ILLINOIS ENVIRONMENTAL PROTECTION AGENCY

BUREAU OF AIR

DIVISION of AIR POLLUTION CONTROL

PERMIT SECTION

PROJECT SUMMARY for the
DRAFT CLEAN AIR ACT PERMIT PROGRAM (CAAPP) PERMIT

US Steel Corporation
20th and State Streets, Granite City

Illinois EPA ID Number: 119813AAI

Application Number: 96030056

Application Type: Significant Modification

Start of Public Comment Period: June 21, 2009

Close of Public Comment Period: July 21, 2009

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112(J) MACT Determination

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1.0 Introduction

The Illinois EPA is proposing this case-by-case Maximum Achievable Control Technology (MACT) determination for US Steel Corporation's Granite City facility. The Illinois EPA believes that the proposed limitations, air pollution control techniques, work practices and standards, monitoring, and testing represent MACT for this facility. The facility is an integrated steel manufacture that ultimately produces iron and steel. The facility processes and prepares raw material, produces coke, finishes the steel on site. The affected emission units in question are sub-processes of the processes mentioned. The affected emission units for this determination are all combustion sources firing a variety of gaseous fuels: Cogen Boiler #1, Boilers #1 - 10, Boilers #11 - 12, and the #8 Galvanizing Line Process Heaters. See the table below for an affected emission unit breakdown.

Emission Unit		**Fuel**	**Heat Input Rate (mmBtu/hr)**
Cogen Boiler #1		Blast Furnace Gas, Natural Gas	505
Boilers #1 - 10		Natural Gas, Coke Oven Gas, Blast Furnace Gas[1]	60
Boilers #11 - 12		Natural Gas, Coke Oven Gas, Blast Furnace Gas[1]	225
Galvanizing Furnace 7A		Natural Gas	48
Galvanizing Furnace 8		Natural Gas	54.6
#8 Galvanizing Line Process Heaters	Pre-Clean Recirc Tank	Natural Gas	2.7
	Electrolytic Recirc Tank #1	Natural Gas	1.6
	Electrolytic Recirc Tank #2	Natural Gas	1.3
	Hot water Makeup	Natural Gas	4.5
	Chemical Treat Recirc Tank	Natural Gas	0.5
	Chemical Treat Mix Tank	Natural Gas	0.5

1 Capable fuel types but disallowed through this determination: No. 6 residual fuel oil, and waste oils generated at the facility.

2.0 Regulatory Background

Section 112(j) of the Clean Air Act as amended in 1990 requires an owner or operator of a major source of hazardous air pollutant (HAP) to apply for a Title V permit should the U.S. EPA fail to promulgate emission standards under Section 112(d) for an applicable source category under Section 112(c) within 18. The Title V permit that is issued must require the owner or operator to meet a Maximum Achievable Control Technology (MACT) emission limitation for all hazardous air pollutant (HAP) emissions within the source category. Regulations to implement Section 112(j) are codified in 40 CFR Part 63, Subpart B under sections 40 CFR 63.50 through 63.56. The final rule was promulgated on April 5, 2002 (Federal Register / Vol. 67, No. 66, 16582 - 16611).

On June 8, 2007, the United States Court of Appeals for the District of Columbia Circuit vacated the Institutional, Commercial, and Industrial Boiler and Process Heaters MACT Standard (Boiler MACT) found at 40 CFR Part 63, Subpart DDDDD. As a result of this vacatur, the States are now obligated to pursue case-by-case MACT determinations under Section 112(j) of the CAA mentioned above. On August 31, 2007, the Illinois EPA in response to this vacatur sent out letters to all known affected sources requesting the submittal of a Part 2 application. On October 3, 2007, the Illinois EPA received US Steel’s Part 2 application and on November 26, 2007 issued a Notice of Incompleteness. On May 23, 2008, the Illinois EPA received the additional information requested and subsequently deemed the Part 2 application administratively complete on June 16, 2008. At the time of the draft permit, the Illinois EPA believed that a replacement standard would be out before issuance of the US Steel final CAAPP permit and that we could incorporate the replacement rule at that time, this however did not happen. The Illinois EPA therefore initiated a dialog and further request for additional information to supplement the Part 2 application such that a 112(j) case-by-case determination could be made for all applicable emission units at US Steel. The Part 2 application supplement discussed matters such as proposed emission limits and compliance procedures along with supporting rationale. This Part 2 application is being handled as a significant modification to the final CAAPP permit. This final CAAPP permit is currently proposed to USEPA for 45 day review which ends August 03, 2009.

3.0 Application and Permit Requirements

Application content for case-by-case MACT determinations under CAA Section 112(j) are provided at 40 CFR 63.53. In general, the application for a MACT determination must contain the below information, however the owner or operator may cross-reference specific information in any prior submission by the owner or operator to the Agency. Much of the required information has already been provided in the CAAPP Application #96030056 and the construction permit application #06070023 and the remaining is included with this application for a MACT determination.

Required Application Information Pursuant to 40 CFR 63.53		**Where Found**
(a)(1)	The name and address (physical location) of the major source.	CAAPP Application
(a)(2)	A brief description of the major source and an identification of the relevant source category.	CAAPP Application
(a)(3)	An identification of the types of emission points belonging to the relevant source category.	CAAPP Application
(a)(4)	An identification of any affected sources for which a section 112(g) MACT determination has been made.	Not Applicable
(b)(2)(i)	For a new affected source, the anticipated date of startup of operation.	Construction Application
(b)(2)(ii)	Each emission point or group of emission points at the affected source which is part of a category or subcategory for which a Part 2 MACT application is required, and each of the hazardous air pollutants emitted at those emission points.	MACT Application, CAAPP Application, Construction Application
(b)(2)(iii)	Any existing Federal, State, or local limitations or requirements governing emissions of hazardous air pollutants from those emission points which are part of a category or subcategory for which a Part 2 application is required.	CAAPP Application
(b)(2)(iv)	For each identified emission point or group of affected emission points, an identification of control technology in place.	CAAPP Application
(b)(2)(v)	Any additional emission data or other information specifically requested by the permitting authority.	MACT Application
Optional Application Information Pursuant to 40 CFR 63.53		
(b)(3)(i)	Recommended emission limitations for the affected source and support information consistent with 40 CFR 63.52(f). The owner or operator may recommend a specific design, equipment, work practice, or operational standard, or combination thereof, as an emission limitation.	MACT Application
(b)(3)(ii)	A description of the control technologies that would be applied to meet the emission limitation including technical information on the design, operation, size, estimated control efficiency and any other information deemed appropriate by the permitting authority, and identification of the affected sources to which the control technologies must be applied.	Not Applicable
(b)(3)(iii)	Relevant parameters to be monitored and frequency of monitoring to demonstrate continuous compliance with the MACT emission limitation over the applicable	MACT Application

reporting period.	

Permit content for case-by-case MACT determinations under CAA Section 112(j) are provided at 40 CFR 63.52(f). In general, the permit for a MACT determination must contain the below information.

Permit Content Pursuant to 40 CFR 63.52(f)	
(1)	The title V permit must contain an emission standard or emission limitation that is equivalent to existing source MACT and an emission standard or emission limitation that is equivalent to new source MACT for control of emissions of hazardous air pollutants. The MACT emission standards or limitations must be determined by the permitting authority and must be based on the degree of emission reductions that can be achieved if the control technologies or work practices are installed, maintained, and operated properly. The permit must also specify the affected source and the new affected source. If construction of a new affected source or reconstruction of an affected source commences after a title V permit meeting the requirements of section 112(j) has been issued for the source, the new source MACT compliance dates must apply.
(2)	The title V permit must specify any notification, operation and maintenance, performance testing, monitoring, and reporting and recordkeeping requirements. In developing the title V permit, the permitting authority must consider and specify the appropriate provisions of subpart A of this part. The title V permit must also include the information in paragraphs (f)(2)(i) through (iii) of this section.
(2)(i)	In addition to the MACT emission limitation required by paragraph (f)(1) of this section, additional emission limits, production limits, operational limits or other terms and conditions necessary to ensure practicable enforceability of the MACT emission limitation.
(2)(ii)	Compliance certifications, testing, monitoring, reporting and recordkeeping requirements that are consistent with requirements established pursuant to title V and paragraph (h) of this section.
(2)(iii)	Compliance dates by which the owner or operator must be in compliance with the MACT emission limitation and all other applicable terms and conditions of the permit.
(2)(iii)(A)	The owner or operator of an affected source subject to the requirements of this subpart must comply with the emission limitation(s) by the date established in the source’s title V permit. In no case shall such compliance date be later than 3 years after the issuance of the permit for that source, except where the permitting authority issues a permit that grants an additional year to comply in accordance with section 112(i)(3)(B) of the Act, or unless otherwise specified in section 112(i), or in subpart D of this part.
(2)(iii)(B)	The owner or operator of a new affected source, as defined in the title V permit meeting the requirements of section 112(j), that is subject to the requirements of this subpart must comply with a new source MACT level of control immediately upon startup of the new affected source.

4.0 Case-by-Case MACT Analysis

The case-by-case MACT analysis for organic HAP compounds, mercury compounds, non-mercury metal HAP compounds, inorganic HAP compounds are described below.

4.1 Organic HAP Compounds

There are many organic HAP compound emissions from the boilers and process heaters, among which are benzene, formaldehyde, hexane, cyanide, naphthalene, etc. Organic HAP compound formation is the result of incomplete combustion. For boilers and process heaters, control systems for emissions of organic HAP compounds are currently not economically or technically feasible. Instead, reductions of organic HAP compound emissions are achieved through the use of good combustion practice (GCP) such as system design and work practices expected to minimize organic HAP emissions.

4.1.1 Organic HAP Compounds MACT Floor Analysis

In the vacated Boiler MACT (40 CFR 63 – Subpart DDDDD) USEPA explored MACT Floor Analysis and concluded that “except for CO monitoring for organic HAP, add-on control technology is the only factor that significantly controls emissions.” Therefore the emissions of organic HAP compounds are best minimized through good combustion practice (GCP), and consequently, USEPA chose not to propose a direct emission standard for inorganic HAP emissions for existing gaseous fuel fired units. New gaseous fuel fired units were subjected to a CO limitation, however Cogen Boiler #1 is a special case explained below. Boilers #1-12 fuel oil usage is also explained below.
The Illinois EPA therefore proposes a MACT Floor limit for organic HAP compounds largely based on EPA’s still sound rationale in Reference 13. Additionally, EPA Region 5 followed the similar rationale of using CO as surrogate for organic HAPs by proposing and subsequently granting the Title V permit for Veolia ES, Technical Solutions LLC. EPA’s rationale in this regard is found in that permit’s Statement of Basis part 3(E), Reference 14. The Illinois EPA’s proposed MACT Floor limits and practices are found in summary form at Attachment 1: Case-by-case Specific Requirements. Specific rationales are found below:

Cogen Boiler #1:

Emission Limit: The Illinois EPA is not proposing direct emission limits for this unit, as elaborated by the work practice.

Work Practice: This unit is a large fuel combustion emission source; however, it is almost exclusively combusting treated blast furnace gas (BFG) while the minor balance is comprised of natural gas. A restriction requiring combustion of treated BFG at greater than 90% of the unit’s heat input on an annual basis is being mandated. The use of treated BFG is recognized by EPA as being of minimal concern, and discussed in Reference 12. As a result, as long as a work

practice requiring the near exclusivity of the BFG fuel is in place, then no direct MACT emission limits are required.

Testing: No required testing as a result of the work practice.

Monitoring: Due to the work practice for almost exclusive BFG combustion, the unit is required to install and operate a continuous natural gas fuel flow meter. The Illinois EPA contemplated requiring meters for both fuel types (i.e., BFG and natural gas), however complexities with a BFG fuel flow meter (e.g., size, cost, accuracy, etc.) and the fact that there are only two fuels of concern allows for just the one meter.

Recordkeeping: Beyond the normal recordkeeping requirements for this type of unit, natural gas usage based from the continuous natural gas fuel flow meter will be used to determine the ratio of BFG combusted.

Boiler #1-10:

Emission Limit: For the "MACT Floor" the Illinois EPA is proposing a two part limit. The first part is a short term limitation for CO of 200 ppm corrected to 50 percent excess air at a 1-hour average applicable at all times except during periods of startup, shutdown, and malfunction. While the Illinois EPA agrees with the rationale of using CO as surrogate for organic HAPs as was elaborated Reference 13, the vacated NESHAP 40 CFR 63 Subpart DDDDD established a higher CO limit of 400 ppm by volume on a dry basis corrected to 3 percent oxygen at an averaging time of 1 calendar day, the Illinois EPA is proposing that particular limit for purposes of streamlining due to the more stringent applicable state limit for CO of 35 IAC 216.121, which states that:

> No person shall cause or allow the emission of carbon monoxide (CO) into the atmosphere from any fuel combustion emission source with actual heat input greater than 2.9 MW (10 mmbtu/hr) to exceed 200 ppm, corrected to 50 percent excess air. [35 IAC 216.121]

The second part is a long term limitation for CO of 400 ppm by volume on a dry basis corrected to 3 percent oxygen at an averaging time of 1 calendar day applicable at all times. The Illinois EPA is proposing this second part to specifically address the December 8, 2008 Court opinion (Sierra Club v. EPA, 551 F.3d

1019, 1025-26 (D.C. Cir. 2008)), which held that the 1994 exemptions for startup, shutdown, and malfunction ("SSM") events contained in 40 CFR sections 63.6(f)(1) and (h)(1) were constructively reopened by the 2002, 2004, and 2006 rules challenged in these consolidated petitions for review, and the Panel vacated those exemptions because they violate section 112(d) of the Clean Air Act, 42 U.S.C. § 7412(d). The second limit, which necessarily includes all periods of operation, is designed to be able to be "achieved in practice," meaning a limit that is able to be met continuously under reasonably foreseeable worst-case conditions. The proposed limit is greater than the short term limit, in fact equal in to the promulgated limit for new affected units of the vacated 40 CFR 63 Subpart DDDDD, while also providing a longer averaging time. Of note, existing units had no limits for gaseous fuel fired units in the vacated 40 CFR 63 Subpart DDDDD.

Work Practice: These units are medium sized fuel combustion emission sources. While these units are physically capable of firing fuel oils, in the Part II application US Steel has requested to be limited to only the gaseous fuels to avoid the 112(j) determination that would have been associated with the combustion of the fuel oils. Based from this request the Illinois EPA has disallowed the use of fuel oils while allowing the gaseous fuels of treated BFG, natural gas, or treated COG. The combustion of treated BFG has been previously discussed above for the Cogen Boiler #1 including at Reference 12 as a fuel of minimal concern. The Illinois EPA believes the combustion of natural gas at an existing source is recognized by EPA as a fuel of minimal concern. For the purpose of this 112(j) determination, the Illinois EPA has chosen to restrict US Steel's COG combustion to only COG that has been "treated" by the by-products plant. As explained in Section 4.2.1, the by-products plant scrubs volatilized mercury and other contaminants from the foul COG before being returned for use as a fuel. The various by-products (e.g., tar, ammonia, light oils, etc.), recycled materials, and waste become the end recipients of the contaminants. Therefore the combustion of treated COG after being processed through the by-products plant ensures minimal HAP emissions.

Testing: The Illinois EPA is not proposing not to require any initial or periodic performance testing for these units due to their imminent shutdown.

Monitoring: The Illinois EPA is not proposing to require any initial, periodic, or continuous monitoring for these units due to their imminent shutdown.

Recordkeeping: The Illinois EPA is not proposing specific recordkeeping requirements for these units necessary for MACT compliance. However, there are testing , monitoring, and recordkeeping requirements should the source decide to continue operation at a level above 250 mmBtu/hr of combined heat input.

Boiler #11-12:

Emission Limit: For the “MACT Floor” the Illinois EPA is proposing a two part limit. The first part is a short term limitation for CO of 200 ppm corrected to 50 percent excess air at a 1-hour average applicable at all times except during periods of startup, shutdown, and malfunction. While the Illinois EPA agrees with the rationale of using CO as surrogate for organic HAPs as was elaborated Reference 13, the vacated NESHAP 40 CFR 63 Subpart DDDDD established a higher CO limit of 400 ppm by volume on a dry basis corrected to 3 percent oxygen at an averaging time of 1 calendar day, the Illinois EPA is proposing that particular limit for purposes of streamlining due to the more stringent applicable state limit for CO of 35 IAC 216.121, which states that:

> No person shall cause or allow the emission of carbon monoxide (CO) into the atmosphere from any fuel combustion emission source with actual heat input greater than 2.9 MW (10 mmbtu/hr) to exceed 200 ppm, corrected to 50 percent excess air. [35 IAC 216.121]

The second part is a long term limitation for CO of 400 ppm by volume on a dry basis corrected to 3 percent oxygen at an averaging time of 1 calendar day applicable at all times. The Illinois EPA is proposing this second part to specifically address the December 8, 2008 Court opinion (Sierra Club v. EPA, 551 F.3d 1019, 1025-26 (D.C. Cir. 2008)), which held that the 1994 exemptions for startup, shutdown, and malfunction ("SSM") events contained in 40 CFR sections 63.6(f)(1) and (h)(1) were constructively reopened by the 2002, 2004, and 2006 rules challenged in these consolidated petitions for review, and the Panel vacated those exemptions because they violate section 112(d) of the Clean Air Act, 42 U.S.C. § 7412(d). The second limit, which necessarily

includes all periods of operation, is designed to be able to be "achieved in practice," meaning a limit that is able to be met continuously under reasonably foreseeable worst-case conditions. The proposed limit is greater than the short term limit, in fact equal in to the promulgated limit for new affected units of the vacated 40 CFR 63 Subpart DDDDD, while also providing a longer averaging time. Of note, existing units had no limits for gaseous fuel fired units in the vacated 40 CFR 63 Subpart DDDDD.

Work Practice: These units are large fuel combustion emission sources. While these units are physically capable of firing fuel oils, in the Part II application US Steel has requested to be limited to only the gaseous fuels to avoid the 112(j) determination that would have been associated with the combustion of the fuel oils. Based from this request the Illinois EPA has disallowed the use of fuel oils while allowing the gaseous fuels of treated BFG, natural gas, or treated COG. The combustion of treated BFG has been previously discussed above for the Cogen Boiler #1 including at Reference 12 as a fuel of minimal concern. The Illinois EPA believes the combustion of natural gas at an existing source is recognized by EPA as a fuel of minimal concern through EPA's abstention from proposing limitations for that source category (40 CFR 63.7500). For the purpose of this 112(j) determination, the Illinois EPA has chosen to restrict US Steel's COG combustion to only COG that has been "treated" by the by-products plant. As explained Section 4.2.1, the by-products plant scrubs volatilized mercury and other contaminants from the foul COG before being returned for use as a fuel. The various by-products (e.g., tar, ammonia, light oils, etc.), recycled materials, and waste become the end recipients of the contaminants. Therefore the combustion of treated COG after being processed through the by-products plant ensures minimal HAP emissions.

Testing: The Illinois EPA is not proposing to require any initial or periodic performance testing for these units due the requirement for CO CEMs detailed below.

Monitoring: The Illinois EPA is proposing to require CO CEMs for these units for several reasons: the size of the units, the units continuing operation, and as a verification method that only treated COG is being fired. Untreated COG, if fired would register as an increase in the CO level as the level of contaminants present in the untreated

COG would be a driver for increased incomplete combustion.

Recordkeeping: The Illinois EPA is proposing specific recordkeeping requirements for the CO CEMs for MACT compliance.

Galvanizing Furnace #7A & 8:

Emission Limit: For the "MACT Floor" the Illinois EPA is proposing a two part limit. The first part is a short term limitation for CO of 200 ppm corrected to 50 percent excess air at a 1-hour average applicable at all times except during periods of startup, shutdown, and malfunction. While the Illinois EPA agrees with the rationale of using CO as surrogate for organic HAPs as was elaborated Reference 13, the vacated NESHAP 40 CFR 63 Subpart DDDDD established a higher CO limit of 400 ppm by volume on a dry basis corrected to 3 percent oxygen at an averaging time of 1 calendar day, the Illinois EPA is proposing that particular limit for purposes of streamlining due to the more stringent applicable state limit for CO of 35 IAC 216.121, which states that:

> No person shall cause or allow the emission of carbon monoxide (CO) into the atmosphere from any fuel combustion emission source with actual heat input greater than 2.9 MW (10 mmbtu/hr) to exceed 200 ppm, corrected to 50 percent excess air. [35 IAC 216.121]

The second part is a long term limitation for CO of 400 ppm by volume on a dry basis corrected to 3 percent oxygen at an averaging time of 1 calendar day applicable at all times. The Illinois EPA is proposing this second part to specifically address the December 8, 2008 Court opinion (Sierra Club v. EPA, 551 F.3d 1019, 1025-26 (D.C. Cir. 2008)), which held that the 1994 exemptions for startup, shutdown, and malfunction ("SSM") events contained in 40 CFR sections 63.6(f)(1) and (h)(1) were constructively reopened by the 2002, 2004, and 2006 rules challenged in these consolidated petitions for review, and the Panel vacated those exemptions because they violate section 112(d) of the Clean Air Act, 42 U.S.C. § 7412(d). The second limit, which necessarily includes all periods of operation, is designed to be able to be "achieved in practice," meaning a limit that is able to be met continuously under reasonably foreseeable worst-case conditions. The proposed limit is

greater than the short term limit, in fact equal in to the promulgated limit for new affected units of the vacated 40 CFR 63 Subpart DDDDD, while also providing a longer averaging time. Of note, existing units had no limits for gaseous fuel fired units the vacated 40 CFR 63 Subpart DDDDD.

Work Practice: These units are medium size fuel combustion emission sources only capable of firing natural gas. The Illinois EPA believes the combustion of natural gas at an existing source is recognized by EPA as a fuel of minimal concern.

Testing: The Illinois EPA is not proposing to require any initial or periodic testing for these units due the size and fuel type used by these units and the monitoring requirement below.

Monitoring: The Illinois EPA is proposing to require a formal annual combustion evaluation for these units. The annual evaluation is warranted due the size and fuel type used by these units to periodically verify and retune if necessary the good combustion practices needed to minimize HAP emissions.

Recordkeeping: The Illinois EPA is proposing specific recordkeeping requirements for the annual combustion evaluation for MACT compliance.

#8 Galvanizing Line Process Heaters:

Emission Limit: For the "MACT Floor" the Illinois EPA is proposing a short term limitation for CO of 200 ppm corrected to 50 percent excess air at a 1-hour average applicable at all times except during periods of startup, shutdown, and malfunction. While the Illinois EPA agrees with the rationale of using CO as surrogate for organic HAPs as was elaborated Reference 13, the vacated NESHAP 40 CFR 63 Subpart DDDDD established a higher CO limit of 400 ppm by volume on a dry basis corrected to 3 percent oxygen at an averaging time of 1 calendar day, the Illinois EPA is proposing that particular limit for purposes of streamlining due to the more stringent applicable state limit for CO of 35 IAC 216.121, which states that:

> No person shall cause or allow the emission of carbon monoxide (CO) into the atmosphere from any fuel combustion emission source with actual heat input greater than 2.9 MW (10 mmbtu/hr) to exceed 200 ppm, corrected to 50 percent excess air. [35 IAC 216.121]

These are all small emission units (i.e., less than 10 mmBtu/hr each) and should be capable of being "achieved in practice."

Work Practice: These units are very small fuel combustion emission sources only capable of firing natural gas. The Illinois EPA believes the combustion of natural gas at an existing source is recognized by EPA as a fuel of minimal concern.

Testing: The Illinois EPA is proposing to require performance testing upon request for these units due the size and fuel type used by these units.

Monitoring: The Illinois EPA is not proposing to require any periodic or continuous monitoring for these units due the size and fuel type used by these units.

Recordkeeping: The Illinois EPA is proposing specific recordkeeping requirements for any requested performance testing for MACT compliance.

4.1.2 Organic HAP Compounds Beyond the Floor Analysis

Having identified, and proposed the MACT Floor for organic HAP compounds, the next step is to identify a MACT limit based on the beyond-the-floor analysis.

The Illinois EPA is proposing no specific beyond-the-floor analysis. Instead the Illinois EPA finds that after a review of the rationale for beyond the floor for existing and new units in the Proposed Rule for 40 CFR Part 63 Subpart DDDDD, that the EPA's rationale is still sound. Relevant rationale from the Proposed Rule for 40 CFR Part 63 Subpart DDDDD is highlighted at Reference 13.

The Illinois EPA therefore proposes the beyond-the-floor limit for organic HAP compounds based on EPA's prior analysis, which the Illinois EPA believes is still sound.

4.1.3 Organic HAP Compounds MACT

After completion of a Case-by-Case MACT Analysis for organic HAP compounds, the Illinois EPA is proposing MACT limits for organic HAP compounds as a suite of emission limits, work practices, testing, and monitoring. The suite of requirements considered MACT for these units are summarized in Attachment 1: Case-by-case Specific Requirements.

4.2 Metal HAP Compounds

Certain emissions are formed not as a result of the chemical combustion process, but rather are passed through the process. Mercury compounds and other metal HAP compounds formation result of oxidation of the mercury present in the fuel during combustion. To a large extent, metal HAP compounds control systems have not been specifically designed for gaseous fuel combustion emission units.

4.2.1 HAP Metal Compounds MACT Floor Analysis

In processing the 112(j) determination the Illinois EPA investigated the HAP emissions from the affected sources. Among the HAP emissions, the Illinois EPA paid particular attention to the potential emissions of mercury and other metal HAPs. After a review of existing literature, including Reference 12, and examining the nature and process of the emission source, and reviewing mercury emission estimates from the affected sources, the Illinois EPA believes that a direct mercury compound nor metal HAP compounds limit is not warranted.

With regard to mercury, literature reviewed by the Illinois EPA is found in reference References 1 through 11. The most relevant passages in the citations are identified by both underlined and italics formatting for convenience.

Of specific note with regard to mercury emissions from the combustion of coke oven gas (COG) and/or blast furnace gas (BFG) is negligible.

COG: Mercury is present in trace quantities in the feed stock (coal) for the manufacture of coke. Mercury has a boiling point of 675°F, and is vaporized during the coking cycle and carried away along with other impurities creating a foul COG. The foul COG is transported to the by-products plant, see AP42 12.2 flow diagram below. During foul COG processing in the by-products plant, the volatilized mercury is effectively scrubbed from the foul COG, where it remains in a variety of byproducts, recycled materials, and waste. US Steel states that available analyses indicate that mercury can be present in sulfur waste, ammonia still lime sludge, and tar.

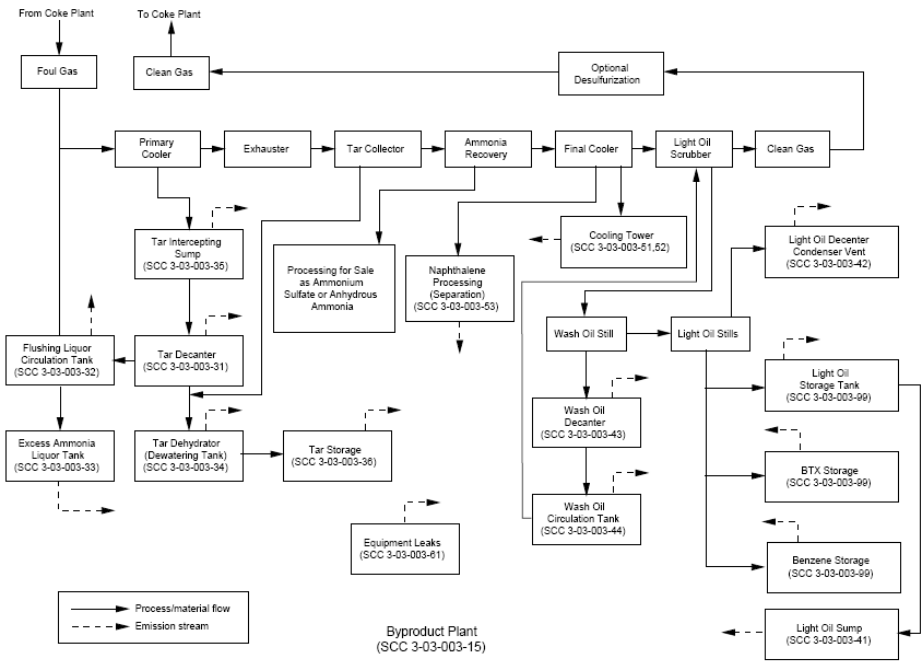

Figure 12.2-3. Flow diagram for coke byproduct recovery plant.
(Source Classification Code in parentheses.)

To understand how the by-product plant effectively acts as a scrubber for the trace mercury in the foul COG, it is important to have a sound understanding of the general operation and function of the coke batteries by-product plant. A basic description of the process is found in AP42 12.2 Coke Production, specifically 12.2.1.4, which is abridged below.

> The coke oven gases, which account for 20 to 35 percent by weight of the initial coal charge and are composed of water vapor, tar, light oils (primarily benzene, toluene, xylene), heavy hydrocarbons, and other chemical compounds. The raw coke oven gas exits the ovens at temperatures of 1400° to 1600°F and is shock cooled by spraying recycled "flushing liquor" in the gooseneck. This spray cools the gas to 176° to 212°F, precipitates tar, condenses various vapors, and serves as the carrying medium for the condensed compounds. These products are separated from the liquor in a decanter and are subsequently processed to yield tar and tar derivatives.
>
> The gas is then passed either to a final tar extractor or an electrostatic precipitator for additional tar removal. When the gas leaves the tar extractor, it carries three-fourths of the ammonia and 95 percent of the light oil originally present in the raw coke oven gas. The ammonia is recovered either as an aqueous solution by water absorption or as ammonium sulfate salt. Ammonium sulfate is crystallized in a saturator that contains a solution of 5 to 10 percent sulfuric acid.

The gas leaving the saturator at about 140°F is taken to final coolers or condensers, where it is typically cooled to about 75°F and where condensed materials are removed (e. g., water, benzene, naphthalene). The gas then passes into a light oil (benzol) scrubber, which uses a heavy petroleum fraction called wash oil (or straw oil) as the scrubbing medium to absorb light oil. The wash oil absorbs about 2 to 3 percent of its weight in light oil and removes about 95 percent of the light oil from the gas. The rich wash oil is stripped in a steam stripper (still), which sends the light oil and water vapors overhead to a light-oil still and condenser for recovery. The lean (stripped) wash oil leaves the bottom of the stripping column and associated decanter and is recycled to the light oil scrubber. The light oil may be sold as crude or processed to recover benzene, toluene, xylene, and solvent naphtha. After tar, ammonia, and light oil removal, the gas undergoes a final desulfurization at some plants to remove hydrogen sulfide. The cleaned coke oven gas has a heating value of approximately 550 Btu/scf but may be as low as 480 Btu/scf. Typically, 35 to 40 percent of the gas is returned to the battery as fuel for the combustion system and the remainder is used for other heating needs, is sold, or is flared in some cases.

Mercury has a boiling point of 675 °F, at which point mercury readily vaporizes. The paragraphs above provide operating temperature data that is well in excess of mercury's boiling point (1400° to 1600°F) and the subsequent shock cooling (176° to 212°F) which condenses out the various compounds, including mercury.

Of specific note with regard to other metal HAP compounds from the combustion of coke oven gas (COG) and/or natural gas, the Illinois EPA believes those levels of emissions are negligible. The Illinois EPA looked at other HAP metals associated with firing of gaseous fuels and determined that a MACT Floor was not necessary given that they are generally found in trace levels for the gaseous fuels being fired in these emission units, see References 2, 8, 11, 16.

Furthermore, the determination to not establish a MACT floor limit for coke oven gas is due to the fact that the other metals are generally low volatility or semi-volatile and would tend to remain in the coke rather than flashing off with the volatiles in the coke oven gas. Those semi-volatiles that would happen to flash off during the coking operation would necessarily be removed with the tars in the by-products plant just as the mercury. See also the Risk Assessment at Reference 2. In addition, it is evident that these trace metals are of no concern since the USEPA, in developing their rulemaking to address the Residual Risk for the Coke Oven MACT, did not feel it necessary to further regulate other HAP metals from combustion stacks on Coke Oven Batteries. See Proposed Coke Oven Battery MACT.

Regarding the use of natural gas, the AP-42 emission factors for metal HAPs other than mercury are generally negligible. This is

evidenced by the fact that USEPA in the development of the vacated Boiler MACT did not consider these metals nor did they evaluate the need for a PM surrogate from the combustion of Natural Gas.

4.2.2 HAP Metal Compounds Beyond the Floor Analysis

Having identified, and proposed the MACT Floor for HAP metal compounds, the next step is to identify a MACT limit based on the beyond-the-floor analysis.

The Illinois EPA is proposing no specific beyond-the-floor analysis. Instead the Illinois EPA finds that after a review of the rationale for beyond the floor for existing and new units in the Proposed Rule for 40 CFR Part 63 Subpart DDDDD, that the EPA’s rationale is still sound. Relevant rationale from the Proposed Rule for 40 CFR Part 63 Subpart DDDDD is highlighted at Reference 13.

The Illinois EPA therefore proposes the beyond-the-floor limit for HAP metal compounds based on EPA’s prior analysis, which the Illinois EPA believes is still sound.

4.3 Inorganic HAP Compounds

The emissions test information available to EPA indicate primary inorganic HAP emitted from boilers and process heaters are acid gases, with HCl present in the largest amounts. Other inorganic compounds emitted are found in much smaller quantities. Inorganic HAP compound formation is the result of oxidation of those constituents in the fuel during combustion. The most effective control technologies identified for removing inorganic HAP that are acid gases, such as HCl, are wet scrubbers and packed bed scrubbers.

4.3.1 Inorganic HAP Compounds MACT Floor Analysis

In processing the 112(j) determination the Illinois EPA investigated the HAP emissions from the affected sources. After a review of existing literature, including Reference 12, and examining the nature and process of the emission source, and reviewing inorganic HAP compounds emission estimates from the affected sources, the Illinois EPA believes that a direct inorganic HAP compounds limit is not warranted.

4.3.2 Inorganic HAP Compounds Beyond the Floor Analysis

Having identified, and proposed the MACT Floor for inorganic HAP compounds, the next step is to identify a MACT limit based on the beyond-the-floor analysis.

The Illinois EPA is proposing no specific beyond-the-floor analysis. Instead the Illinois EPA finds that after a review of the rationale for beyond the floor for existing and new units in the Proposed Rule for 40 CFR Part 63 Subpart DDDDD, that the EPA’s rationale is still sound. Relevant rationale from the Proposed Rule for 40 CFR Part 63 Subpart DDDDD is highlighted at Reference 13.

The Illinois EPA therefore proposes the beyond-the-floor limit for inorganic HAP compounds based on EPA’s prior analysis, which the Illinois EPA believes is still sound.

5.0 References

1) Reference: National Emission Standards for Coke Oven Batteries; Final Rule; Federal Register Vol. 70, No. 72, Friday, April 15, 2005, page 20005

4. Mercury Standards

Comment: *One commenter contended that EPA's proposal was unlawful because it excluded controls for mercury.* The commenter argued that EPA is required to establish emission standards for each HAP and that section 112(f)(2) requires EPA to consider every HAP that a category emits to ensure that the residual risk standards adequately protect public health and the environment. The commenter cited 2002 Toxic Release Inventory (TRI) data that show AK Steel (Ashland, KY) emits 27 pounds of mercury and that Indiana Harbor Coke reported 650 pounds of mercury emissions. Another commenter questioned why mercury and other metals were excluded from door leak emission estimates. According to the commenter, mercury is highly volatile and would be expected to occur in emissions or leaks from any part of the process. The commenter also requested that EPA explain why mercury is missing from the list of metals that were monitored in appendix C of the risk assessment document. While mercury is listed as a component of coke oven emissions in one table in appendix C, it is unclear if or how EPA used this mercury emission factor in its analyses.
Response: *Our research indicates that most of the mercury that is volatilized from the coal during the coking process at by-product coke batteries is concentrated in the tar when the gas is processed in the by-product recovery plant.*[22] *The vast majority of the volatiles distilled from the coal are collected and processed to recover by-products.* However, the commenter is correct in that emission tests have detected mercury emissions from coke ovens. For example, small quantities of coke oven gas may escape through leaks on doors, lids, and offtakes. The emission factor for mercury in Table C– 23 of the risk assessment document shows that trace amounts of mercury have been detected in raw coke oven gas with a ratio to benzene soluble organics (BSO) of 2×10^{-7}. Applying this ratio to the by-product coke plant with the highest BSO emissions (AK Steel in Ashland, Kentucky in Table C–5) gives an estimate of 0.002 lb/yr of mercury emissions from leaks. These low levels of mercury emissions show that mercury emissions from charging, doors, lids, and offtakes do not contribute significantly to the health effects posed by coke oven emissions from by-product coke oven batteries.
[22] Fisher, R. ''Progress in Pollution Abatement in European Cokemaking Industry''. Ironmaking and Steelmaking. vol. 19, no. 6., 1992. Pages 449–456.

2) Reference: Risk Assessment Document for Coke Oven MACT Residual Risk, December 22, 2003, pages 58-59

Discussion: "EPA used information from a variety of data sources (see Appendix C: Documentation of the Emission Estimates) to estimate emissions for those coke oven constituents that were included in the multipathway screen. Information was available for most of the constituents identified with the exception of

mercury. *The emission test results done at ABC Coke which has coke batteries similar to the ones 59 analyzed in this assessment, was not able to detect mercury in the emission streams above the nondetect level (0.2µg). While mercury is known to be present in coal, the starting material for making coke, it's fate during the combustion of coal in power plants is different than its fate during the coking process. Studies performed in Europe (Fisher, 1992) to track the fate of metals during cokemaking, lead to the conclusion that volatile metals like mercury, were distilled from the coal in the first few hours of the coking process and captured (along with volatiles such as benzene) in the coal tar which is sent to the By-product recovery process. While it is possible there may be some mercury emissions from battery emission points at these coke facilities, the data we have were not sufficient to develop quantitative estimates of those emissions for this risk assessment. Further, based on the European study, it is likely that the levels of these emissions would be low from those emission sources associated with the batteries.*"

3) Reference: March 9, 2004 EPA Air Docket No. A-79-15, Item No. XII-B-3

Discussion: EPA's test results of metals for Bethlehem Steel and ABC Coke. All test showed Non Detect for Mercury in COG combustion.

TABLE 2.15

MULTIPLE METALS CONCENTRATIONS AND EMISSION RATES - UNDERFIRE STACK BETHLEHEM STEEL, CHESTERTON, INDIANA

TABLE 2.15 (continued)

Run No.	B-U-315-1	B-U-315-2	B-U-315-3	Average
Copper				
µg/dscm[a]	ND	1.4	0.56	0.66
µg/hr[b]	ND	153,745	81,360	78,368
lb/hr[c]	ND	3.4E-04	1.8E-04	1.7E-04
lb/ton charged[d]	ND	2.4E-06	1.1E-06	1.1E-06
Lead				
µg/dscm[a]	1.3	1.4	0.6	1.1
µg/hr[b]	171,173	148,620	81,360	133,718
lb/hr[c]	3.8E-04	3.3E-04	1.8E-04	2.9E-04
lb/ton charged[d]	2.4E-06	2.3E-06	1.1E-06	1.9E-06
Manganese				
µg/dscm[a]	ND	ND	ND	ND
µg/hr[b]	ND	ND	ND	ND
lb/hr[c]	ND	ND	ND	ND
lb/ton charged[d]	ND	ND	ND	ND
Mercury				
µg/dscm[a]	ND	ND	ND	ND
µg/hr[b]	ND	ND	ND	ND
lb/hr[c]	ND	ND	ND	ND
lb/ton charged[d]	ND	ND	ND	ND

TABLE 2.15

MULTIPLE METALS CONCENTRATIONS AND EMISSION RATES - UNDERFIRE STACK ABC COKE, BIRMINGHAM, ALABAMA

TABLE 2.15 (continued)

Run No.	A-U-315-1	A-U-315-2	A-U-315-4	Average
Copper				
µg/dscm[a]	1.5	1.6	1.8	1.6
µg/hr[b]	99,053	110,128	125,600	111,594
lb/hr[c]	2.2E-04	2.4E-04	2.8E-04	2.5E-04
lb/ton charged[d]	4.3E-06	4.5E-06	7.4E-06	5.4E-06
Lead				
µg/dscm[a]	2.5	2.6	1.7	2.3
µg/hr[b]	163,740	181,3871	116,786	153,971
lb/hr[c]	3.6E-04	4.0E-04	2.6E-04	3.4E-04
lb/ton charged[d]	7.1E-06	7.3E-06	6.9E-06	7.1E-06
Manganese				
µg/dscm[a]	0.74	1.7	2.0	1.5
µg/hr[b]	48,516	120,925	136,618	102,019
lb/hr[c]	1.1E-04	2.7E-04	3.0E-04	2.2E-04
lb/ton charged[d]	2.1E-06	4.9E-06	8.1E-06	5.0E-06
Mercury				
µg/dscm[a]	ND	ND	ND	ND
µg/hr[b]	ND	ND	ND	ND
lb/hr[c]	ND	ND	ND	ND
lb/ton charged[d]	ND	ND	ND	ND

4) Reference: Evaluation of PM2.5 Emissions and Controls at Two Michigan Steel Mills and a Coke Oven Battery, Authored by RTI International for Air Quality Strategies and Standards Division, EPA., February 7, 2007.

Page 27: EPA tests of two coke oven batteries indicate that emissions of HAP metals are just a few pounds per year.[51, 52] Results are summarized in Tables 5-5 and 5-6. These results are consistent with a European study that tracked the fate of metals in the coal that is used for coking.[70] The study found that the

heavier metals (beryllium, arsenic, cobalt, nickel, antimony, chromium, copper, vanadium, and manganese) were largely retained in the coke. *However, cadmium, mercury, thallium, lead, and zinc were volatilized and then recovered in the tar in the by-product recovery plant.* There was no discussion of the ultimate fate of these metals in the tar. (Tar is dewatered and sold to tar refiners who produce coal tar pitch for use as a binder in making graphite electrodes for electric arc furnaces and primary aluminum reduction plants.)

Table 5-5. Test Results for Metals from the Battery Combustion Stack

Metal	lb/ton coke (Plant A)	lb/ton coke (Plant B)	lb/yr (at 1 million tpy coke)
Pb	1.9×10^{-6}	7.1×10^{-6}	1.9 – 7.1
Mn	not detected	5.0×10^{-6}	5.0
Hg	not detected	not detected	—
Ni	not detected	1.9×10^{-6}	1.9

Table 5-6. Test Results for Metals from Pushing Fugitive Emissions[a]

Metal	lb/ton coke (Plant A)	lb/ton coke (Plant B)	lb/yr (at 1 million tpy coke)
Pb	4.2×10^{-6}	1.4×10^{-6}	1.4 – 4.2
Mn	1.3×10^{-5}	1.7×10^{-6}	1.7 – 13
Hg	1.7×10^{-8}	not detected	0.017
Ni	2.5×10^{-6}	1.5×10^{-6}	1.5 to 2.5

[a] Based on sampling at the baghouse inlet and 95 percent capture (5 percent emitted).

Page 50: *The limited test data show no detectable levels of mercury emissions from the combustion of coke oven gas at by-product recovery coke plants. A European study found that most of the mercury distilled from the coal during coking was captured in the by-product recovery process and was removed with the tar.*[70]

5) Reference: Mercury Study Report to Congress, Volume II: An Inventory of Anthropogenic Mercury Emissions in the United States, December 1997

Page 4-73: *Mercury is present in coal in appreciable quantities. Consequently, the volatile gases that evolve from the coking operation are likely to contain mercury (Easterly et al.; U.S. EPA, 1988)*.
Emissions at byproduct coke plants are generated during coal preparation, oven charging operations and other operations. Emissions are also generated from door leaks and from the battery stack. The battery stack emissions are primarily a result of leakage from the oven into the flue. Mercury emissions can be generated in small quantities during coal preparation and handling as fugitive PM because mercury is present as a trace contaminant in coal. *Mercury also may be volatilized and released during charging and pushing operations as well as from the battery stacks and door and topside leaks.*
There are no mercury data for coke ovens in the U.S., so an estimate of U.S. mercury emissions from this source category is not included in this report. There are European emission factors available however, so a rough estimate can be calculated if only to give a sense of the potential magnitude of this source category's emissions. Emission factors used in Germany for coke

production range from 0.01 to 0.03g mercury per Mg of coke produced (Jockel and Hartje, 1991). One difference between European coke producers and U.S. coke producers is that U.S. coke producers use a very high quality cleaned coal while their European counterparts do not. If it is assumed that an emission factor of about 0.025 g mercury per Mg of coke produced is relevant for the U.S. (assuming a 20 percent reduction of mercury by the coal cleaning process), then potential mercury emissions for this source category would be 0.6 Mg/year (0.7 tons/year).

6) Reference: Technical Recommendations for Emission Control Measures for PM2.5 and Metals and for Additional Testing, February 7, 2006, RTI International Memorandum

4. Perform sampling and analysis for mercury species (particulate and vapor phase) for the BOF ESP stack using the Ontario Hydro method or a similar method. Keep records of the types and quantities of scrap melted during the tests. *Our limited data indicate that mercury emissions are not expected from the coke battery combustion stack or the blast furnace stoves.* However, we also recommend at least one test for mercury for these emission points because of the uncertainty and lack of data for mercury emissions.

7) AP42 1.1 Bituminous And Subbituminous Coal Combustion.pdf

8) AP42 12.2 Coke Production.pdf

9) AP42 12.5 Iron And Steel Production.pdf

10) AP42 12.13 Steel Foundries.pdf

11) AP42 1.4 Natural Gas Combustion.pdf

12) Reference: 40 CFR Part 63 National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters; Final Rule; 55218 Federal Register / Vol. 69, No. 176 / Monday, September 13, 2004 page 55228

III. What Are the Significant Changes Since Proposal?

B. Sources Not Covered by the NESHAP
The applicability section of the final rule (40 CFR 63.7490(c)) has been written to clarify that the following are not subject to the final rule: Blast furnace stoves, any boiler or process heater specifically listed as an affected source in another MACT standard, temporary boilers, *and blast furnace gas fuel-fired boilers and process heaters*.

page 55230
Comment: *Many commenters asked EPA to clarify which sources are not covered by the final rule*.
Response: *We have included an extensive list of sources that are not subject to the final rule.*

* * *

We recognize the unique properties of blast furnace gas having high CO concentrations and none to almost no organic compounds. Consequently, we agree that for these sources CO is not a surrogate for organic HAP emissions since CO is the primary component of blast furnace gas and virtually no organic HAP are generated in its combustion. *As a result, we exclude from the final rule units that receive 90 percent or more of their total heat input from blast furnace gas.*

page 55254

40 CFR 63.7491 Are any boilers or process heaters not subject to this subpart?

The types of boilers and process heaters listed in paragraphs (a) through (o) of this section are not subject to this subpart.

(o) Blast furnace gas fuel-fired boilers and process heaters as defined in this subpart.

page 55267 and page 55268

40 CFR 63.7575 What definitions apply to this subpart?

Terms used in this subpart are defined in the CAA, in 40 CFR 63.2 (the General Provisions), and in this section as follows:

Blast furnace gas fuel-fired boiler or process heater means an industrial/ commercial/institutional boiler or process heater that receives 90 percent or more of its total heat input (based on an annual average) from blast furnace gas.

Gaseous fuel includes, but is not limited to, natural gas, process gas, landfill gas, coal derived gas, refinery gas, and biogas. *Blast furnace gas is exempted from this definition.*

13) Reference: 40 CFR Part 63 National Emission Standards for Hazardous Air Pollutants for Industrial/Commercial/Institutional Boilers and Process Heaters; Proposed Rule; Federal Register / Vol. 68, No. 8 / Monday, January 13, 2003

Pages 1679-1680 have an elaborate discussion of EPA's rationale for determining the MACT Floor. With specific reference to EPA's choice and appropriateness for a limit of CO at 400 ppm refer to the below:

H. How Did EPA Determine the MACT Floor for New Units?

Nonetheless, we consider monitoring and maintaining CO emission levels to be associated with minimizing emissions

of organic HAP. Carbon monoxide is generally an indicator of incomplete combustion because CO will burn to carbon dioxide if adequate oxygen is available. Therefore, controlling CO emissions can be a mechanism for ensuring combustion efficiency and may be viewed as a kind of GCP. As discussed previously in this preamble, CO is considered a surrogate for organic HAP emissions in the proposed rule. To determine if CO monitoring would be the basis of the new source MACT floor for organic emissions control, we examined available information. The population databases did not contain information on existing units monitoring CO emissions. *We reviewed State regulations applicable to boilers and process heaters that required the use of CO monitoring to maintain a specific CO limit. We then matched the applicability of each of the State regulations with information on the locations and characteristics of the boilers and process heaters in the population database for each subcategory to determine if each subcategory would have at least one unit that would be required to meet the CO requirements. The analysis of the State regulations indicated that at least one of the boilers and process heaters in the large and limited use subcategories for solid fuel, liquid fuel, and gaseous fuel were required to monitor CO emissions and meet a CO limit of 400 parts per million. Therefore, the new source MACT floor level of control includes a CO work practice standard of 400 parts per million for large and limited use units, reflecting the MACT floor level of control for emissions of organic HAP.*

3. Gaseous Fuel Subcategories

* * *

No existing units were using control technologies that achieve consistently lower emission rates than uncontrolled sources for any of the pollutant groups of interest, except organic HAP. At least one unit in the population database in the large and limited use gaseous fuel subcategories is required to monitor CO. *Therefore, the MACT floor for gaseous fuel-fired units includes a CO monitoring requirement and emission limit, as described previously in this preamble, but it does not include any emission limits for PM, metallic HAP, mercury, or inorganic HAP based on the utilization of add-on control technology.*

E. How Did EPA Consider Beyond-the-Floor Options for Existing Units?

Once the MACT floor determinations were done for each subcategory, EPA considered various regulatory options more stringent than the MACT floor level of control (i.e., technologies or other work practices that could result in lower emissions) for the different subcategories.

* * *

3. Existing Gas-Fired Units The MACT floor for each gaseous fuel subcategory is no emission reductions. The great majority, if not all, of the emissions from gas-fired units are organic HAP. *As discussed previously in this preamble, CO monitoring and*

emission limits were considered as a beyond-the-floor option, but were not selected as MACT given the costs and uncertain HAP reductions achieved. Therefore, no beyond-the-floor control technique was analyzed for organic HAP, and MACT is no emission reduction of non-mercury metallic HAP, mercury, inorganic HAP, and organic HAP.

I. How Did EPA Consider Beyond-the- Floor for New Units?

The MACT floor level of control for new units is based on the emission control that is achieved in practice by the best controlled similar source within each of the subcategories. No technologies were identified that would achieve non-mercury metals reduction greater than the new source floors for the liquid and solid subcategories or CO monitoring for the solid, liquid, and gaseous subcategories. For inorganic HAP control, we determined that packed bed scrubbers achieve higher emissions reductions than MACT floors consisting of a wet scrubber. Packed bed scrubbers are the technology basis of the MACT floor for the large unit subcategory, but wet scrubbers were the technology basis of the floors for the small unit and limited unit subcategories. Therefore, we examined the cost and emission reduction benefits of applying a packed bed scrubber as a beyond-the-floor option for new solid and liquid units within the small and limited use subcategories. The results of this analysis indicated that annualized costs would be an additional 2 million dollars per year for additional reductions of approximately three tons of HCl per year. *We determined that costs were excessive for the limited emissions reductions that would be achieved*.

D. How Did EPA Determine the MACT Floor for Existing Units?

3. Existing Gaseous Fuel Boilers and Process Heaters

Emission data for gas subcategories were inadequate to identify the best performing sources for reasons described in section III.D of this preamble. We also found no State regulations or permits that specifically limit HAP emissions from these sources. Therefore, we examined control technology information to identify a MACT floor. We found that no existing units in the gaseous fuel-fired subcategories were using control technologies that achieve consistently lower emission rates than uncontrolled sources for any of the pollutant groups of interest. Therefore, we are unable to identify the best performing 12 percent of units in the subcategories. Consequently, EPA determined that no existing source MACT floor based on control technologies could be identified for gaseous fuel-fired units. *Therefore, we concluded the MACT floor for existing sources in this subcategory is no emissions reductions for nonmercury metallic HAP, mercury, inorganic HAP, and organic HAP.*

14) Reference:
Statement Of Basis
Air Pollution Control
Title V Permit to Operate
Permit No. V-IL-1716300103-08-01

(E) Section 112(j) Determination

Veolia was subject to 40 C.F.R. part 63, subpart DDDDD, prior to the vacatur of subpart DDDDD in July 2007. (See Natural Resources Defense Council v, EPA, 489 F.3d 1250 (D.C. Cir. 2007).) Subpart DDDDD was a standard promulgated pursuant to section 112(d) of the CAA, 42 U.S.C. § 7412(d). In the absence of a section 112(d) standard, Veolia is subject to section 112(j) of the CAA. Section 112(j) requires the permitting authority to issue a Title V permit with limitations on hazardous air pollutant (HAP) emissions that the permitting authority determines, on a case-by-case basis, to be equivalent to the limitation that would apply to such source if an emission standard had been promulgated in a timely manner under section 112(d). The HAP emitted by natural gas-fired boilers is a variety of organic compounds, collectively referred to as “organic HAP.”

In the vacated section 112(d) standard, EPA chose to use CO as a surrogate to represent organic HAP emitted from the various fuels burned in boilers and process heaters. EPA’s review of existing gas-fired boilers found that no units were using control technologies that achieve consistently lower emission rates than uncontrolled sources for organic HAP, and EPA did not establish a MACT standard for existing gas-fired boilers. Based on a review of CO limits in state regulations, EPA established a standard of 400 parts per million (ppm) for new natural gas fired boilers. (See 68 Fed. Reg. 1660 (January 13, 2003) (proposal), 69 Fed. Reg. 55217 (September 13, 2004) (final).) EPA is proposing a section 112(j) limit for Veolia’s natural gas fired boiler of 100 parts per million by volume (ppmv) CO. EPA believes that, in setting a 112(j) standard for Veolia’s natural gas fired boiler, it is appropriate to use CO as a surrogate to represent organic HAP. Because CO is a difficult-to-destroy refractory compound (i.e., oxidation of CO to carbon dioxide is the slowest and last step in the oxidation of hydrocarbons), it is a conservative surrogate for destruction of hydrocarbons, including organic HAP (See 70 Fed. Reg. 59463 (October 5, 2005)). EPA is aware that natural gas fired boilers can achieve lower CO emissions. However, since EPA has chosen CO as a surrogate for organic HAP, the question is whether those lower CO levels would result in lower organic HAP emissions. As oxidation progresses and hydrocarbon levels decrease, the larger, heavier compounds are destroyed and smaller, lighter compounds form until, ideally, all hydrocarbons are oxidized to CO (and then carbon dioxide) and water. Consequently, the relationship between total hydrocarbons and organic HAP becomes weaker as total hydrocarbon levels decrease to form compounds that are not organic HAP, such as methane and acetylene. Data analyzed for the HWC MACT standard indicate that, at CO levels less than 100 ppmv, most hydrocarbons, including organic HAP, have been destroyed, and

while some residual light organic HAP compounds such as benzene, toluene, and phenol may remain, there is no apparent relationship between carbon monoxide and remaining total hydrocarbons, including remaining organic HAP, at lower CO levels (other than that hydrocarbon levels are generally below 10 ppm when CO levels are below 100 ppm) (See 70 Fed. Reg. 59463-64 (October 5, 2005)). Accordingly, EPA does not believe there is a basis for concluding that reducing CO below 100 ppmv would have any reliable, replicable effect on organic HAP emissions.

Thus, EPA concludes that steps taken to meet the proposed 100 ppm CO limit will result in minimizing organic HAP emissions, and EPA believes, based on the information currently available, that this limit represents the “MACT floor” limit that would be established under section 112(d) for comparable natural gas-fired boilers. EPA also considered, as required by section 112(d), whether we should establish a more stringent “beyond the floor” standard. However, since EPA has determined that there is no basis for concluding that reducing CO below 100 ppmv would have any reliable, replicable effect on organic HAP emissions, EPA is also proposing that it would not be appropriate to establish a “beyond the floor” standard for this natural gas-fired boiler.

EPA notes that the Illinois SIP requires that Veolia meet a 200 ppm CO limit. Because this limit is higher than the section 112(j) limit proposed for the permit, the draft permit contains a “streamlined” limit of 100 ppm. Compliance with the 100 ppm CO limit will assure compliance with the requirements of both the SIP and section 112 of the CAA for this boiler.

16) Reference:
Environmental Protection Agency
40 CFR Part 63
[OAR-2003-0051; FRL-] RIN 2060-AJ96
National Emission Standards for Coke Oven Batteries

For existing by-product batteries, the final rule amendments limit visible emissions from coke oven doors to 4 percent leaking doors for tall batteries and for batteries owned or operated by a foundry coke producer.

6.0 Attachments

Attachment 1: Case-by-case Specific Requirements

Emission Unit	CO Emission Limit	Work Practice	Testing	Monitoring	Recordkeeping	Notes
Cogen Boiler #1	N/A	Fire > 90% of heat input on treated BFG	Not Applicable	Natural Gas Fuel Monitor	Natural Gas Fuel Usage	Replacing Boilers #1-10, under construction
Boilers #1-10	200 ppm 1-Hour 400 ppm 24-Hour	Fire only treated COG, NG, BFG; and follow a SSMP	Not Applicable	Not Applicable	Standard Requirements	Medium units, shutting down with Cogen Boiler #1
Boiler #11-12	200 ppm 1-Hour 400 ppm 24-Hour	Fire only treated COG, NG, BFG; and follow a SSMP	Semi-annual combustion evaluation	CO CEM	Test Reports; Standard Requirements, CO CEM Records	Large units
Galvanizing Furnace #7A & 8	200 ppm 1-Hour 400 ppm 24-Hour	Fire NG; and follow a SSMP	Annual combustion evaluation	Not Applicable	Test Reports; Standard Requirements	Medium units
#8 Galvanizing Line Process Heaters	200 ppm 1-Hour	Fire NG	Test on request	Not Applicable	Test Reports	Very small units