the unit operates, the type(s) of fuel(s) combusted, the electrical or steam load during each of those hours, and, in some cases, the operational status of the NO_x emission controls. Default emission rates and estimates of heat input are used to quantify the unit's mass emissions. The LME methodology is discussed in greater detail in Section 6 of this guide.

• ***Certain units that combust very low sulfur fuel(s)*** may use Equation F-23 in Appendix F of Part 75 to estimate SO_2 emissions, in lieu of using an SO_2 monitor. Equation F-23 uses a fuel-specific default SO_2 emission rate (lb/mmBtu), together with hourly measurements of unit heat input rate (mmBtu/hr), made with a flow monitor and a diluent (CO_2 or O_2) monitor, to determine the hourly SO_2 mass emission rate (lb/hr). This methodology is most useful for coal-fired units that occasionally burn natural gas as a secondary fuel, or for units that combust very low sulfur solid fuels (e.g., wood), either alone or in combination with very low sulfur fossil fuel such as natural gas. To use Equation F-23 for the combustion of non-fossil fuels that meet the definition of "very low sulfur fuel" in 40 CFR 72.2, Administrative approval of a fuel-specific default SO_2 emission rate is required.

• ***Acid Rain Program and RGGI units*** may use the alternative procedures in Appendix G of Part 75 to estimate CO_2 mass emissions, in lieu of installing CEMS. Appendix G provides two basic methods for determining CO_2 emissions: (1) daily CO_2 emissions are calculated from company records of fuel usage and the results of periodic fuel sampling and analysis (to determine the % carbon in the fuel); and (2) hourly CO_2 emissions are calculated using heat input rate measurements made with certified Appendix D fuel flowmeters together with fuel-specific, carbon-based "F-factors". Note that although the model rule for the RGGI program prohibits the use of Option (1), three States (Maine, Maryland and Delaware) have decided to deviate from the model rule and allow Option (1), with enhanced reporting.

Appendix G is the most frequently-used method for estimating CO_2 mass emissions from oil and gas-fired units. Part 75 allows the fuel feed rate methodology (Option (1), above) to be used for coal-fired units also, but it is not currently being used by any of them.

• ***Certain Acid Rain Program units*** may be exempted from opacity monitoring requirements. First, coal-fired units with wet scrubbers may be exempted, if it is demonstrated that the presence of condensed water in the effluent gas stream interferes with the opacity readings. Second, any unit that meets the definition of gas-fired or diesel-fired in §72.2, or that qualifies as a dual-fuel reciprocating engine is exempted from opacity monitoring. Third, a unit with a certified continuous particulate matter (PM) monitoring system is exempted from opacity monitoring. However, note that these Part 75 exemptions do not supersede the provisions of any other program, regulation, or permit that may require an opacity monitor to be installed.

Sections 3 through 6 of this guide provide more information on the various Part 75 emission monitoring methodologies. Section 3 describes the basic CEM provisions, and Sections 4, 5, and 6, respectively, discuss the alternative Appendix D, Appendix E, and Low Mass Emissions methodologies.