Industrial Boiler MACT Reconsideration Rule Requirements Summary

Federal Regulation:

- NESHAP 40 CFR 63 Subpart DDDDD
- Proposed rule published 6/4/2010
- Final rule published 3/21/2011, reconsidered 5/18/2011
- Re-proposal published 12/23/2011
- Final rule signed 12/20/2012
- Info at http://epa.gov/airquality/combustion/actions.html

Affected Source:

- The affected source is: (1) the collection at a major source of all existing industrial, commercial, and institutional boilers and process heaters within a subcategory as defined in §63.7575 or (2) each new or reconstructed industrial, commercial, or institutional boiler or process heater, as defined in §63.7575, located at a major source.
- A boiler or process heater is new if you commence construction of the boiler or process heater after June 4, 2010, and you meet the applicability criteria at the time you commence construction.
- The affected source does not include boilers and process heaters that are subject to another standard under 40 CFR 63 or a standard established under CAA section 129.
- An existing EGU that meets the applicability requirements of this rule after the effective date of the final rule due to a change (e.g., fuel switch) is an existing source under this rule.

Exemptions:

- An electric utility steam generating unit covered by 40 CFR 63, Subpart UUUUU.
- A recovery boiler or furnace covered by 40 CFR 63, subpart MM.
- A boiler or process heater that is used specifically for research and development, including test steam boilers used to provide steam for testing the propulsion systems on military vessels. This does not include units that provide heat or steam to a process at a research and development facility.
- A hot water heater (≤120 gal, <160 psig pressure, <210°F).
- A refining kettle covered by 40 CFR 63, subpart X.
- An ethylene cracking furnace covered by 40 CFR 63, subpart YY.
- Blast furnace stoves.
- Any boiler or process heater specifically listed as an affected source in another standard(s) under 40 CFR part 63, such as boilers and process heaters used as control devices to comply with subparts JJJ, OOO, PPP, and U.
- Any boiler or process heater that is used as a control device to comply with another subpart under Part 60, 61, or 63, provided that at least 50 percent of the average annual heat input to the boiler or process heater during any 3 consecutive calendar years is provided by the gas stream that is regulated under another subpart.
- Temporary boilers (onsite less than 180 consecutive days).
- Blast furnace gas fuel-fired boilers and process heaters.
- Any boiler specifically listed as an affected source in a Section 129 standard.
- A unit burning hazardous waste covered by Subpart EEE.
- Residential boilers.

Compliance Dates:

- The initial compliance date for existing units is 3 years from publication of the final rule in the Federal Register (expected Jan or Feb 2013). Sources may request an additional year to comply from the permitting agency if they are installing controls or repowering.
- New sources must comply with the rule upon startup, but since the rule has changed several times, new sources have a period of 3 years from publication of the final rule to comply with alternate limits before they must comply with the finalized new source limits.
    - If your boiler or process heater commenced construction or reconstruction after June 4, 2010 and before May 20, 2011, you may comply with the emission limits in Table 1 (final new source limits) or 11 (alternate new source limits).
    - If your boiler or process heater commenced construction or reconstruction after May 20, 2011 and before December 23, 2011, you may comply with the emission limits in Table 1 (final new source limits) or 12 (alternate new source limits).
    - If your boiler or process heater commenced construction or reconstruction after December 23, 2011 and before [DATE OF PUBLICATION OF FINAL RULE IN THE FEDERAL REGISTER], you may comply with the emission limits in Table 1 (final new source limits) or 13 (alternate new source limits).

Subcategories:

1. Pulverized coal/solid fossil fuel units.
2. Stokers designed to burn coal/solid fossil fuel.
3. Fluidized bed units designed to burn coal/solid fossil fuel.
4. Fluidized bed units with FB heat exchanger designed to burn coal/solid fossil fuel.
5. Stokers/sloped grate/other units designed to burn wet biomass/bio-based solid fuel.
6. Stokers/sloped grate/other units designed to burn kiln-dried biomass/bio-based solid fuel.
7. Fluidized bed units designed to burn biomass/bio-based solid fuel.
8. Suspension burners designed to burn biomass/bio-based solid fuel
9. Dutch Ovens/pile burners designed to burn biomass/bio-based solid.
10. Fuel Cells designed to burn biomass/bio-based solid fuel.
11. Hybrid suspension/grate burners designed to burn biomass/bio-based solid fuel.
12. Units designed to burn solid fuel.
13. Units designed to burn coal/solid fossil fuel.
14. Units designed to burn liquid fuel.
15. Units designed to burn light liquid fuel.
16. Units designed to burn heavy liquid fuel.
17. Units designed to burn liquid fuel in non-continental States or territories.
18. Units designed to burn natural gas, refinery gas or other gas 1 fuels.
19. Units designed to burn gas 2 (other) gases.
20. Metal process furnaces.
21. Limited-use boilers and process heaters.

- For the fuel based HAP (mercury/HCl), if your new or existing unit combusts at least 10 percent solid fuel on an annual basis, your unit is subject to emission limits that are based on data from all of the solid fuel-fired combustor designs.
- If your new or existing boiler or process heater burns at least 10 percent biomass on an annual average heat input basis, the unit is in one of the biomass subcategories for PM/TSM and CO.
- If your new or existing boiler or process heater burns at least 10 percent coal, on an annual average heat input basis, and less than 10 percent biomass, on an annual

average heat input basis, the unit is in one of the coal subcategories for PM/TSM and CO.

- If your new or existing boiler or process heater burns at least 10 percent heavy liquid fuel, and less than 10 percent coal and less than 10 percent biomass, on an annual heat input basis, the unit is in the heavy liquid subcategory.
- If your new or existing boiler or process heater burns light liquid fuel (e.g., distillate oil, biodiesel, or vegetable oil), and less than 10 percent coal and less than 10 percent biomass, on an annual heat input basis, and the unit is not in the heavy liquid subcategory, the unit is in the light liquid subcategory.
- If your facility is located outside of the 48 contiguous states or Alaska and your new or existing unit combusts at least 10 percent liquid fuel and less than 10 percent solid fuel, your unit is subject to the non-continental liquid fuel emission limits.
- If your unit combusts gaseous fuel that does not qualify as a Gas 1 fuel and no liquid fuel, your unit is subject to the Gas 2 emission limits.
- If your unit combusts only natural gas, refinery gas, or equivalent fuel (other gas that qualifies as Gas 1 fuel), with limited exceptions for gas curtailment and emergencies, your unit is subject to a work practice standard that requires an annual tune-up in lieu of emission limits.
- If your unit is a limited use unit (any boiler or process heater that burns any amount of solid, liquid, or gaseous fuels and has a federally enforceable average annual capacity factor of no more than 10 percent) you are not subject to the emission limits, operating limits, or energy assessment requirements. Limited use units must complete a tune-up every 5 years.

Important Definitions:

- Biomass or bio-based solid fuel means any biomass-based solid fuel that is not a solid waste. This includes, but is not limited to, wood residue; wood products (e.g., trees, tree stumps, tree limbs, bark, lumber, sawdust, sander dust, chips, scraps, slabs, millings, and shavings); animal manure, including litter and other bedding materials; vegetative agricultural and silvicultural materials, such as logging residues (slash), nut and grain hulls and chaff (e.g., almond, walnut, peanut, rice, and wheat), bagasse, orchard prunings, corn stalks, coffee bean hulls and grounds. This definition of biomass is not intended to suggest that these materials are or are not solid waste.

- Boiler means an enclosed device using controlled flame combustion and having the primary purpose of recovering thermal energy in the form of steam or hot water. Controlled flame combustion refers to a steady-state, or near steady-state, process wherein fuel and/or oxidizer feed rates are controlled. A device combusting solid waste, as defined in §241.3 of this chapter, is not a boiler unless the device is exempt from the definition of a solid waste incineration unit as provided in section 129(g)(1) of the Clean Air Act. Waste heat boilers are excluded from this definition.

- Coal means all solid fuels classifiable as anthracite, bituminous, sub-bituminous, or lignite by ASTM D388 (incorporated by reference, see §63.14), coal refuse, and petroleum coke. For the purposes of this subpart, this definition of “coal” includes synthetic fuels derived from coal, including but not limited to, solvent-refined coal, coal-oil mixtures, and coal-water mixtures. Coal derived gases are excluded from this definition.

- Electric utility steam generating unit means a fossil fuel-fired combustion unit of more than 25 megawatts electric (MWe) that serves a generator that produces electricity for sale. A fossil fuel-fired unit that cogenerates steam and electricity and supplies more than one-third of its potential electric output capacity and more than 25 MWe output to any utility power distribution system for sale is considered an electric utility steam generating unit. To be "capable of combusting" fossil fuels, an EGU would need to have these fuels allowed in their operating permits and have the appropriate fuel handling facilities on-site or otherwise available (e.g., coal handling equipment, including coal storage area, belts and conveyers, pulverizers, etc.; oil storage facilities). In addition, fossil fuel-fired EGU means any EGU that fired fossil fuel for more than 10.0 percent of the average annual heat input in any 3 consecutive calendar years or for more than 15.0 percent of the annual heat input during any one calendar year after April 16, 2012.

- Gaseous fuel includes, but is not limited to, natural gas, process gas, landfill gas, coal derived gas, refinery gas, and biogas. Blast furnace gas and process gases that are regulated under another subpart of this part, or part 60, part 61, or part 65 of this chapter, are exempted from this definition.
- Heavy Liquid includes residual oil and any other liquid fuel not classified as a light liquid.
- Hot water heater means a closed vessel with a capacity of no more than 120 U.S. gallons in which water is heated by combustion of gaseous, liquid, or biomass/bio-based solid fuel and is withdrawn for use external to the vessel. Hot water boilers (i.e., not generating steam) combusting gaseous, liquid, or biomass fuel with a heat input capacity of less than 1.6 million Btu per hour are included in this definition. The 120 U.S. gallon capacity threshold to be considered a hot water heater is independent of the 1.6 MMBtu/hr heat input capacity threshold for hot water boilers. Hot water heater also means a tankless unit that provides on demand hot water.
- Light Liquid includes distillate oil, biodiesel or vegetable oil.
- Liquid fuel includes, but is not limited to, light liquid, heavy liquid, any form of liquid fuel derived from petroleum, used oil, liquid biofuels, biodiesel, vegetable oil, and comparable fuels as defined under 40 CFR 261.38.
- Limited-use boiler or process heater means any boiler or process heater that burns any amount of solid, liquid, or gaseous fuels and has a federally enforceable average annual capacity factor of no more than 10 percent.
- Metal process furnaces are a subcategory of process heaters, as defined in this subpart, which include natural gasfired annealing furnaces, preheat furnaces, reheat furnaces, aging furnaces, heat treat furnaces, and homogenizing furnaces.
- Natural gas means (1) A naturally occurring mixture of hydrocarbon and nonhydrocarbon gases found in geologic formations beneath the earth's surface, of which the principal constituent is methane; or (2) Liquefied petroleum gas, as defined in ASTM D1835 (incorporated by reference, see §63.14); or (3) A mixture of hydrocarbons that maintains a gaseous state at ISO conditions. Additionally, natural gas must either be composed of at least 70 percent methane by volume or have a gross calorific value between 35 and 41 megajoules (MJ) per dry standard cubic meter (950 and 1,100 Btu per dry standard cubic foot); or (4) Propane or propane derived synthetic natural gas. Propane means a colorless gas derived from petroleum and natural gas, with the molecular structure C3H8.
- Oxygen trim system means a system of monitors that is used to maintain excess air at the desired level in a combustion device. A typical system consists of a flue gas oxygen and/or CO monitor that automatically provides a feedback signal to the combustion air controller.
- Period of gas curtailment or supply interruption means a period of time during which the supply of gaseous fuel to an affected boiler or process heater is restricted or halted for reasons beyond the control of the facility. The act of entering into a contractual

agreement with a supplier of natural gas established for curtailment purposes does not constitute a reason that is under the control of a facility for the purposes of this definition. An increase in the cost or unit price of natural gas due to normal market fluctuations not during periods of supplier delivery restriction does not constitute a period of natural gas curtailment or supply interruption. On-site gaseous fuel system emergencies or equipment failures qualify as periods of supply interruption when the emergency or failure is beyond the control of the facility.

- Process heater means an enclosed device using controlled flame, and the unit's primary purpose is to transfer heat indirectly to a process material (liquid, gas, or solid) or to a heat transfer material (e.g., glycol or a mixture of glycol and water) for use in a process unit, instead of generating steam. Process heaters are devices in which the combustion gases do not come into direct contact with process materials. A device combusting solid waste, as defined in §241.3 of this chapter, is not a process heater unless the device is exempt from the definition of a solid waste incineration unit as provided in section 129(g)(1) of the Clean Air Act. Process heaters do not include units used for comfort heat or space heat, food preparation for on-site consumption, or autoclaves. Waste heat process heaters are excluded from this definition.
- Refinery gas means any gas that is generated at a petroleum refinery and is combusted. Refinery gas includes natural gas when the natural gas is combined and combusted in any proportion with a gas generated at a refinery. Refinery gas includes gases generated from other facilities when that gas is combined and combusted in any proportion with gas generated at a refinery.
- Residential boiler means a boiler used to provide heat and/or hot water and/or as part of a residential combined heat and power system. This definition includes boilers located at an institutional facility (e.g., university campus, military base, church grounds) or commercial/industrial facility (e.g., farm)used primarily to provide heat and/or hot water for:(1) A dwelling containing four or fewer families; or (2) A single unit residence dwelling that has since been converted or subdivided into condominiums or apartments.
- Shutdown means the cessation of operation of a boiler or process heater for any purpose. Shutdown begins either when none of the steam from the boiler is supplied for heating and/or producing electricity, or for any other purpose, or at the point of no fuel being fired in the boiler or process heater, whichever is earlier. Shutdown ends when there is no steam and no heat being supplied and no fuel being fired in the boiler or process heater.
- Startup means either the first-ever firing of fuel in a boiler or process heater for the purpose of supplying steam or heat for heating and/or producing electricity, or for any other purpose, or the firing of fuel in a boiler after a shutdown event for any purpose. Startup ends when any of the steam or heat from the boiler or process heater is supplied for heating, and/or producing electricity, or for any other purpose.
- Temporary boiler means any gaseous or liquid fuel boiler that is designed to, and is capable of, being carried or moved from one location to another by means of, for example, wheels, skids, carrying handles, dollies, trailers, or platforms. A boiler is not a temporary boiler if any one of the following conditions exists:
    - The equipment is attached to a foundation.
    - The boiler or a replacement remains at a location within the facility and performs the same or similar function for more than 12 consecutive months, unless the regulatory agency approves an extension. An extension may be granted by the regulating agency upon petition by the owner or operator of a unit specifying the basis for such a request. Any temporary boiler that replaces a temporary boiler

at a location and performs the same or similar function will be included in calculating the consecutive time period.
  - The equipment is located at a seasonal facility and operates during the full annual operating period of the seasonal facility, remains at the facility for at least 2 years, and operates at that facility for at least 3 months each year.
  - The equipment is moved from one location to another within the facility but continues to perform the same or similar function and serve the same electricity, steam, and/or hot water system in an attempt to circumvent the residence time requirements of this definition.

- Total selected metals means the combination of the following metallic hazardous air pollutants: arsenic, beryllium, cadmium, chromium, lead, manganese, nickel and selenium.

Emissions Limits and Work Practices:

Emission limits were developed for new and existing sources for 16 subcategories, which EPA developed based on unit design.

- Fuel based emission limits for HCl, Hg
- Fuel and boiler design based limits for PM/TSM and CO

Limits for existing sources are based on top 12% of units for which EPA has data in subcategories with population greater than or equal to 30 units, and top 5 units in subcategories with population less than 30 units. Limits for new sources are based on the top performing unit in each subcategory. Variability was taken into account using a 99 percent upper prediction level and a fuel content variability adjustment for mercury and chloride.

Emissions averaging is allowed for existing affected sources in the same subcategory for PM (or TSM), HCl, and Hg (even if using CEMS or PM CPMS), but the average emissions have to be within 90 percent of the allowable emissions. Facilities using this approach cannot increase emissions over emission levels achieved upon the effective date of the rule or begin using a less effective control technology than the technology that was in place upon the effective date of the rule.

HAP/Fuel	Mar 2011 Final	Dec 2012 Final	Mar 2011 Final	Dec 2012 Final	Units	Output Based (lb/MMBtu steam output) Dec 2012 Final	
	Existing Boilers		New Boilers			Existing	New
Hg Biomass	4.6	5.7	3.5	0.8	lb/TBtu	6.40E-06	8.70E-07
PM Biomass	0.039	multiple	0.0011	multiple	lb/MMBtu	multiple	multiple
HCl Biomass	0.035	0.022	0.0022	0.022	lb/MMBtu	0.025	0.025
Hg Coal	4.6	5.7	3.5	0.8	lb/TBtu	6.40E-06	8.70E-07
PM Coal	0.039	multiple	0.0011	multiple	lb/MMBtu	multiple	multiple
HCl Coal	0.035	0.022	0.0022	0.022	lb/MMBtu	0.025	0.025
Hg Oil	3.5	2.0	0.21	0.48	lb/TBtu	2.50E-06	5.30E-07
Hg Oil non-continental	0.78	2.0	0.78	0.48	lb/TBtu	2.50E-06	5.30E-07
PM Oil	0.0075	multiple	0.0013	multiple	lb/MMBtu	multiple	multiple
HCl Oil	0.00033	0.0011	0.0032	0.00044	lb/MMBtu	0.0014	0.00048

HAP/Fuel	**Mar 2011 Final**	**Dec 2012 Final**	**Mar 2011 Final**	**Dec 2012 Final**	**Units**	**Output Based (lb/MMBtu steam output) Dec 2012 Final**	
	Existing Boilers		**New Boilers**			**Existing**	**New**
Hg Gas 2	13	7.9	7.9	7.9	lb/TBtu	1.40E-05	1.40E-05
PM Gas 2	0.043	0.0067	0.0067	0.0067	lb/MMBtu	0.012	0.012
HCl Gas 2	0.0017	0.0017	0.0017	0.0017	lb/MMBtu	0.0029	0.0029
Or clean gas 2 can opt in to Gas 1 work practice if prior to combustion:	Hg content <40 μg/m^3 H_2S content <4ppmv	Hg content <40 μg/m^3	Hg content <40 μg/m^3 H_2S content <4ppmv	Hg content <40 μg/m^3	-	NA	NA
Short Term CO Limits							
CO Biomass Wet Stoker/Sloped Grate/Other	490	1500	160	620	ppm at 3%O2	1.4	0.58
CO Biomass Kiln-Dried Stoker/Sloped Grate/Other	490	460	160	460	ppm at 3%O2	0.42	0.42
CO Biomass FB	430	470	260	230	ppm at 3%O2	0.46	0.22
CO Biomass Dutch/Pile	470	770	470	330	ppm at 3%O2	0.84	0.35
CO Biomass Suspension Burner	470	2400	NA	2400	ppm at 3%O2	1.9	1.9
CO Biomass Fuel Cell	690	1100	470	910	ppm at 3%O2	2.4	1.1
CO Biomass Hybrid Suspension/ Grate	3500	2800	1500	1100	ppm at 3%O2	2.8	1.4
CO Coal pulverized	160	130	12	130	ppm at 3%O2	0.11	0.11
CO Coal stoker	270	160	6	130	ppm at 3%O2	0.14	0.12
CO Coal FB	82	130	18	130	ppm at 3%O2	0.12	0.11
CO Coal FBHE	NA	140	NA	140	ppm at 3%O2	0.13	0.12
CO Oil - Heavy	10	130	3	130	ppm at 3%O2	0.13	0.13
CO Oil - Light	10	130	3	130	ppm at 3%O2	0.13	0.13
CO Oil non-continental	160	130	51	130	ppm at 3%O2	0.13	0.13
CO Gas2	9	130	3	130	ppm at 3%O2	0.16	0.16
Long-term CO CEMS-Based Limits					30-day avg unless noted		
CO Biomass Wet Stoker/Sloped Grate/Other	NA	720	NA	390	ppm at 3%O2		
CO Biomass Kiln-Dried Stoker/Sloped Grate/Other	NA	NA	NA	NA	NA		

HAP/Fuel	Mar 2011 Final	Dec 2012 Final	Mar 2011 Final	Dec 2012 Final	Units	Output Based (lb/MMBtu steam output) Dec 2012 Final	
	Existing Boilers		New Boilers			Existing	New
CO Biomass FB	NA	310	NA	310	ppm at 3%O2		
CO Biomass Dutch/Pile	NA	520 (10 day)	NA	520 (10 day)	ppm at 3%O2		
CO Biomass Suspension Burner	NA	2000 (10 day)	NA	2000 (10 day)	ppm at 3%O2		
CO Biomass Fuel Cell	NA	NA	NA	NA	ppm at 3%O2		
CO Biomass Hybrid Suspension/ Grate	NA	900	NA	900	ppm at 3%O2		
CO Coal pulverized	NA	320	NA	320	ppm at 3%O2		
CO Coal stoker	NA	340	NA	340	ppm at 3%O2		
CO Coal FB	NA	230	NA	230	ppm at 3%O2		
CO Coal FBHE	NA	150	NA	150	ppm at 3%O2		
CO Oil - Heavy	NA	NA	NA	NA	NA		
CO Oil - Light	NA	NA	NA	NA	NA		
CO Oil non-continental	NA	NA	NA	NA	NA		
PM Biomass Wet Stoker/Sloped Grate/Other	0.039	0.037	0.001	0.03	lb/MMBtu	0.043	0.035
PM Biomass Kiln-Dried Stoker/Sloped Grate/Other	0.039	0.32	0.001	0.03	lb/MMBtu	0.37	0.035
PM Biomass FB	0.039	0.11	0.001	0.0098	lb/MMBtu	0.14	0.012
PM Biomass Dutch/Pile	0.039	0.28	0.001	0.0032	lb/MMBtu	0.39	0.0043
PM Biomass Suspension Burner	0.039	0.051	0.001	0.051	lb/MMBtu	0.052	0.031
PM Biomass Fuel Cell	0.039	0.020	0.001	0.02	lb/MMBtu	0.055	0.03
PM Biomass Hybrid Suspension/ Grate	0.039	0.44	0.001	0.026	lb/MMBtu	0.55	0.033
PM Coal pulverized	0.039	0.040	0.001	0.0011	lb/MMBtu	0.042	0.0011
PM Coal stoker	0.039	0.040	0.001	0.0011	lb/MMBtu	0.042	0.0011
PM Coal FB	0.039	0.040	0.001	0.0011	lb/MMBtu	0.042	0.0011

HAP/Fuel	Mar 2011 Final	Dec 2012 Final	Mar 2011 Final	Dec 2012 Final	Units	Output Based (lb/MMBtu steam output) Dec 2012 Final	
	Existing Boilers		New Boilers			Existing	New
PM Oil - heavy	0.0075	0.062	0.0013	0.013	lb/MMBtu	0.075	0.015
PM Oil - light	0.0075	0.0079	0.0013	0.0011	lb/MMBtu	0.0096	0.0012
PM Oil non-continental	0.0075	0.27	0.0013	0.023	lb/MMBtu	0.33	0.025
Alternate TSM Limits	2004 rule		2004 rule				
TSM Biomass Wet Stoker/Sloped Grate/Other	0.001	2.4E-04	0.0003	2.6E-05	lb/MMBtu	2.8E-04	2.7E-05
TSM Biomass Kiln-Dried Stoker/Sloped Grate/Other	0.001	4.0E-03	0.0003	4.0E-03	lb/MMBtu	4.6E-03	4.2E-03
TSM Biomass FB	0.001	1.2E-03	0.0003	8.3E-05	lb/MMBtu	1.5E-03	1.1E-04
TSM Biomass Dutch/Pile	0.001	2.0E-03	0.0003	3.9E-05	lb/MMBtu	2.8E-03	5.2E-05
TSM Biomass Suspension Burner	0.001	6.5E-03	0.0003	6.5E-03	lb/MMBtu	6.6E-02	6.6E-03
TSM Biomass Fuel Cell	0.001	5.8E-03	0.0003	2.9E-05	lb/MMBtu	1.6E-02	5.1E-05
TSM Biomass Hybrid Suspension/ Grate	0.001	4.5E-04	0.0003	4.4E-04	lb/MMBtu	5.7E-04	5.5E-04
TSM Coal pulverized	0.001	5.3E-05	0.0003	2.3E-05	lb/MMBtu	5.6E-05	2.7E-05
TSM Coal stoker	0.001	5.3E-05	0.0003	2.3E-05	lb/MMBtu	5.6E-05	2.7E-05
TSM Coal FB	0.001	5.3E-05	0.0003	2.3E-05	lb/MMBtu	5.6E-05	2.7E-05
TSM Oil - heavy	NA	2.0E-04	NA	7.5E-05	lb/MMBtu	2.5E-04	8.2E-05
TSM Oil - light	NA	6.2E-05	NA	2.9E-05	lb/MMBtu	7.5E-04	3.2E-05
TSM Oil non-continental	NA	8.6E-04	NA	8.6E-04	lb/MMBtu	1.1E-03	9.4E-04
TSM Gas 2	NA	2.1E-04	NA	2.1E-04	lb/MMBtu	3.5E-04	3.5E-04
D/F Biomass stoker	0.005	Tune-up	0.005	Tune-up	ng/dscm at 7%O2	Tune-up	Tune-up
D/F Biomass FB	0.02	Tune-up	0.02	Tune-up	ng/dscm at 7%O2	Tune-up	Tune-up
D/F Biomass Dutch/ Suspension	0.2	Tune-up	0.2	Tune-up	ng/dscm at 7%O2	Tune-up	Tune-up
D/F Biomass Fuel Cell	4	Tune-up	0.003	Tune-up	ng/dscm at 7%O2	Tune-up	Tune-up
D/F Biomass Hybrid Suspension/Grate	0.2	Tune-up	0.2	Tune-up	ng/dscm at 7%O2	Tune-up	Tune-up

HAP/Fuel	Mar 2011 Final	Dec 2012 Final	Mar 2011 Final	Dec 2012 Final	Units	Output Based (lb/MMBtu steam output) Dec 2012 Final	
	Existing Boilers		New Boilers			Existing	New
D/F Coal pulverized	0.004	Tune-up	0.003	Tune-up	ng/dscm at 7%O2	Tune-up	Tune-up
D/F Coal stoker	0.003	Tune-up	0.003	Tune-up	ng/dscm at 7%O2	Tune-up	Tune-up
D/F Coal FB	0.002	Tune-up	0.002	Tune-up	ng/dscm at 7%O2	Tune-up	Tune-up
D/F Oil	4	Tune-up	0.002	Tune-up	ng/dscm at 7%O2	Tune-up	Tune-up
D/F Gas2	0.08	Tune-up	0.08	Tune-up	ng/dscm at 7%O2	Tune-up	Tune-up

If using PM, HCl, or Hg CEMS to comply, limits are 30-day rolling average.

There are also temporary alternate limits for new units constructed between the original proposal date and the date of publication of the final reconsidered rule:

- If your boiler or process heater commenced construction or reconstruction after June 4, 2010 and before May 20, 2011, you may comply with the emission limits in Table 1 or 11 to the rule until 3 years after the date of publication of the rule in the Federal Register.
- If your boiler or process heater commenced construction or reconstruction after May 20, 2011 and before December 23, 2011, you may comply with the emission limits in Table 1 or 12 to the rule until 3 years after the date of publication of the rule in the Federal Register.
- If your boiler or process heater commenced construction or reconstruction after December 23, 2011 and before the date of publication of the rule in the Federal Register, you may comply with the emission limits in Table 1 or 13 to the rule until 3 years after the date of publication of the rule in the Federal Register.

These standards apply at all times the affected unit is operating, except during periods of startup and shutdown. Work practices apply during periods of startup and shutdown:

- You must operate all CMS during startup.
- For startup of a boiler or process heater, you must use one or a combination of the following clean fuels: natural gas, synthetic natural gas, propane, distillate oil, syngas, ultra-low sulfur diesel, fuel oil-soaked rags, kerosene, hydrogen, paper, cardboard, refinery gas, and liquefied petroleum gas.
- If you start firing coal/solid fossil fuel, biomass/bio-based solids, heavy liquid fuel, or gas 2 (other) gases, you must vent emissions to the main stack(s) and engage all of the applicable control devices except limestone injection in fluidized bed combustion (FBC) boilers, dry scrubber, fabric filter, selective non-catalytic reduction (SNCR), and selective catalytic reduction (SCR).
- You must start your limestone injection in FBC boilers, dry scrubber, fabric filter, SNCR, and SCR systems as expeditiously as possible.
- Startup ends when steam or heat is supplied for any purpose.
- You must collect monitoring data during periods of startup, as specified in §63.7535(b). You must keep records during periods of startup. You must provide reports concerning activities and periods of startup, as specified in §63.7555.
- You must operate all CMS during shutdown.
- While firing coal/solid fossil fuel, biomass/bio-based solids, heavy liquid fuel, or gas 2 (other) gases during shutdown, you must vent emissions to the main stack(s) and

operate all applicable control devices, except limestone injection in FBC boilers, dry scrubber, fabric filter, SNCR, and SCR.

- You must comply with all applicable emissions limits at all times except for startup or shutdown periods conforming with this work practice. You must collect monitoring data during periods of shutdown, as specified in §63.7535(b). You must keep records during periods of shutdown. You must provide reports concerning activities and periods of shutdown, as specified in §63.7555.

The emissions and operating limits apply during malfunction periods. You may use the affirmative defense provision to justify violations during malfunction periods that meet the criteria in the rule.

Limited-use boilers and process heaters must complete a tune-up every 5 years. They are not subject to the emission limits, the annual tune-up requirement, or the operating limits. Major sources that have limited-use boilers and process heaters must complete an energy assessment only if the source has other existing boilers subject to this subpart that are not limited-use boilers.

Work practices are required for all new and existing units less than 10 MMBtu/hr in size (biennial tune-up or tune up every 5 years for units with a continuous O_2 trim system and for gas/light liquid units less than or equal to 5 MMBtu/hr) and for all natural gas/refinery gas units and metal process furnace units (annual tune-up for gas units $\geq$10 MMBtu/hr). New units must complete the initial tune-up within 1 year of startup. Existing units must complete the initial tune-up prior to the compliance date. If the unit is not operating on the required date of the tune-up, it must be conducted within one week of startup.

(i) As applicable, inspect the burner, and clean or replace any components of the burner as necessary (you may delay the burner inspection until the next scheduled unit shutdown). Units that produce electricity for sale may delay the burner inspection until the first outage, not to exceed 36 months from the previous inspection. At units where entry into a piece of process equipment or into a storage vessel is required to complete the tune-up inspections, inspections are required only during planned entries into the storage vessel or process equipment;

(ii) Inspect the flame pattern, as applicable, and adjust the burner as necessary to optimize the flame pattern. The adjustment should be consistent with the manufacturer's specifications, if available;

(iii) Inspect the system controlling the air-to-fuel ratio, as applicable, and ensure that it is correctly calibrated and functioning properly (you may delay the inspection until the next scheduled unit shutdown). Units that produce electricity for sale may delay the inspection until the first outage, not to exceed 36 months from the previous inspection;

(iv) Optimize total emissions of CO. This optimization should be consistent with the manufacturer's specifications, if available, and with any NOx requirement to which the unit is subject;

(v) Measure the concentrations in the effluent stream of CO in parts per million, by volume, and oxygen in volume percent, before and after the adjustments are made (measurements may be either on a dry or wet basis, as long as it is the same basis before and after the adjustments are made). Measurements may be taken using a portable CO analyzer; and

(vi) Maintain on-site and submit, if requested by the Administrator, an annual report containing the information in paragraphs (vi)(A) through (C) of this section,

(A) The concentrations of CO in the effluent stream in parts per million by volume, and oxygen in volume percent, measured at high fire or typical operating load, before and after the tune-up of the boiler or process heater;

(B) A description of any corrective actions taken as a part of the tune-up; and

(C) The type and amount of fuel used over the 12 months prior to the tune-up, but only if the unit was physically and legally capable of using more than one type of fuel during that period. Units sharing a fuel meter may estimate the fuel used by each unit.

As provided in 63.6(g), EPA may approve use of an alternative to the work practice standards in the rule.

A beyond the floor requirement is also included for all existing major source facilities having affected boilers or process heaters that would require the performance of a one-time energy assessment by qualified personnel on the affected boilers and energy use systems to identify any cost-effective energy conservation measures (cost effective means items having a payback period of 2 years or less). The energy assessment must be completed prior to the compliance date. An energy assessment completed on or after January 1, 2008, that meets or is amended to meet the energy assessment requirements, satisfies the energy assessment requirement. A facility that operates under an energy management program compatible with ISO 50001 that includes the affected units also satisfies the energy assessment requirement.

The energy assessment must include:

- A visual inspection of the boiler or process heater system.
- An evaluation of operating characteristics of the boiler or process heater systems, specifications of energy using systems, operating and maintenance procedures, and unusual operating constraints.
- An inventory of major energy use systems consuming energy from affected boilers and process heaters and which are under the control of the boiler/process heater owner/operator.
- A review of available architectural and engineering plans, facility operation and maintenance procedures and logs, and fuel usage.
- A review of the facility's energy management practices and provide recommendations for improvements consistent with the definition of energy management practices, if identified.
- A list of cost-effective energy conservation measures that are within the facility’s control.
- A list of the energy savings potential of the energy conservation measures identified.
- A comprehensive report detailing the ways to improve efficiency, the cost of specific improvements, benefits, and the time frame for recouping those investments.

- The energy assessment for facilities with affected boilers and process heaters with a combined heat input capacity of less than 0.3 trillion Btu (TBtu) per year capacity will be 8 on-site technical labor hours in length maximum, but may be longer at the discretion of the owner or operator of the affected source. The boiler system(s) and any on-site energy use system(s) accounting for at least 50 percent of the affected boiler(s) energy (e.g., steam, hot water, process heat, or electricity) production, as applicable, will be evaluated to identify energy savings opportunities, within the limit of performing an 8-hour on-site energy assessment.

- The energy assessment for facilities with affected boilers and process heaters with a combined heat input capacity of 0.3 to 1.0 TBtu/year heat will be 24 on-site technical labor hours in length maximum, but may be longer at the discretion of the owner or operator of the affected source. The boiler system(s) and any on-site energy use system(s) accounting for at least 33 percent of the energy (e.g., steam, hot water, process heat, or electricity) production, as applicable, will be evaluated to identify energy savings opportunities, within the limit of performing a 24-hour on-site energy assessment.
- The energy assessment for facilities with affected boilers and process heaters with a combined heat input capacity greater than 1.0 TBtu/year will be up to 24 on-site technical labor hours in length for the first TBtu/yr plus 8 on-site technical labor hours for every additional 1.0 TBtu/yr not to exceed 160 on-site technical hours, but may be longer at the discretion of the owner or operator of the affected source. The boiler system(s), process heater(s), and any on-site energy use system(s) accounting for at least 20 percent of the energy (e.g., steam, process heat, hot water, or electricity) production, as applicable, will be evaluated to identify energy savings opportunities.
- The on-site energy use systems serving as the basis for the percent of affected boiler(s) and process heater(s) energy production in (1), (2), and (3) above may be segmented by production area or energy use area as most logical and applicable to the specific facility being assessed (e.g., product X manufacturing area; product Y drying area; Building Z).

Energy use system includes the following systems located on-site that use energy (steam, hot water, or electricity) provided by the affected boiler or process heater: (1) process heating; compressed air systems; machine drive (motors, pumps, fans); process cooling; facility heating, ventilation, and air conditioning systems; hot water systems; building envelop; and lighting; or (2) other systems that use steam, hot water, process heat, or electricity provided by the affected boiler or process heater. Energy use systems are only those systems using energy clearly produced by affected boilers and process heaters.

Testing Requirements for Units with Emission Limits that are not Using CEMS:

Affected sources must demonstrate initial compliance with the emission limits within 180 days of the compliance date or within 180 days of startup. Testing must be conducted during representative operating load conditions. Future operating load must not exceed 110 percent of load during testing. Sources that cease burning solid waste and become regulated under Boiler MACT must demonstrate initial compliance within 60 days of the effective date of the waste to fuel switch.

(1) Conduct initial and annual stack tests to determine compliance with the PM emission limits using EPA Method 5 or 17 or conduct initial and annual stack tests to determine compliance with TSM limits using EPA Method 29.

(2) Conduct initial and annual stack tests to determine compliance with the mercury emission limits using EPA method 29, 30B, or ASTM-D6784-02 (Ontario Hydro Method).

(3) Conduct initial and annual stack tests to determine compliance with the HCl emission limits using EPA Method 26A or EPA Method 26 (if no entrained water droplets in the sample).

(4) Use EPA Method 19 to convert measured concentration values to pound per million Btu values.

(5) Conduct initial and annual test to determine compliance with the CO emission limits using EPA Method 10 or install a CO CEMS to demonstrate compliance with the alternate CO CEMS-based emission limits.

- Conduct HCl and Hg performance tests while operating at representative operating load and burning the fuel mixture that has the highest content of Hg and chlorine (may have to do 2 tests) or the highest concentration of TSM if complying with the alternate TSM limit. Develop maximum Cl and Hg (and TSM if applicable) fuel input limits based on fuel sampling and operating parameter monitoring ranges based on initial performance testing. If you are only burning one type of fuel, you are exempt from fuel sampling requirements. Gas 1 fuels being co-fired with other fuels are exempt from fuel analysis, other gases being burned due to control requirements under another subpart are exempt from fuel analysis, all gaseous fuels are exempt from chlorine analysis.

- You can conduct performance stack tests less often for a given pollutant if your performance stack tests for the pollutant for at least 2 consecutive years show that your emissions are at or below 75 percent of the emission limit (or less than low emission limits footnoted "a" in Tables 1 and 2), and if there are no changes in the operation of the affected source or air pollution control equipment that could increase emissions. In this case, you can conduct a performance test every 3 years, but no more than 37 months after the last performance test. If a performance test shows emissions greater than 75 percent of the applicable emission limit (or greater than low emission limits footnoted "a" in Tables 1 and 2), then you revert to annual performance testing for the next 2 years.

- If you elect to demonstrate compliance using emission averaging under §63.7522, you must continue to conduct performance tests annually.

- If you are demonstrating compliance using fuel analysis for mercury or HCl, fuel analysis must be performed monthly and before burning a new type of fuel. You are not required to conduct fuel analysis for fuels used only for startup, shutdown, or transient flame stability purposes. If each of 12 consecutive monthly fuel analyses demonstrates 75 percent or less of the compliance level, you may decrease the fuel analysis frequency to quarterly for that fuel.

- If your affected boiler or process heater is in the unit designed to burn light liquid subcategory and you combust ultra-low sulfur liquid fuel, you do not need to conduct further performance tests if the pollutants measured during the initial compliance performance tests meet the emission limits in Tables 1 or 2 of this subpart providing you demonstrate ongoing compliance with the emissions limits by monitoring and recording the type of fuel combusted on a monthly basis. If you intend to use a fuel other than ultra-low sulfur liquid fuel, natural gas, refinery gas, or other gas 1 fuel, you must conduct new performance tests within 60 days of burning the new fuel type.

- If you are demonstrating that a gaseous fuel meets the Hg specification of an "other gas 1" fuel, you must conduct an initial fuel specification analysis. If the initial mercury constituents in the gaseous fuels are measured to be equal to or less than half of the mercury specification, no further sampling is required. If the initial mercury constituents are greater than half but equal to or less than 75 percent of the mercury specification, only semi-annual sampling need to be conducted. If the initial mercury constituents are greater than 75 percent of the mercury specification, monthly sampling is required.

- Report results of all stack tests and fuel analyses within 60 days of completion. Stack test reports must verify that operating limits have not changed or provide documentation of revised operating limits. Results must be reported to the EPA's online ERT.

Use of Output Based Limits and Emission Credits from Energy Conservation Measures

You can comply with the output based emission limits and take credit for implementing energy conservation measures identified in the energy assessment. To use this approach, you must establish an emissions benchmark, calculate and document the emission credits, develop an implementation plan, comply with the general reporting requirements, and apply the following emission credit procedures:

- Establish a benchmark for each existing affected boiler in terms of trillion Btu per year heat input. The benchmark from which efficiency credits may be generated shall be determined by using the most representative, accurate, and reliable process available for the source. The benchmark shall be established for a one-year period before the date that an energy demand reduction occurs, unless it can be demonstrated that a different time period is more representative of historical operations.
- Determine the starting point from which to measure progress. Inventory all fuel purchased and generated onsite.
- Document all uses of energy from the affected boiler.
- Collect non-energy related facility and operational data to normalize, if necessary, the benchmark to current operations, such as building size, operating hours, etc. If possible, use actual data that are current and timely rather than estimated data.
- Emissions credits can be generated if the energy conservation measures were implemented after January 1, 2008 and if sufficient information is available to determine the value of the credits. The following emission points cannot be used to generate efficiency credits:
  - Energy conservation measures implemented on or before January 1, 2008, unless the level of energy demand reduction is increased after January 1, 2008, in which case credit will be allowed only for change in demand reduction achieved after January 1, 2008.
  - Efficiency credits on shut-down boilers. Boilers that are shut down cannot be used to generate credits unless the facility provides documentation linking the permanent shutdown to energy conservation measures identified in the energy assessment. In this case, the bench established for the affected boiler to which the credits from the shutdown will be applied must be revised to include the benchmark established for the shutdown boiler.
- Credits are generated by the difference between the benchmark that is established for each boiler and the actual energy demand reductions. The credit is equal to the energy input savings divided by the baseline energy input.
- Adjusted emission level for each boiler = (measured emissions, lb/MMBtu)x(1-credit)

The Implementation Plan shall include a description of the energy conservation measures implemented and the energy savings generated from each measure and an explanation of the criteria used for determining that savings.

Operating Limits:

Control Device	Operating Limits
Wet scrubber control	Minimum 30-day rolling average pressure drop and liquid flow is lowest hourly average value measured during performance test (sources not using PM CPMS); For HCl control, minimum 30-day average pH is lowest hourly average value measured during performance test (sources not using HCl CEMS). For HCl control, can also use maximum 30-day average SO_2 concentration based on highest hourly average measured by SO_2 CEMS during HCl performance test.
Fabric filter control (for sources not using PM CPMS)	Operate bag leak detection system and fabric filter such that alarms are less than 5% of the operating time during a semi-annual period, initiate corrective action within 1 hour of an alarm; OR Maintain daily block average opacity <10%
ESP (dry control system, sources not using PM CPMS)	Maintain daily block average opacity <10%
ESP (followed by wet scrubber, sources not using PM CPMS)	Minimum 30-day rolling average total secondary power is lowest hourly average value measured during performance test.
Dry scrubber (sources not using HCl CEMS)	Minimum 30-day rolling average sorbent injection rate is lowest hourly average value measured during performance test (adjusted for load). Or use maximum 30-day average SO_2 concentration based on highest hourly average measured by SO_2 CEMS during HCl performance test.
Carbon injection (sources not using Hg CEMS)	Minimum 30-day rolling average sorbent injection rate is lowest hourly average value measured during performance test (adjusted for load)
Other dry control system (sources not using PM CPMS)	Maintain daily block average opacity <10%
Any PM control device where using PM CPMS	Maintain 30-day rolling average PM CPMS output at or below the lowest 1-hour average measured during the performance test (if test was >75% of limit, otherwise, calculate signal value that would correspond to 75% of the limit and set as maximum 30-day average signal level). Or utilize as PM CEMS and maintain 30-day average emission rate below the limit.
Operating load (if demonstrating compliance using stack testing)	Maintain operating load at or below 110 percent of highest hourly average load during performance test
Oxygen concentration (for boilers and process heaters that are subject to a CO emission limit and not using CO CEMS)	Measure the oxygen concentration during the initial CO performance test. The lowest hourly average oxygen concentration during the most recent performance test is your operating limit, and your unit must operate at or above your operating limit on a 30-day rolling average basis.
Fuel analysis option for HCl, Hg, TSM	Maintain fuel type or fuel mixture such that the calculated emission rate is less than the applicable emission limit.

Operating above established maximum or below established minimum operating limits is a deviation except during performance tests conducted to determine compliance with the emission limits or to establish new operating limits.

Development of Plans:

- Site specific monitoring plan (new plan not required for CEMS and COMS already covered under Part 60)
- Site specific test plan
- Site specific fuel analysis plan
- Emissions averaging plan (if applicable)
- Output based limits emission credits implementation plan (if applicable)

Continuous Compliance/Monitoring Requirements:

- Continuously monitor control device parameters for which operating limits have been developed, 30-day averaging period (except opacity).
- For boilers subject to CO limit, must install an O2 analyzer or O2 trim system (30-day averaging period for O2 operating limit) OR must install CO and O2 CEMS.
- For solid fuel or residual oil-fired boilers with dry control devices not using PM CPMS or bag leak detectors, install COMS and maintain opacity <10%, daily block average.
- If burning multiple fuels, maintain fuel mixture Hg and Cl (and TSM if applicable) content at or below the maximum fuel input levels established during initial performance test (or use Hg or HCl CEMS, 30-day average).
- Boilers in the coal and heavy liquid subcategories with annual average heat input ≥250 MMBtu/hr from solid fossil fuel and/or heavy liquid must install a PM CPMS, 30-day averaging period (or use as PM CEMS, 30-day average).
- Follow applicable plans, including QA requirements for monitoring systems.

Notifications:

- Initial Notification no later than 120 calendar days after you become subject to the rule (even if you submitted one under the 2004 rule);
- Notification of intent to conduct performance test at least 60 days prior to any compliance demonstration;
- Notification of compliance status within 60 days of completion of any compliance demonstration;
- For natural gas fired units that intend to fire an alternative fuel during a curtailment period or supply interruption, a notification of alternative fuel use within 48 hours of the declaration of a period of natural gas curtailment or supply interruption.
- For boilers that choose to commence or recommence burning solid waste, must provide 30 day notice.
- If you intend to switch fuels and change subcategories, provide 30 days notice.

Recordkeeping Requirements:

- Records demonstrating compliance with above requirements, including all required monitoring, fuel analyses, and stack testing.
- Records documenting malfunctions and deviations, including monitor downtime.
- Date, time, occurrence, duration, and fuels fired during startup and shutdown periods.

- Hours of operation and fuel use for each limited use unit.
- Monthly fuel use records.
- Documentation that you are not burning solid waste.
- Records of the dates and the results of each required boiler tune-up.
- Energy assessment.

Reporting Requirements:

- Semi-annual compliance reports with information required in Table 9. For facilities that only have tune-up requirements, submit compliance reports either annually, biennially, or every 5 years, depending on required tune-up frequency. Electronic compliance reporting will be required when the system is operational and reporting templates are developed.
- Submit performance test and RATA results electronically to the ERT within 60 days of completion.