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DEPARTMENT FOR ENVIRONMENTAL PROTECTION

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December 9, 2019

Ms. Mary S. Walker
Regional Administrator
U.S. EPA, Region 4
Sam Nunn Atlanta Federal Center
61 Forsyth Street, SW
Atlanta, Georgia 30303

RE: Request EPA approval of the Louisville Metro Air Pollution Control District Redesignation Request for the 2010 1-Hour Sulfur Dioxide (SO_2) National Ambient Air Quality Standards (NAAQS)

Dear Ms. Walker:

On behalf of the Commonwealth of Kentucky, the Kentucky Energy and Environment Cabinet (Cabinet) respectfully requests that the EPA approve the enclosed final revision to the Jefferson County portion of the Kentucky State Implementation Plan (SIP). Kentucky is seeking approval to redesignate the current nonattainment portion of Jefferson County as attainment for the 2010 1-hour SO_2 NAAQS. EPA designated this portion of the county as nonattainment effective October 4, 2013.[1] Since then, sufficient quality assured ambient air monitoring data has been obtained and demonstrates that the area achieves the 2010 1-hour SO_2 NAAQS.

In accordance with 40 CFR 51.102, the District offered the public 30 days to comment on the proposed SIP revision. A provisional public hearing was scheduled for November 20, 2019, however, it was cancelled after no request for a hearing was received. The cancellation notice was posted on the District's website, www.louisvilleky.gov/apcd/docket.

---

[1] 78 FR 47191

If you have any questions or comments concerning this matter, please contact Ms. Melissa Duff, Director for the Division for Air Quality, at (502) 782-6597 or Melissa.duff@ky.gov.

Sincerely,

Charles G. Snavely
Secretary

c: Beverly Banister, EPA Region 4
Scott Davis, EPA Region 4
Lynorae Benjamin, EPA Region 4
Enclosures

AIR POLLUTION CONTROL DISTRICT
LOUISVILLE, KENTUCKY

GREG FISCHER
MAYOR

KEITH H. TALLEY, SR.
DIRECTOR

November 15, 2019

VIA SPeCS for SIPS

Ms. Melissa Duff, Director
Division for Air Quality
300 Sower Blvd, 2nd Floor
Frankfort, KY 40601

Dear Ms. Duff:

The Air Pollution Control District of Jefferson County (District) requests that the attached material be submitted to the U.S. Environmental Protection Agency (EPA) as revisions to the Jefferson County portion of the Kentucky State Implementation Plan (SIP).

This package contains one SIP request. The District requests that the Commonwealth request the following:

1. Redesignation Request, Louisville/Jefferson County, KY Partial Nonattainment Area, 2010 1-Hour SO2 Standard – Request approval into the Jefferson County SIP.

Your prompt consideration of this request is appreciated. If you have any questions or comments, please contact Byron L. Gary at (502) 574-7253.

Sincerely,

Keith Talley, Sr.
Director

REQUEST FOR EPA ACTION

The Air Pollution Control District of Jefferson County (District) requests a revision to the Jefferson County portion of the Kentucky State Implementation Plan (SIP):

Redesignation Request, Louisville/Jefferson County, KY Partial Nonattainment Area, 2010 1-Hour SO2 Standard

Pollutant/Area Identification

Pollutant: Sulfur Dioxide (SO_2)

Affected Area: Portion of Jefferson County, Kentucky:

That portion of Jefferson County compassed by the polygon with the vertices using Universal Traverse Mercator (UTM) coordinates in UTM zone 16 with datum NAD83 as follows:

(1) Ethan Allen Way extended to the Ohio River at UTM Easting (m) 595738, UTM Northing 4214086 and Dixie Highway (US60 and US31W) at UTM Easting (m) 59751[5], UTM Northing 4212946;

(2) Along Dixie Highway from UTM Easting (m) 597515, UTM Northing 4212946 to UTM Easting (m) 595859, UTM Northing 4210678;

(3) Near the adjacent property lines of Louisville Gas and Electric—Mill Creek Electric Generating Station and Kosmos Cement where they join Dixie Highway at UTM Easting (m) 595859, UTM Northing 4210678 and the Ohio River at UTM Easting (m) 595326, UTM Northing 4211014;

(4) Along the Ohio River from UTM Easting (m) 595326, UTM Northing 4211014 to UTM Easting (m) 595738, UTM Northing 4214086.

Location: Louisville MSA

Area Designation: SO_2 (2010 Standard) – Partial Nonattainment
Ozone (2015 Standard) - Nonattainment

Resulting Emissions Changes:

None. All emissions reductions described in the request were previously approved as part of the Attainment Plan & Demonstration for the area.

Redesignation Request, Louisville/Jefferson County, KY Partial Nonattainment Area, 2010 1-Hour SO_2 Standard

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List of Abbreviations

AERMOD	American Meteorological Society/Environmental Protection Agency Regulatory Model
AQS	U.S. EPA's Air Quality System
CAA	Clean Air Act
CAAA	Clean Air Act Amendments of 1990
CFR	Code of Federal Regulations
FGD	Flue Gas Desulfurization
GEP	Good Engineering Practice
ISIP	Infrastructure SIP
KRS	Kentucky Revised Statutes
KY DAQ	Kentucky Division for Air Quality
LG&E	Louisville Gas & Electric
LMAPCD	Louisville Metro Air Pollution Control District
MMBtu	Million British Thermal Units
NAA	Nonattainment Area
NAAQS	National Ambient Air Quality Standard
NEI	National Emissions Inventory
NNSR	Nonattainment New Source Review
NSR	New Source Review
ppb	parts per billion
PSD	Prevention of Significant Deterioration
PTE	Potential to Emit
RACM	Reasonably Available Control Measures
RACT	Reasonably Available Control Technology
RFP	Reasonable Further Progress
SIP	State Implementation Plan
SO_2	Sulfur Dioxide
U.S. EPA	United States Environmental Protection Agency
UTM	Universal Transverse Mercator

I. Introduction/Background

A. The Standard

On June 22, 2010, the United States Environmental Protection Agency (U.S. EPA) adopted a new Primary National Ambient Air Quality Standard (NAAQS) for sulfur dioxide (SO_2), updating the level, averaging time, and form of the previous standard.[1] This was the first update to the standard since the original adoption of the SO_2 NAAQS in 1971.[2] The Standard, set at 75 parts per billion (ppb), based on the 99th percentile of 1 hour daily maximum concentrations averaged over three years, was retained by U.S. EPA in 2019.[3]

B. Initial Designation

As part of its initial round of nonattainment designations in 2013, U.S. EPA determined a small portion of Louisville/Jefferson County to be nonattainment. Specifically, U.S. EPA designated as nonattainment

> That portion of Jefferson County compassed by the polygon with the vertices using Universal Traverse Mercator (UTM) coordinates in UTM zone 16 with datum NAD83 as follows:
>
> (1) Ethan Allen Way extended to the Ohio River at UTM Easting (m) 595738, UTM Northing 4214086 and Dixie Highway (US60 and US31W) at UTM Easting (m) 59751[5], UTM Northing 4212946;
>
> (2) Along Dixie Highway from UTM Easting (m) 597515, UTM Northing 4212946 to UTM Easting (m) 595859, UTM Northing 4210678;
>
> (3) Near the adjacent property lines of Louisville Gas and Electric—Mill Creek Electric Generating Station and Kosmos Cement where they join Dixie Highway at UTM Easting (m) 595859, UTM Northing 4210678 and the Ohio River at UTM Easting (m) 595326, UTM Northing 4211014;
>
> (4) Along the Ohio River from UTM Easting (m) 595326, UTM Northing 4211014 to UTM Easting (m) 595738, UTM Northing 4214086.[4]

---

[1] Primary National Ambient Air Quality Standard for Sulfur Dioxide, 75 FR 35519 (Jun. 22, 2010).

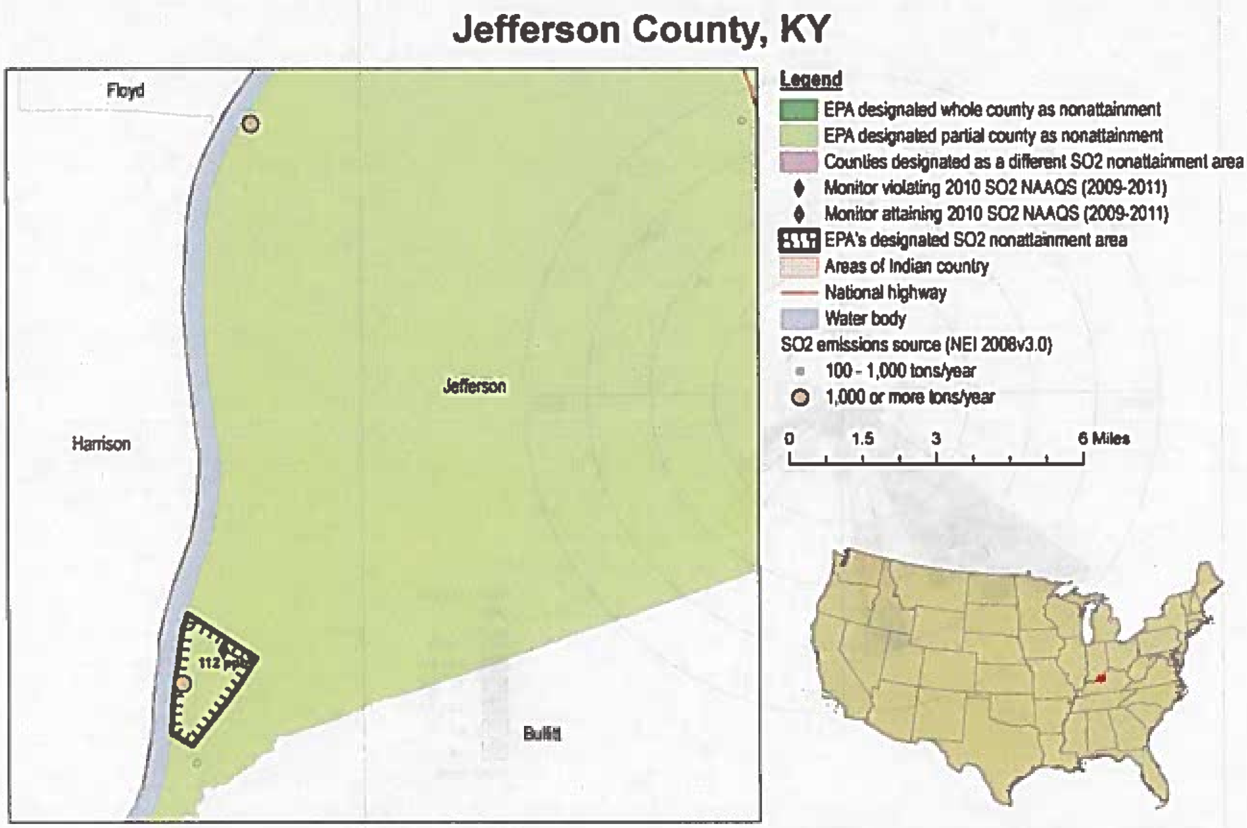
[2] *See* U.S. EPA, Sulfur Dioxide (SO_2) Primary Standards – Table of Historical SO_2 NAAQS at https://www3.epa.gov/ttn/naaqs/standards/so2/s_so2_history.html. The original 1971 standard was both a primary ("requisite to protect the public health," Clean Air Act (CAA) §109(b)(1)) and secondary ("requisite to protect the public welfare from any known or anticipated adverse effects associated with the presence of such air pollutant in the ambient air," CAA §109(b)(2)) standard. The secondary standard was previously retained in 1973, 38 FR 25678, and the original primary standard was retained in 1996, 61 FR 25566. U.S. EPA again retained the 1971 secondary standard in 2012, 77 FR 20218, and retained the 2010 primary standard in 2019, 84 FR 9866.

[3] Review of the Primary National Ambient Air Quality Standards for Sulfur Oxides, 84 FR 9866 (Mar. 18, 2019).

[4] Air Quality Designations for the 2010 Sulfur Dioxide (SO_2) Primary National Ambient Air Quality Standard, 78 FR 47191 at 47200 (Aug. 5, 2013). EPA was required under a consent decree to make further designations in a second round on July 2, 2016, a third round by December 31, 2017, and a final round by December 31, 2020. *See*

This Nonattainment Area (NAA or "the Area") consists primarily of the Louisville Gas & Electric (LG&E) Mill Creek Generating Station (Mill Creek), and the area surrounding the monitor immediately to the north of that facility. A map of the Area is shown below in Figure 1.

Figure 1 - Map of Nonattainment Area[5]



The narrow scope of the Area was based on an analysis of meteorology and SO_2 sources in the Area, which determined that Mill Creek was "likely the major contributor to the violating monitor's design value."[6] Figure 2, below, shows a wind rose for the Watson Lane monitor (the violating monitor on which the designation was based, located at the red diamond in the image above), which demonstrates that winds are predominantly from the direction of Mill Creek when violations of the standard were detected at the monitor.

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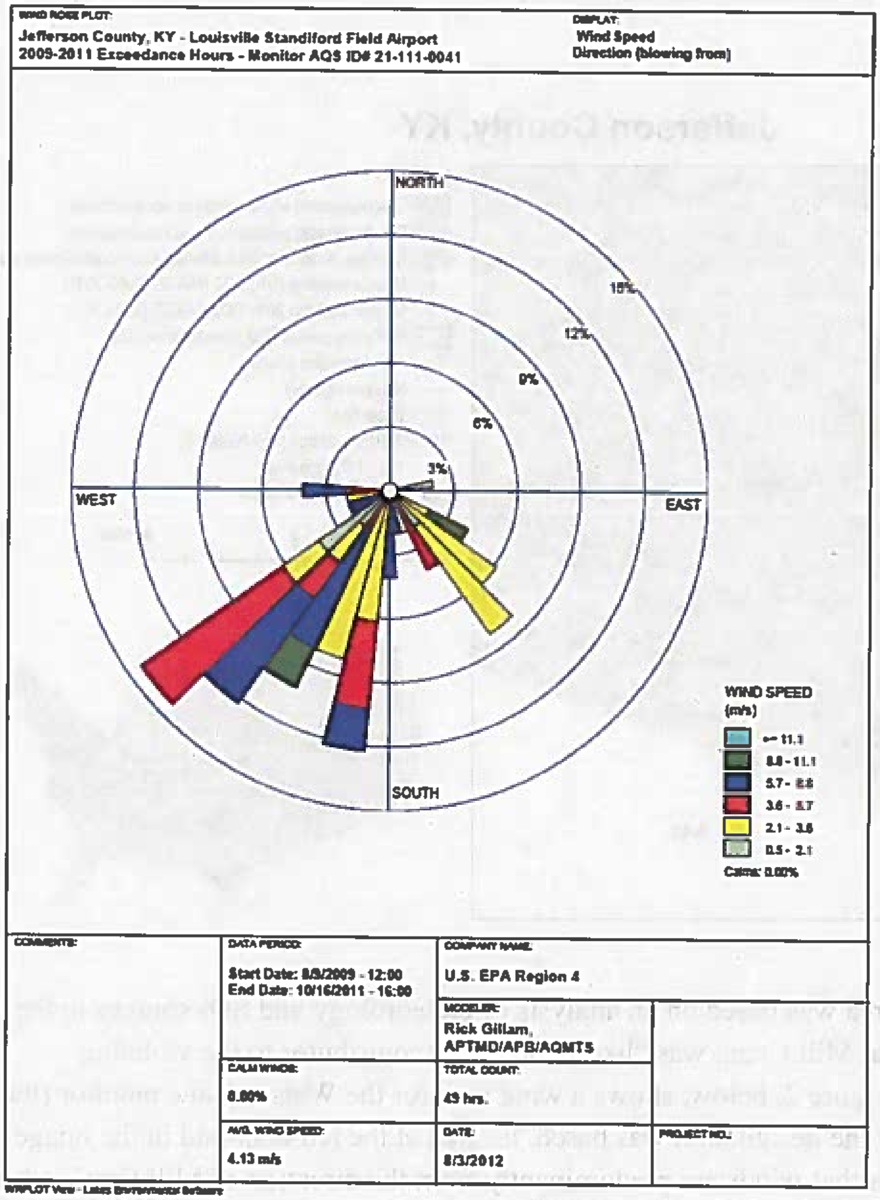
https://www.epa.gov/sulfur-dioxide-designations/learn-about-sulfur-dioxide-designations#status for more information.

[5] *From* U.S. EPA, Technical Support Document (TSD) Kentucky Area Designations For the 2010 SO_2 Primary National Ambient Air Quality Standard (hereinafter "Designation TSD") at 14, *available at* https://www.epa.gov/sites/production/files/2016-03/documents/ky-tsd.pdf.

[6] *Id.* at 19.

Figure 2 - Wind Rose of 2009-2011 hours exceeding the 1-hr SO2 NAAQS at the Watson Lane monitor (AQS ID #21-111-0051)



[7]

The attainment deadline for the Area was set as October 4, 2018.[8]

C. Attainment Demonstration

On June 23, 2017, the Kentucky Division for Air Quality (KY DAQ) submitted, on behalf of the Louisville Metro Air Pollution Control District (LMAPCD), an Attainment Demonstration showing that the Area would reach attainment by the deadline of October 4, 2018. That

[7] *Id.*.
[8] 78 FR at 47193.

Attainment Demonstration also met the other requirements of sections 110(a), 172, 191, and 192 of the Clean Air Act (CAA). Specifically, it contained a base year inventory for 2011, projected attainment year emissions inventory for 2018, an attainment modeling demonstration, provisions for Reasonably Available Control Measures and Reasonably Available Control Technology (RACM/RACT), New Source Review (NSR), Reasonable Further Progress (RFP), and Contingency Measures.[9] U.S. EPA proposed approval of the submittal on November 9, 2018,[10] and finalized approval on June 28, 2019.[11] For more information on the Attainment Demonstration see Section IV, *Approved Implementation Plan*, below.

II. Requirements

A. CAA §107(d)(3)(E)

Pursuant to CAA §107(d)(3)(E), five requirements must be met for an area to be redesignated from nonattainment to attainment:

(E) The Administrator may not promulgate a redesignation of a nonattainment area (or portion thereof) to attainment unless—

(i) the Administrator determines that the area has attained the national ambient air quality standard;

(ii) the Administrator has fully approved the applicable implementation plan for the area under section 7410(k) of this title;

(iii) the Administrator determines that the improvement in air quality is due to permanent and enforceable reductions in emissions resulting from implementation of the applicable implementation plan and applicable Federal air pollutant control regulations and other permanent and enforceable reductions;

(iv) the Administrator has fully approved a maintenance plan for the area as meeting the requirements of section 7505a of this title; and

(v) the State containing such area has met all requirements applicable to the area under section 7410 of this title and part D of this subchapter.[12]

B. Other References & Guidance

Several other provisions in the CAA (such as the Maintenance provisions in §175A referenced at §107(d)(3)(E)(iv)), as well as Guidance documents give further details on the meaning of each of

[9] The full Attainment Demonstration is available in the docket for U.S. EPA's action on the submittal at regulations.gov, under Docket ID EPA-R04-OAR-2017-0625-0001.

[10] Air Plan Approval; Kentucky; Attainment Plan for Jefferson County SO2 Nonattainment Area, 83 FR 56002 (Nov. 9, 2018).

[11] 84 FR 30920.

[12] 42 U.S.C. §7407(d)(3)(E).

these provisions. Two guidance documents are particularly relevant for this submission. In 1992 after the Clean Air Act Amendments of 1990 (CAAA) were passed into law, U.S. EPA published procedures for redesignation in a memo, commonly referred to as the "Calcagni" memo.[13] U.S. EPA adopted further guidance for the 2010 SO_2 Standard in 2014, commonly referred to as the "Page" memo.[14] These documents are referenced throughout this submittal as well.

III. Demonstration of Attainment (§107(d)(3)(E)(i))

According to the Calcagni[15] and Page[16] memos, this requirement consists of two components – monitoring and modeling.

A. Monitoring

Monitoring data has been collected by LMAPCD at Watson Lane Elementary School in the Area since July 16, 1992.[17] Monitoring data from this site was the basis for the initial designation, discussed above in Section I.B. It is the sole monitor in the Area and represents maximum concentrations on a neighborhood scale for SO_2.[18]

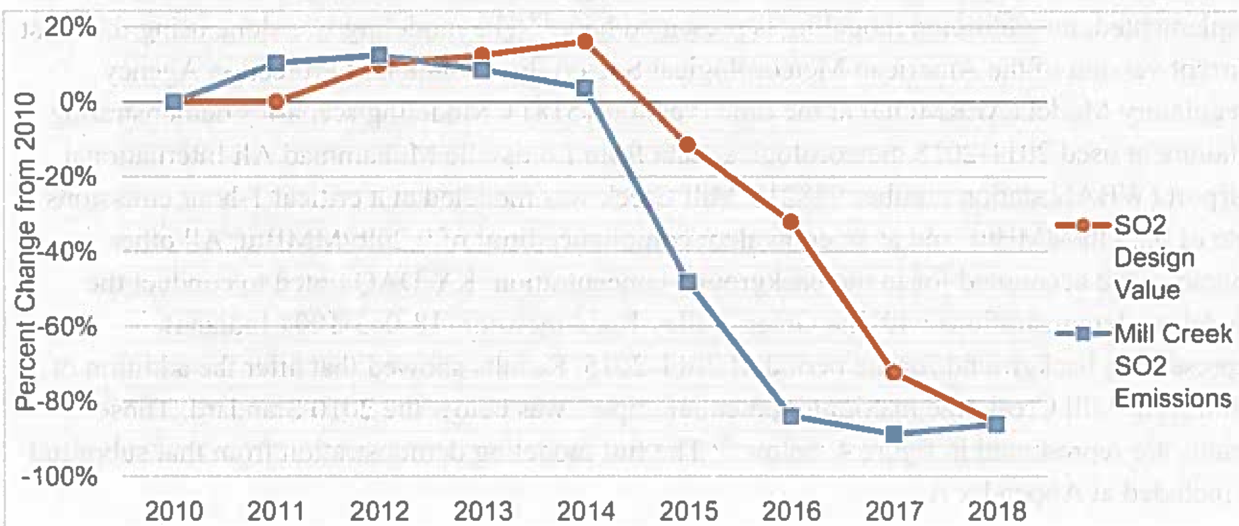
As shown in Figure 3, monitored SO_2 values have declined considerably since the Area was initially designated nonattainment. The design value for the monitor for 2016-2018 is 19 ppb, or roughly a quarter of the 2010 Standard (as retained in 2019).

Figure 3 - SO2 Design Value for Watson Lane Monitor, 2010-2018

[13] Calcagni, John, *Procedures for Processing Requests to Redesignate Areas to Attainment* (Sep. 4, 1992) (hereinafter "Calcagni Memo").
[14] Page, Stephen, *Guidance for 1-Hour SO_2 Nonattainment Area SIP Submissions* (Apr. 23, 2014) (hereinafter "Page Memo").
[15] Calcagni Memo at 2.
[16] Page Memo at 62-63.
[17] For more information, see the *Kentucky Annual Ambient Air Monitoring Network Plan 2018,* attached as Appendix B at p. 66.
[18] Appendix B at p. 66-67.

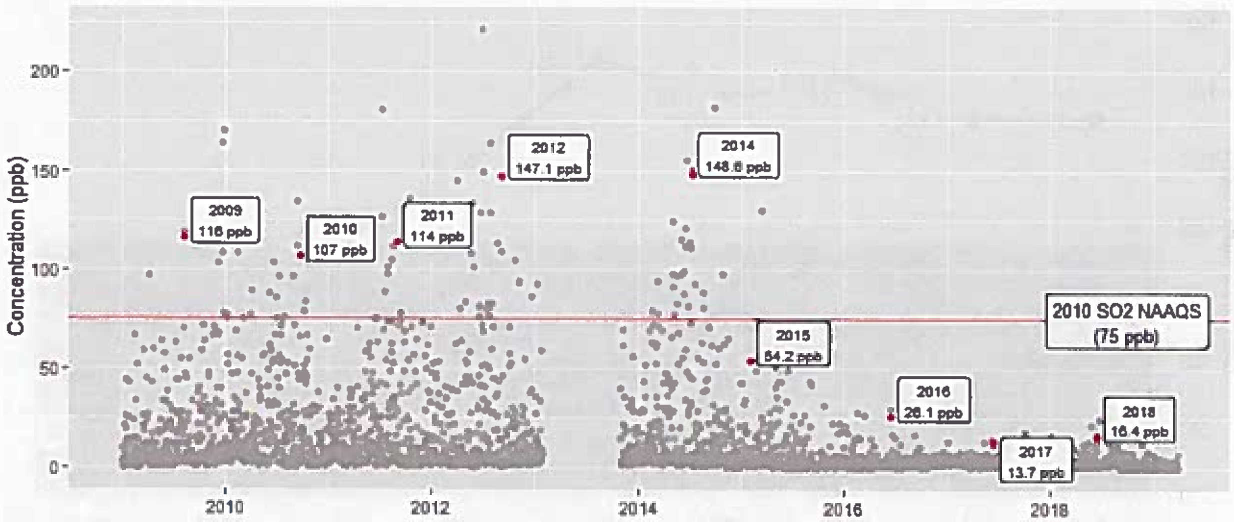
As can be seen from the comparison of the change in the design value at Watson Lane to the change in SO_2 emissions from Mill Creek (figure 4), they are directly correlated.

Figure 4 - Watson Lane Design Value & Mill Creek SO2 Emissions, Percent Change 2010-2018



Furthermore, complete monitoring data has been quality assured and uploaded to U.S. EPA's Air Quality System (AQS) for public access through the first quarter of 2019. There was a gap in quality assured data for 2013; however, subsequent data shows that there have been no daily one-hour maximums over the 75 ppb NAAQS since March 15, 2014.

Figure 5 - Daily Maximum & fourth highest (99th percentile) Annual 1-Hour SO2 Observations, Watson Lane Monitor (21-111-0051), 2009-01-01 to 2019-03-31



B. Modeling

The Attainment Demonstration for the area included modeling conducted by KY DAQ, which demonstrated attainment. The Watson Lane Monitor is located in the area of maximum concentration. Because there have been no significant changes since the submittal of modeling in the Attainment Demonstration and the control strategy from that submittal has been fully implemented, no additional modeling is presented here.[19] The modeling was done using the most current version of the American Meteorological Society/Environmental Protection Agency Regulatory Model (AERMOD) at the time (version 15181). Modeling scenarios demonstrating attainment used 2011-2015 meteorological data from Louisville Muhammad Ali International Airport (WBAN station number 93821). Mill Creek was modeled at a critical 1-hour emissions rate of 0.29 lb/MMBtu, and at an equivalent compliance limit of 0.20lb/MMBtu. All other sources were accounted for in the background concentration. KY DAQ opted to conduct the modeling demonstrations with the Green Valley Road monitor (18-043-1004 Indiana) representing background for the period of 2011-2015. Results showed that after the addition of controls at Mill Creek, the maximum potential impact was below the 2010 Standard. Those results are represented in figure 4, below.[20] The full modeling demonstration from that submittal is included at Appendix A.

Figure 6 - 2017 Modeling Demonstration 4th High Maximum Impact at 0.20 lb/MMBtu Mill Creek Emissions Limit

[19] *See* Calcagni Memo at 3, Page Memo at 62-63.
[20] Levels in the isopleths refer to μg/m³. For reference, 75 ppb of SO_2 is equal to 196.5 μg/m³.

IV. Approved Implementation Plan (§107(d)(3)(E)(ii))

On June 23, 2017, KY DAQ submitted, on behalf of the LMAPCD, an Attainment Demonstration showing that the area would reach attainment by the deadline of October 4, 2018. That Attainment Demonstration also met the other requirements of sections 110(a), 172, 191, and 192 of the CAA. Specifically, it contained a base year inventory for 2011, projected attainment year emissions inventory for 2018, an attainment modeling demonstration, provisions for RACM/RACT, NSR, RFP, and Contingency Measures.[21] U.S. EPA proposed approval of the submittal on November 9, 2018,[22] and finalized approval on June 28, 2019.[23]

The base year and attainment year inventories for all sectors are shown combined, below in Figure 7. The point source inventories for all of Jefferson County are shown in Table 1. Mill Creek was the only point source in the partial county nonattainment area.[24]

Figure 7 - Base year and attainment year emissions inventories for Jefferson County & partial county nonattainment area (from Attainment Demonstration) in tons per year (tpy)

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[21] The full Attainment Demonstration is available in the docket for U.S. EPA's action on the submittal at regulations.gov, under Docket ID EPA-R04-OAR-2017-0625-0001.

[22] Air Plan Approval; Kentucky; Attainment Plan for Jefferson County SO_2 Nonattainment Area, 83 FR 56002 (Nov. 9, 2018).

[23] Air Plan Approval; KY; Attainment Plan for Jefferson County SO_2 Nonattainment Area, 84 FR 30920 (June 28, 2019).

[24] *See* 83 FR at 56006-008 and pp. 6-10 of the Attainment Demonstration for more detail on the inventories. The partial nonattainment area portion of the inventories for sectors other than the point source inventory reflect 0.42% of the total Jefferson County emissions, based on the area of Jefferson County covered by the nonattainment designation.

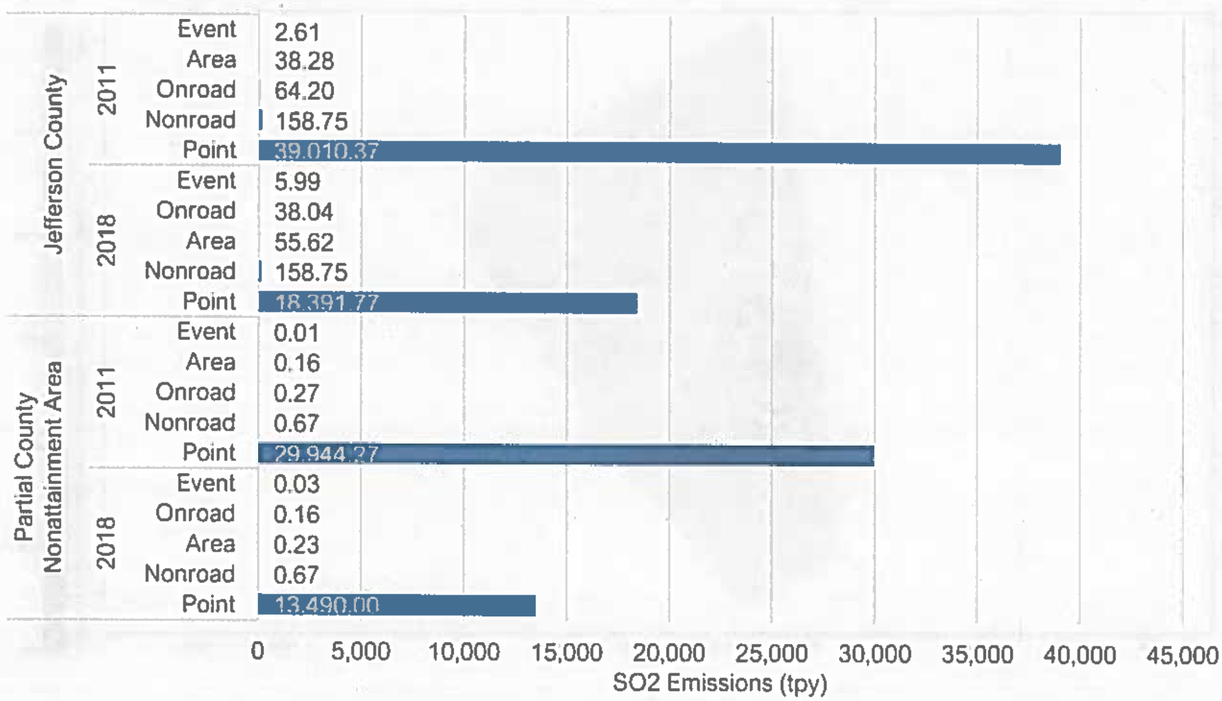

Table 1 - Base Year 2011 sources of SO2 emissions over 10 tons

Facility	EIS Site ID	SO_2 Emissions, tpy
Louisville Gas & Electric - Mill Creek	7353711	29,944.72
Louisville Gas & Electric - Cane Run	5702411	7,823.72
Louisville Medical Center Steam Plant	9613611	475.9
Brown-Forman/Early Times	9612011	257.81
Kosmos	7353311	187.47
American Synthetic Rubber Company	7367811	136.87
Rohm and Haas Company	7350211	28.44

The primary difference between the base year and attainment inventories was the addition of controls to Mill Creek (replacing existing flue gas desulfurization (FGD) equipment with newer and more efficient equipment).[25] This update is reflected in the change in Mill Creek's emissions from 2011 base year actual emissions to its potential to emit (PTE) after adding the new controls (Table 2).[26] With the addition of the new FGDs, emissions within the nonattainment area were modeled and showed attainment, and therefore were determined to constitute RACM/RACT.

Table 2 - Mill Creek emissions, 2011 base year v. new PTE

[25] Additional changes occurred outside the NAA, most significantly the conversion of the Louisville Gas & Electric Cane Run facility from coal-fired boilers to combined cycle natural gas.

[26] The post control potential below was derived by multiplying the new 0.20 lb/MMBtu limit (see Section V for further discussion) by the rated capacity for each unit (e.g., Units 1 & 2 are rated at 3,085 MMBtu/hr (*see* Section 5 for more detail), multiplied by the 0.20 lb/MMBtu limit, multiplied by 8760 hr/yr divided by 2000 lbs/ton = 2703 tons/year).

Operating unit	2011 Emissions	Post-Control Potential	Difference
Unit 1	5,211.00	2,703.00	(2,508.00)
Unit 2	6,802.00	2,702.00	(4,100.00)
Unit 3	7,175.00	3,683.00	(3,492.00)
Unit 4	10,756.00	4,402.00	(6,354.00)
Total	29,944.00	13,490.00	(16,454.00)

V. Permanent & Enforceable Reductions (§107(d)(3)(E)(iii))

LMAPCD reviewed three measures as potential options which could be implemented at Mill Creek in order to reduce ambient SO_2 concentrations and comply with the SO_2 NAAQS:

- More efficient scrubber operation: Operation of FGD scrubbers is the primary method of SO_2 control and can achieve significant reductions in emissions.
- Increases in stack height: An increased release height can decrease ambient concentrations of SO_2 by allowing the plume more time to disperse more efficiently away from turbulent air within the planetary boundary layer. However, the stacks at Mill Creek are already 600 to 615 feet tall and above Good Engineering Practice ("GEP") of 468.77 feet.
- Restriction of high-sulfur fuels: Fuel sulfur content can have a significant effect on SO_2 emissions. There have historically been no restrictions on the types of coal burned at Mill Creek. LMAPCD determined that the enhanced scrubbing provided by the FGDs provide reasonable assurance that the SO_2 emissions from Units 1-4 will result in attainment of the SO_2 NAAQS as expeditiously as practicable, regardless of fuel type, and restrictions of high-sulfur fuels was determined to be unnecessary.

Mill Creek consists of four coal-fired boilers. Units 1 & 2 are tangentially fired boilers, with a rated capacity 3,085 million British Thermal Units (MMBtu)/hr each, which shared a single stack. Units 3 & 4 are dry bottom, wall-fired boilers, with rated capacities of 4,204 and 5,025 MMBtu/hr, respectively, and had individual stacks. LG&E determined that construction of new FGDs along with new chimneys to increase SO_2 removal efficiency was the most reasonable strategy to comply with the revised NAAQS, in part as it allowed continued operation of the units while construction was underway.

LG&E initially applied to install new FGDs at Mill Creek in 2011. Initial plans were to build two new FGDs (one to accommodate Units 1 & 2 and one for Unit 4), and to upgrade one existing FGD (previously in service for Unit 4, upgraded to accommodate Unit 3), to improve SO_2 removal efficiency from 90% to 98% for each unit. These plans were revised in 2013 to include a third new FGD (for Unit 3, in place of upgrades to the old FGD). Construction began in 2013 and ended on June 8, 2016, when the final unit was completed and restarted.

The operation of the new FGDs, along with enforceable emissions limits, were incorporated into a construction permit in 2013 and incorporated into a Title V permit in 2014.[27] The limits were made permanent by way of inclusion in the SIP along with the Attainment Demonstration submitted June 23, 2017. The limits were later revised to eliminate alternative compliance options. The revised Title V permit was issued April 5, 2017, and submitted as a supplement to the initial SIP submittal on August 8, 2018. As stated in the previous section, the SIP was approved on June 28, 2019.

VI. Maintenance Plan (§§107(d)(3)(E)(iv) & 175A)

U.S. EPA must fully approve a maintenance plan meeting the requirements of §175A of the CAA prior to redesignation. However, according to U.S. EPA guidance, a maintenance plan and redesignation request may be submitted at the same time and proceed on a parallel track.[28] This section consists of a complete Maintenance Plan, including contingency measures, submitted for parallel processing by U.S. EPA.

Section 175A and U.S. EPA guidance give five provisions of an approvable maintenance plan[29]:

1. Attainment Inventory
2. Maintenance Demonstration
3. Monitoring Network
4. Verification of Continued Attainment
5. Contingency Plan

These provisions are addressed in turn in the following sections.

A. Attainment Inventory

An attainment emissions inventory should be developed by an air agency as part of a maintenance plan to show the level of emissions sufficient to attain the NAAQS. This generally consists of an inventory of actual emissions at the time monitoring or modeling data shows attainment.[30]

As discussed above, the last exceedance of the NAAQS occurred in 2014. The first three-year period for which the design value for the area fell below the NAAQS is 2015-2017. Phased installation of the new FGDs and restarting of all units at Mill Creek with controls was completed in 2016, making 2017 (the last year of this design value period) the first full year with

[27] *See* Appendix C, Louisville Gas & Electric Mill Creek Generating Station Permit No. 145-97-TV (R6) at Plantwide Specific Condition S1.a.i. (p. 20 of 433): "The owner or operator shall not allow SO2 emissions from any of the boilers U1, U2, U3, or U4, to exceed 0.20 lb/MMBtu of heat input based on a rolling 30-day average."

[28] Calcagni Memo at 7, Page Memo at 65.

[29] Calcagni Memo at 8-13, Page Memo at 66-69.

[30] Calcagni Memo at 8, Page Memo at 66.

the new controls in operation. Complete monitoring data is available through 2018, showing continued observations of low SO_2 concentrations in the area. Because both emissions and the observed 99th percentile of 1-hour daily maximum concentration were slightly higher in 2018 than 2017, LMAPCD conservatively chose this year for the Attainment Inventory.

Actual emissions from Mill Creek as reported to LMAPCD are used for point source emissions for the attainment inventory, as it is the only point source in the nonattainment area, and the only source specifically accounted for in the attainment demonstration. All other sectors are projected from 2011 and 2014 National Emissions Inventory (NEI) values for Jefferson County, and apportioned to the Area based on the fraction of land area covered within the county (~1.5 sq. mi. Area out of 398 sq. mi. total), as follows:

$$AI = \left(NEI_{14} - \frac{NEI_{11} - NEI_{14}}{3} * 4\right) * \left(\frac{1.5}{398}\right)$$

Where:

- AI = Attainment Inventory emissions for sector
- NEI_{14} = 2014 NEI emissions for sector
- NEI_{11} = 2011 NEI emissions for sector
- $\frac{NEI_{11}-NEI_{14}}{3}$ = annual rate of change from 2011 to 2014 NEI
- 4 = years between 2014 NEI and 2018 Attainment Inventory years
- $\left(\frac{1.5}{398}\right)$ = ratio of area of NAA to total Jefferson County area

Table 3 - 2018 LG&E Mill Creek SO2 Emissions

Unit	Source	Emissions (tpy)
MC_U01	CEMS[31]	681.3
MC_U02	CEMS	571.1
MC_U03	CEMS	721.1
MC_U04	CEMS	1778.6
MC_other	Calculated	0.06

Table 4 - Attainment Inventory (2018) SO2 Emissions

Sector	Source	Emission (tpy)
Point	Total	3752.16
Nonpoint	Projected	0.46
Nonroad	Projected	0.01
Onroad	Projected	0.28

B. Maintenance Demonstration

A Maintenance Demonstration generally takes the form of a demonstration that future emissions will not exceed the level of the attainment inventory, or by modeling anticipated future emissions

[31] Continuous Emissions Monitoring System

to show no exceedance of the NAAQS will occur. This should include a projection of emissions at least 10 years following the anticipated date of redesignation of the area.[32]

Mill Creek is the only point source in the NAA. As discussed above in section III.B., the Attainment Demonstration contained modeling showing compliance with the NAAQS based on permitted PTE for Mill Creek. The added controls which were made permanent and enforceable by adoption of the Attainment Demonstration into the SIP are described further at Section V. No major changes have occurred at Mill Creek since the time of adoption of that SIP, nor are any anticipated at this time.

The Area predominantly consists of the Mill Creek property, and a bordering residential neighborhood and school. Furthermore, LMAPCD is not aware of and does not anticipate any future development within the NAA. However, in the event of any future development, any source of air contaminants would be required to go through LMAPCD's permitting process, including SIP-approved requirements for Nonattainment New Source Review (NNSR), or Prevention of Significant Deterioration (PSD) found in LMAPCD Regulations 2.04 & 2.05, respectively.

Table 5 below shows a projected emissions inventory showing attainment year emissions (2018), and Maintenance Inventory (2032), as well as inventories for interim years (2023 & 2028). The development of the Attainment Inventory is described above in section VI.A. Because LMAPCD does not anticipate any development within the NAA, the 2023, 2028, and 2032 point source emissions are identical to the 2018 inventory. The interim year inventories for sectors other than the Point sector are from the U.S. EPA's 2023en and 2028el emissions modeling cases from the 2011v6.3 platform, apportioned to the Area based on the fraction of land area covered within the county in the same manner as for the Attainment Inventory.[33] Those modeling cases are based on versions of the 2011 NEI, and include information needed to support the development of emissions inputs for air quality modeling, including the inventories, ancillary data, and scripts required to process the emissions.[34] The v6.3 platform used here was also used by U.S. EPA in development of the Final Cross-State Air Pollution Rule (CSAPR) Update and for an assessment of ozone transport with respect to the 2015 Ozone NAAQS.[35]

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[32] Calcagni Memo at 9-11, Page Memo at 67.

[33] *Available at* ftp://newftp.epa.gov/air/emismod/2011/v3platform/reports/. Specifically, the files "2023en_county_monthly_report.xlsx"; and "2028el_county_monthly_report.xlsx" within the subfolders "2011en_and_2023en", and "2028el" contain summaries of the 2023 and 2028 inventories, respectively. The "ann_value" for "poll" "SO2" for the "sector_group"s "nonpoint", "nonroad", and "onroad" for "region_cd" 21111 (Jefferson County, Kentucky) were summed to get the inventories for these sectors and years.

[34] *See* U.S. EPA, Technical Support Document (TSD) Preparation of Emissions Inventories for the Version 6.3, 2011 Emissions Modeling Platform, *available at* https://www.epa.gov/sites/production/files/2016-09/documents/2011v6_3_2017_emismod_tsd_aug2016_final.pdf

[35] *See* https://www.epa.gov/air-emissions-modeling/2011-version-6-air-emissions-modeling-platforms

For the 2032 Maintenance Inventory, emissions for all sectors except point sources were chosen based on the higher of either 2023 or 2028 U.S. EPA projected emissions. Because all sectors are dwarfed by point source emissions (the largest other sector being nonpoint with, at most, 0.012% of total emissions in the Area in any of the Attainment Inventory, 2023 case, or 2028 case), and because emissions from all sectors except nonroad (the smallest sector) are projected to decrease dramatically through 2028, this was chosen as a conservative but non-resource-intensive method of developing projected emissions.

Table 5 -Attainment & Projected Future Year NAA Emissions Inventories (tpy)

Sector	2018	2023	2028	2032
Nonpoint	0.46	0.38	0.37	0.38
Nonroad	0.01	0.02	0.02	0.02
Onroad	0.28	0.09	0.08	0.09
Point	3752.16	3752.16	3752.16	3752.16
Total	**3752.91**	**3752.65**	**3752.64**	**3752.65**

C. Monitoring Network

"Once an area has been redesignated to attainment, where air quality monitors exist in an area, the air agency should continue to operate an appropriate air quality monitoring network as provided under 40 CFR part 58 to verify the attainment status of the affected area."[36]

LMAPCD currently operates one ambient SO_2 monitor in the NAA, which is approved under 40 CFR Part 58 and represents maximum concentrations on a neighborhood scale for SO_2. LMAPCD commits to maintaining an appropriate, well-sited monitoring network in the Area through the maintenance plan period in order to verify the continued maintenance of the 2010 SO_2 NAAQS.

D. Verification of Continued Attainment

> Each air agency should ensure that it has the legal authority to implement and enforce all measures necessary to attain and maintain the 2010 SO_2 NAAQS. The air agency's submittal should indicate how it will track the progress of the maintenance plan for the area either through air quality monitoring or modeling.[37]

Kentucky Revised Statutes (KRS) §77.180(1) states

[36] Page Memo at 67, *see also* Calcagni Memo at 11,.
[37] Page Memo at 67-68, *see also* Calcagni Memo at 11-12.

> The air pollution control board of an air pollution control district may make and enforce all needful orders, rules, and regulations necessary or proper to accomplish the purposes of this chapter for the administration of such district, and may perform all other acts necessary or proper to accomplish the purposes of this chapter.

The remainder of KRS Chapter 77 provides LMAPCD with full authority to implement and enforce such orders, rules and regulations, up through and including taking legal action and leveraging fines for violations.

Furthermore, the sole point source within the NAA, Mill Creek, is required to submit annual emissions statements to LMAPCD pursuant to LMAPCD Regulation 1.06. These statements, along with monitoring data collected as described in the previous section, will be used to verify continued attainment. Monitoring data is regularly compared to the NAAQS and reported monthly to the Louisville Metro Air Pollution Control Board.[38] Mill Creek's annual emissions statements will be compared to the Attainment Inventory described in Section VI.A., and the permitted emissions rates for Mill Creek, as previously modeled to result in attainment as described in Section III.B.

E. Contingency Plan

CAA §175A(d) requires a maintenance plan to include contingency measures to ensure any future violation of the NAAQS is promptly corrected. Such measures are not required to take effect automatically as in an Attainment Demonstration pursuant to §172(c)(9), only to be adopted and implemented as expeditiously as practicable. Further, where attainment is reliant on compliance of a single source as here, "the EPA interprets 'contingency measures' to mean that the state agency has a comprehensive program to identify sources of violations of the SO_2 NAAQS and to undertake an aggressive follow-up for compliance and enforcement, including expedited procedures for establishing enforceable consent agreements pending the adoption of revised SIP's."[39]

In the event of a single monitored exceedance of the one-hour, 75 ppb SO_2 NAAQS in the future, LMAPCD will expeditiously investigate and perform culpability analysis to determine the source that caused the exceedance and/or violation and enforce any SIP or permit limit that is violated. LMAPCD implements a comprehensive enforcement and compliance program, as described in part in Section VI.D..

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[38] Air Quality Reports are also made publicly available at https://louisvilleky.gov/government/air-pollution-control-district/air-pollution-control-board-meetings-and-public-hearings.

[39] General Preamble for the Implementation of Title I of the Clean Air Act Amendments of 1990, 57 FR 13547 (April 16, 1992).

If all sources are found to be in compliance with applicable SIP and permit emission limits, LMAPCD shall determine the cause of the exceedance and determine what additional control measures are necessary to impose on the area's stationary sources to continue to maintain attainment of the SO_2 NAAQS. LMAPCD shall inform any affected stationary sources of the monitored SO_2 exceedance and the potential need for additional control measures. Within six months of notification, the source must submit a detailed plan of action specifying additional control measures to be implemented no later than 18 months after the notification, or 24 months from the initial exceedance, whichever comes first LMPACD will continue to implement all measures with respect to the control of SO_2 which were contained in the state implementation plan for the area before redesignation.. The additional control measures will be submitted to the U.S. EPA for approval and incorporation into the SIP.

Such measures may require that Mill Creek reduce load. Additional contingency measures include the alternative RACT/RACM of switching to low-sulfur fuel. Contingency measures will be subject to the necessary administrative and legal process, including publishing notices, notice to U.S. EPA, offering an opportunity for public hearing, and other measures required by Kentucky and Federal law, and incorporated into the permit for a source and/or an Agreed Board Order adopted by the Louisville Metro Air Pollution Control Board pursuant to KRS Chapter 77.

VII. §110 & Part D Requirements (§107(d)(3)(E)(v))

Prior to redesignation, all applicable requirements of section 110 and part D of Title I of the CAA need to be met. Section 110 contains general requirements for a so-called "infrastructure" SIP (ISIP) required to be adopted within three years of the adoption or modification of a NAAQS by U.S. EPA. Part D of title I contains general requirements for nonattainment areas, and specific requirements for certain NAAQS.[40]

A. KY Infrastructure SIP (§110)

CAA §110 contains general SIP requirements, including requirements for public notice and hearing, monitoring for NAAQS, source permitting, PSD, NNSR, modeling, and local agency participation, as well as provisions relating to interstate transport of pollutants. U.S. EPA has stated, however, that because the interstate transport provisions do not relate to the designation or classification of a specific nonattainment area, these are not "applicable" requirements for purposes of considering a request for redesignation.[41]

[40] Calcagni Memo 4-7, Page Memo at 63-64.

[41] *See*, *e.g.*, Air Plan Approval and Designation of Areas; FL; Redesignation of the Nassau County 2010 1-Hour Sulfur Dioxide Nonattainment Area to Attainment, 84 FR 4411 at 4415, (Feb. 15, 2019).

U.S. EPA approved the Kentucky ISIP submission relating to most §110 requirements for the 2010 1-Hour SO_2 NAAQS, including all applicable requirements for purposes of redesignation, effective January 5, 2017.[42]

B. Attainment Demonstration (Part D)

The full Attainment Demonstration, meeting requirements of Part D of Title I of the CAA for the Area was approved by U.S. EPA on June 28, 2019.[43] This submission is discussed further, above, in Section IV.

VIII. Conclusion

The Louisville/Jefferson County 2010 SO_2 1-Hour Nonattainment area, designated by U.S. EPA in 2013, has met all applicable requirements in order to be redesignated to attainment. Monitoring and modeling show the full area to be in attainment; the required Attainment Demonstration has been approved by U.S. EPA; the improvement is due to permanent and enforceable reductions; an approvable maintenance plan accompanies this request; and all other requirements of CAA §110 & Part D of Title I have been met. LMAPCD respectfully requests that this Redesignation Request be submitted to U.S. EPA by KY DAQ, and that the area be redesignated as Attainment by U.S. EPA.

[42] Air Quality Plans; Kentucky; Infrastructure Requirements for the 2010 Sulfur Dioxide National Ambient Air Quality Standard, 81 FR 87817 (Dec. 6, 2016).

[43] Air Plan Approval; KY; Attainment Plan for Jefferson County SO_2 Nonattainment Area, 84 FR 30920 (June 28, 2019).

Appendix A

Kentucky AERMOD Modeling Analysis

1-HOUR SO_2 PLAN
FOR THE LOUISVILLE/JEFFERSON COUNTY, KENTUCKY
NONATTAINMENT AREA

Appendix 3
AERMOD Modeling Analysis Attainment Demonstration

Jefferson County, LG&E Mill Creek SO2 Modeling Demonstration
01/24/17

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Facility Description

Mill Creek generating station currently operates four coal-fired boiler units and three stacks. Mill Creek constructed two new stacks and removed two old stacks. In addition, Mill Creek installed Flue Gas Desulfurization Units (FGDs) on all stacks to show compliance with the Mercury Air Toxics Standards (MATS) as well as other standards. Unit 1 and Unit 2 have a joint stack and a FGD while Unit 3 and Unit 4 have separate stacks, each with FGDs. All construction was completed and operational on June 8, 2016.

In order to evaluate the emission reduction within the nonattainment area, the Division has modeled several scenarios based on the operational SO_2 emissions of Mill Creek. The four scenarios include pre-construction potential-to-emit (PTE) (1.2 lb/MMBtu), pre-construction SO2 clean air markets data (CAMD) from 2009-2013, post-construction critical emission value (CV) (0.29 lb/MMBtu) and the post-construction limit value (0.20 lb/MMBtu).

Table A. Model Scenarios

Emission Scenario Description	Model Label
Pre-construction PTE (1.2 lb/MMBtu)	mc_br01
Pre-construction CAMD (2009-2013)	mc_br01_emi
Post-construction Critical Value (0.29 lb/MMBtu)	mc_ar01
Post-construction Limit (0.20 lb/MMBtu)	mc_ar02

Model Selection

The Division used the American Meteorological Society/Environmental Protection Agency Regulatory Model (AERMOD) (version 15181) to estimate the maximum ground-level concentrations in the Jefferson County, Kentucky nonattainment area. AERMOD is the current regulatory default model for evaluating impacts attributed to industrial facilities in the near-field, and is the recommended model in the EPA's Guideline on Air Quality Models (Appendix W).

Nonattainment Area Boundary

The Jefferson County nonattainment northern boundary runs along Ethan Allen Way extended to the Ohio River, the eastern boundary runs along Dixie Highway, the southern boundary lies between the adjacent property lines of the Mill Creek facility and the Kosmos facility and the western boundary runs along the Ohio River. The nonattainment area boundary layouts are depicted in Appendix A. Aerial Maps, Figures A-1 and A-2.

Receptor Grid

For the maximum predicted impact inside the nonattainment area, a receptor grid of 100 meter spacing was utilized inside the boundary. The receptors, forming the nonattainment area boundary line, are set at 50 meter spacing. Since the Mill Creek facility boundary is completely inside the nonattainment boundary area, the facility boundary was removed. A discrete Cartesian receptor (X-coordinate 596670.51, Y-coordinate 4213146.30) was positioned to represent the Watson Lane monitor. The receptor grids utilized in the modeling demonstration are depicted in Appendix A. Aerial Maps, Figures A-3 and A-4.

Modeled Source Inventory

The Division collaborated with the Louisville Metro Air Pollution Control District (LMAPCD) to acquire appropriate modeling parameters for this demonstration. LMAPCD provided building parameters and stack parameter information to the Division. Building downwash was applied in the demonstrations. The BPIPPRIME (version 04274) program was used to process building inputs for AERMOD. Since the actual stack heights at the Mill Creek facility exceed Good Engineering Practice (GEP), the GEP stack heights were used for each stack.

The PTE emission value of 1.2 lb/MMBtu was derived from the permit 145-97-TV (R1). The critical emissions value of 0.29 lb/MMBtu was developed using AERMOD modeling and the 2010 SO_2 NAAQS for SO_2. This hourly average critical emission rate was converted to 0.20 lb/MMBtu averaged over 30-days with a conversion ratio of 0.69 based on the Guidance for 1-Hour SO_2 Nonattainment Area SIP Submissions Memorandum from U.S. EPA Office of Air Quality Planning and Standards Director Stephen D. Page (April 23, 2014). The 0.20 lb/MMBtu heat input limitation was derived from the permits 145-97-TV (R2) and O-0127-16V. The CAMD data, utilized for the years 2009-2013, will be provided in an additional spreadsheet. Emissions parameters are tabulated and depicted in Appendix B. Emission Source Parameters, Tables B-1 through B-4.

The Division assumed that 100% load scenario would be the worst-case scenario; therefore, no other loads were analyzed for the modeling demonstration.

Coordinate System

The location of emission sources, structures, and receptors for all modeling analyses were represented in the Universal Transverse Mercator (UTM) coordinate system. The UTM grid divides the world into coordinates that are measured in north meters (measured from the equator) and east meters (measured from the central meridian of a particular zone, which is set at 500 kilometers (km)). The datum is based on World Geodetic System 1984 (WGS84). UTM coordinates for this demonstration all reside within UTM Zone 16.

Meteorological Data

In compliance with the EPA air quality modeling guideline found in Section 8.4.2.e of Appendix W, the modeling performed for the Jefferson County nonattainment area relied on five years of consecutive meteorological data taken from the most representative surface and upper air meteorological stations. The representativeness of the meteorological data station was evaluated on 1) proximity to the facility; 2) complexity of terrain; 3) exposure of the meteorological monitoring site; and 4) the time period data were collected. In addition, the Division compared the predicted maximum impacts utilizing the Standiford (KSDF) and Bowman Field (KLOU) surface stations located in Louisville, Kentucky. Both runs were performed at PTE (1.2 lb/MMBtu) and without background inventory. The resulting impact concentration maps can be found in Appendix C. Meteorological Station Evaluation, Figures C-1 and C-2.

The four modeling scenarios incorporated meteorology data from 2009-2015. The two scenarios modeled prior to construction (mc_br01, mc_br01_emi) utilized meteorology data from 2009-2013. The two scenarios modeled post construction (mc_ar01, mc_ar02) utilized meteorology data from 2011-2015. The meteorological data was processed using AERMET version 15181 and AERMINUTE version 15727. The surface data was derived from the Louisville Standiford Field surface station (WBAN station number 93821). TD-6405 1-minute data (ASOS) was added to the surface data processing including the "Ice –Free Wind Group" and threshold wind speed 0.5 m/s options. The upper air data was derived from Wilmington Air Park, Wilmington, Ohio (WBAN station number 13841).

Surface Roughness

According to the AERMOD Implementation Modeling Guidelines, the meteorological stations should be representative of the facility. The National Weather Service (NWS) meteorological station chosen for Mill Creek depended on the meteorological tower location, topography, land use, and surface characteristics in reference to Mill Creek. The surface roughness values of the meteorological surface station utilized data processed by AERSURFACE version 13016. In AERSURFACE, the default 1 km radius was chosen, temporal resolution was set to "monthly", and twelve 30° averaged sectors were chosen for each analysis. The surface station meteorology spreadsheets, surface_sdf_iln09-13 and surface_lou_iln09-13, will be included as additional material.

Terrain Treatment

Receptor elevations and hill heights required by AERMOD were determined using the AERMAP terrain preprocessor (version 11103). Terrain elevations from the USGS 1-arcsecond NED data were used for the AERMAP processing of receptors and source inventory.

Dispersion Coefficient

According to Appendix W Section 7.2.1.1.b.i, the land use procedure (Auer method) can be used to classify the land use within the total area circumscribed by a 3 km radius circle about the source using meteorological land use typing scheme proposed by Auer. If the land use types I1, I2, C1, R2, and R3 account for 50 percent or more of the area, an urban dispersion coefficient would be used; otherwise a rural dispersion coefficient would be used. The Division used aerial photography and 1992 National Land Cover Data to define the dispersion coefficient. Compared to the Auer land use typing schemes, the most analogous urban land use schemes in the 1992 NLCD are the *high intensity residential* and *commercial/industrial/transportation* schemes. The Division analyzed the land use categories within a 3 km radius of the source and determined that the rural dispersion coefficient was the most appropriate dispersion coefficient. Refer to Appendix C. Dispersion Coefficient, Figures C-1 and C-2.

Monitoring Background Data

According to Appendix W Section 8.3.2.b, a "regional site" monitor outside the nonattainment area can be utilized to determine background. The Watson Lane monitor (21-11-0051 Kentucky), Cannons Lane Monitor (21-111-0067 Kentucky) and Algonquin Parkway monitor (21-111-1041 Kentucky) were determined to have issues with the completeness of data and not utilized in this demonstration. The Division opted to conduct the modeling demonstrations with the Green Valley Road monitor (18-043-1004 Indiana) representing background for the period of 2011-2015. Locations of the SO_2 monitors are depicted in Appendix D. Monitoring Background Data, Figure D-1.

The Division acquired the monitor's raw data report from the EPA Air Quality System (AQS). The Division processed the season-by-hour background concentration data by taking the 3-year average of the 2nd highest values by hour-of-day per each season. The ambient monitoring data reported for hour 00 was paired with modeled/meteorological data for hour 01, etc. The background data was incorporated into the model and monitor data was automatically combined with the modeled concentration. Therefore, post processing pairing was not necessary. The season-by-hour background concentrations utilized in the modeling demonstration is depicted below in Table 1 and Table 2.

Table 1. Season-by-Hour Monitoring Data, Green Valley Road (Site ID: 18-043-1004)

	2011-2013			
Hour (Ending of Hour Period)	**Winter**	**Spring**	**Summer**	**Fall**
01:00	7.70	7.93	5.55	2.13
02:00	5.50	8.93	5.05	2.93
03:00	5.43	11.40	3.10	3.63
04:00	5.60	8.90	3.60	3.93
05:00	5.60	5.33	2.90	3.30
06:00	7.50	4.73	3.05	3.53
07:00	7.30	5.67	3.25	4.23
08:00	7.40	8.47	4.40	4.13
09:00	7.13	11.27	11.95	5.90
10:00	7.83	14.60	12.25	8.20
11:00	10.93	14.17	15.40	13.43
12:00	13.93	14.37	15.75	20.67
13:00	18.27	12.20	13.10	18.50
14:00	19.70	18.20	12.20	15.13
15:00	15.83	13.87	10.10	16.60
16:00	20.43	12.20	9.05	12.83
17:00	14.37	10.23	8.40	15.73
18:00	10.03	11.07	14.10	10.50
19:00	8.47	13.93	15.00	6.97
20:00	7.00	10.93	14.50	5.90
21:00	5.43	11.43	10.85	4.23
22:00	6.43	11.53	6.75	4.63
23:00	9.60	11.67	6.85	6.77
24:00	8.57	8.00	5.15	3.43

Table 2. Season-by-Hour Monitoring Data, Green Valley Road (Site ID: 18-043-1004) 2013-2015

Hour (Ending of Hour Period)	Winter	Spring	Summer	Fall
01:00	8.53	8.37	3.50	2.60
02:00	6.03	6.93	2.50	2.63
03:00	5.97	8.43	2.10	2.53
04:00	5.53	6.17	2.23	2.03
05:00	5.37	6.00	1.77	1.60
06:00	5.73	3.97	1.43	1.63
07:00	5.03	4.50	1.97	3.70
08:00	7.00	4.63	3.00	3.57
09:00	6.60	9.00	7.23	5.80
10:00	10.30	10.23	8.57	7.00
11:00	10.47	14.03	18.57	13.13
12:00	15.63	15.17	15.70	16.87
13:00	16.83	19.73	11.87	16.47
14:00	20.40	19.87	12.10	14.90
15:00	16.20	15.77	11.63	14.27
16:00	14.30	16.70	8.03	14.17
17:00	12.73	14.03	6.63	11.40
18:00	11.03	11.43	7.47	9.00
19:00	10.73	14.57	5.17	10.13
20:00	8.57	11.40	4.90	5.93
21:00	7.43	14.63	4.77	4.83
22:00	10.43	9.97	3.10	6.93
23:00	8.93	12.47	3.80	5.87
24:00	10.50	8.77	2.57	3.07

In order to evaluate the impact of the background inventory on the Watson Lane monitor, the Division incorporated subgroups based on monitor data to all scenarios. The two scenarios modeled prior to construction (mc_br01, mc_br01_emi) utilized monitor data from 2011-2013. The two scenarios modeled post construction (mc_ar01, mc_ar02) utilized monitor data from 2013-2015. In addition, each of the four scenarios was run with season-by-hour monitor data (_sshr) and without season-by-hour monitor data (_nb). The maximum predicted impacts from all scenarios modeled with and without the Green Valley background monitor data are tabulated in Tables 3 and 4, respectively.

Summary of Modeling Results

The Division compared the five year average of the high fourth-high (H4H) one hour concentrations to the 1-hour SO2 standard. The high fourth high is a surrogate for the 99th percentile. The four scenarios depicted in the modeling demonstrations include mc_br01 (PTE), mc_br01_emi (CAMD), mc_ar01 (CV), and mc_ar02 (Limit). Each of the four scenarios utilized the parameters referenced in Appendix B. Emission Source Parameters, Tables B-1 through B-4.

The model demonstrations representing emission data prior to construction (mc_br01_sshr and mc_br01_emi_sshr) predict maximum impacts well above the 1 hour SO_2 NAAQS within the nonattainment area and at the Watson Lane monitor. The model demonstrations representing emission data post construction (mc_ar01_sshr and mc_ar02_sshr) predict reduced H4H maximum impacts below the 1 hour SO_2 NAAQS within the nonattainment area and at the Watson Lane Monitor. The H4H maximum impacted receptor and the Watson Lane monitor receptor for each scenario (including background) are tabulated in Table 3. Maps containing the maximum H4H impact concentrations for each scenario are depicted in Appendix F. Additional Modeled Impacts, Figures F-1 through F-4.

Table A. Model Scenarios

Emission Scenario Description	Model Label
Pre-construction PTE (1.2 lb/MMBtu)	mc_br01
Pre-construction CAMD (2009-2013)	mc_br01_emi
Post-construction Critical Value (0.29 lb/MMBtu)	mc_ar01
Post-construction Limit (0.20 lb/MMBtu)	mc_ar02

Table 3. Predicted Modeling Results including Green Valley Road SO_2 monitor ($\mu g/m^3$)

Model RUN	1 Hour SO_2 NAAQS $\mu g/m^3$	H4H Maximum Receptor Impact $\mu g/m^3$	H4H Watson Lane Receptor Impact $\mu g/m^3$
mc_br01_sshr	195.6	1160.49	1023.83
mc_br01_emi_sshr		535.63	508.87
mc_ar01_sshr		190.1	184.37
mc_ar02_sshr		145.5	140.14

*sshr = season-by-hour monitoring data

In addition, the Division wanted to evaluate the Mill Creek generated impact on the nonattainment area excluding background. The information would also provide valuable data for the future comparison of SO_2 model impacts versus monitor sample data. The model demonstrations representing emission data prior to construction (mc_br01_nb and mc_br01_emi_nb) predict maximum impacts well above the 1 hour SO_2 NAAQS within the nonattainment area and at the Watson Lane monitor. The model demonstrations representing emission data post construction (mc_ar01_nb and mc_ar02_b) predict reduced H4H maximum impacts below the 1 hour SO_2 NAAQS within the nonattainment area and at the Watson Lane Monitor. The H4H maximum impacted receptor and the Watson Lane monitor receptor for each scenario (omitting background) are tabulated in Table 4. Maps containing the maximum H4H impact concentrations for each scenario are depicted in Appendix F. Model Impacts, Figures F-5 through F-8.

Table 4. Predicted Modeling Results omitting background monitor (µg/m³)

Model RUN	1 Hour SO_2 NAAQS µg/m³	H4H Maximum Receptor Impact µg/m³	H4H Watson Lane Receptor Impact µg/m³
mc_br01_nb	195.6	1120.78	984.74
mc_br01_emi_nb		503.82	471.59
mc_ar01_nb		154.7	143.29
mc_ar02_nb		106.7	98.84

***nb = no season-by-hour monitoring data**

The maximum H4H modeled impacts in micrograms per cubic meter (µg/m³) and parts per (ppb) billion are depicted in Appendix G. Predicted Modeled Impact Concentrations, Tables G-1 through G-4. It is worth mentioning that the predicted modeled H4H impact from Watson Lane monitor receptor in scenario mc_ar02_sshr and the annual 99th percentile (ppb) for the Watson Lane monitor for 2015 are similar. The predicted model impact is approximately 53 ppb compared to 56 ppb for the Watson Lane Monitor.

Blank

Appendix A. Aerial Maps

Figure A-1. Non-Attainment Boundary and Facility Orientation Pre-Construction

Figure A-2. Non-Attainment Boundary and Facility Orientation Post Construction

Figure A-3. Receptors mc_br01 and mc_br01_emi

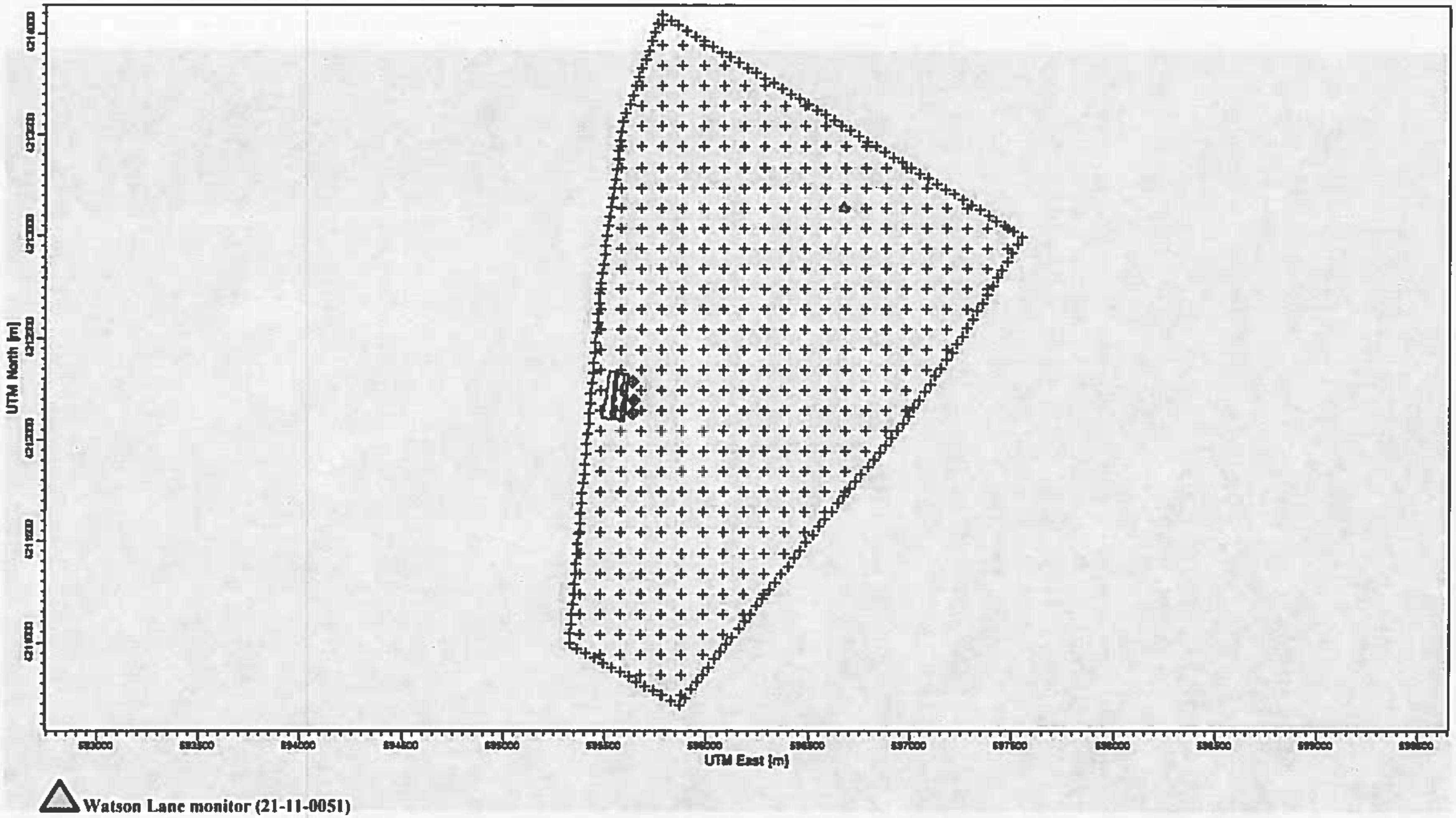
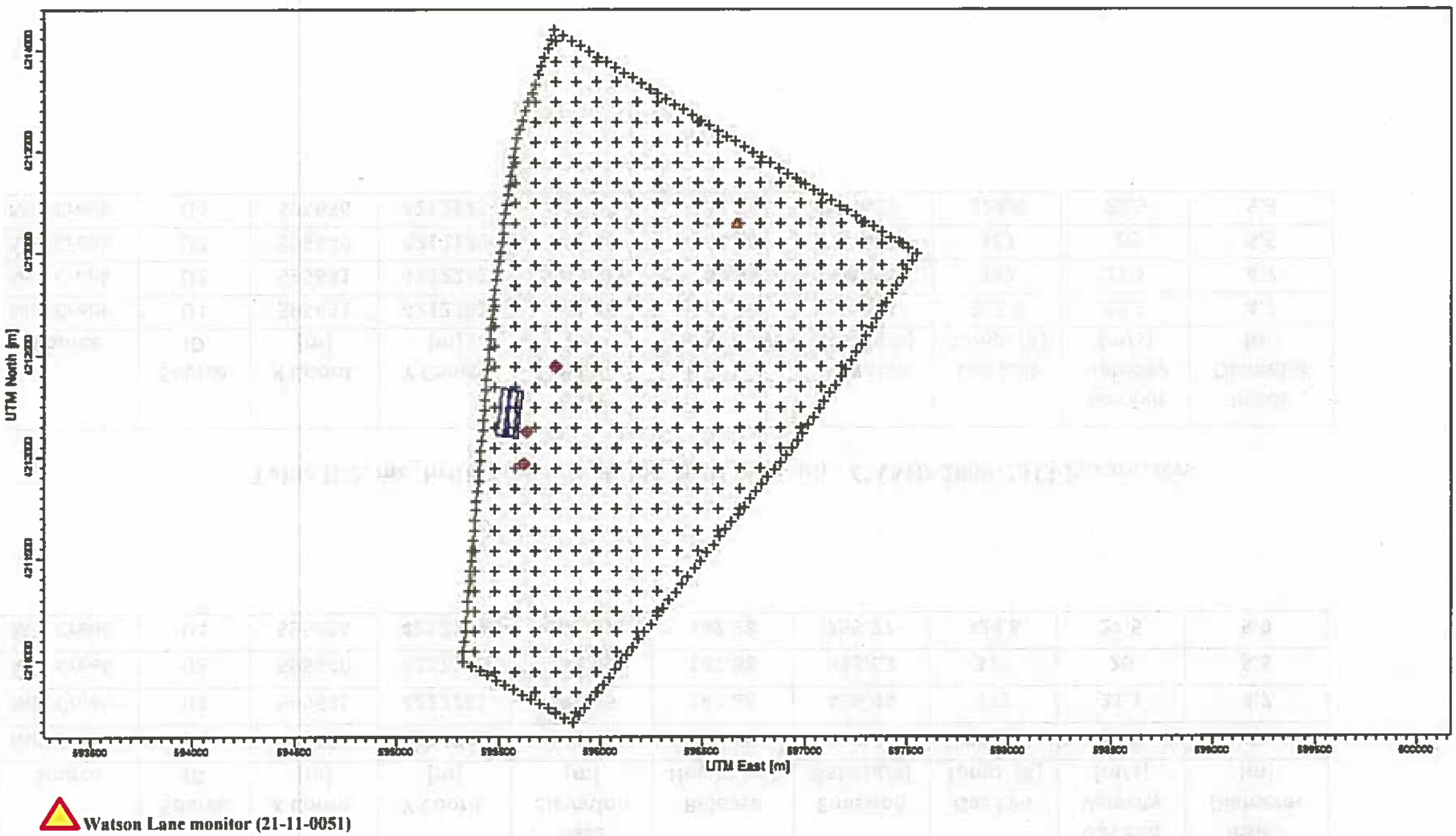


Figure A-4. Receptors mc_ar01 and mc_ar02



Appendix B. Emissions Source Parameters

Table B-1. mc_br01_sshr & mc_br01_nb - PTE 1.2 lb/MMBtu Parameters

Source	Source ID	X Coord. [m]	Y Coord. [m]	Base Elevation [m]	Release Height [m]	Emission Rate [g/s]	Gas Exit Temp. [K]	Gas Exit Velocity [m/s]	Inside Diameter [m]
Mill Creek	U1	595631	4212281	141.86	142.88	466.44	325.4	19.5	4.7
Mill Creek	U2	595631	4212281	141.86	142.88	466.44	327	21.1	4.7
Mill Creek	U3	595640	4212189	142.09	142.88	635.63	327	20	5.5
Mill Creek	U4	595636	4212125	141.97	142.88	759.77	324.8	22.5	5.9

Table B-2. mc_br01_emi_sshr & mc_br01_emi_nb - CAMD 2009-2013 Parameters

Source	Source ID	X Coord. [m]	Y Coord. [m]	Base Elevation [m]	Release Height [m]	Emission Rate [g/s]	Gas Exit Temp. [K]	Gas Exit Velocity [m/s]	Inside Diameter [m]
Mill Creek	U1	595631	4212281	141.86	142.88	CAMD	325.4	19.5	4.7
Mill Creek	U2	595631	4212281	141.86	142.88	CAMD	327	21.1	4.7
Mill Creek	U3	595640	4212189	142.09	142.88	CAMD	327	20	5.5
Mill Creek	U4	595636	4212125	141.97	142.88	CAMD	324.8	22.5	5.9

Table B-3. mc_ar01_sshr & mc_ar01_nb - Critical Value .29 lb/MMBtu Parameters

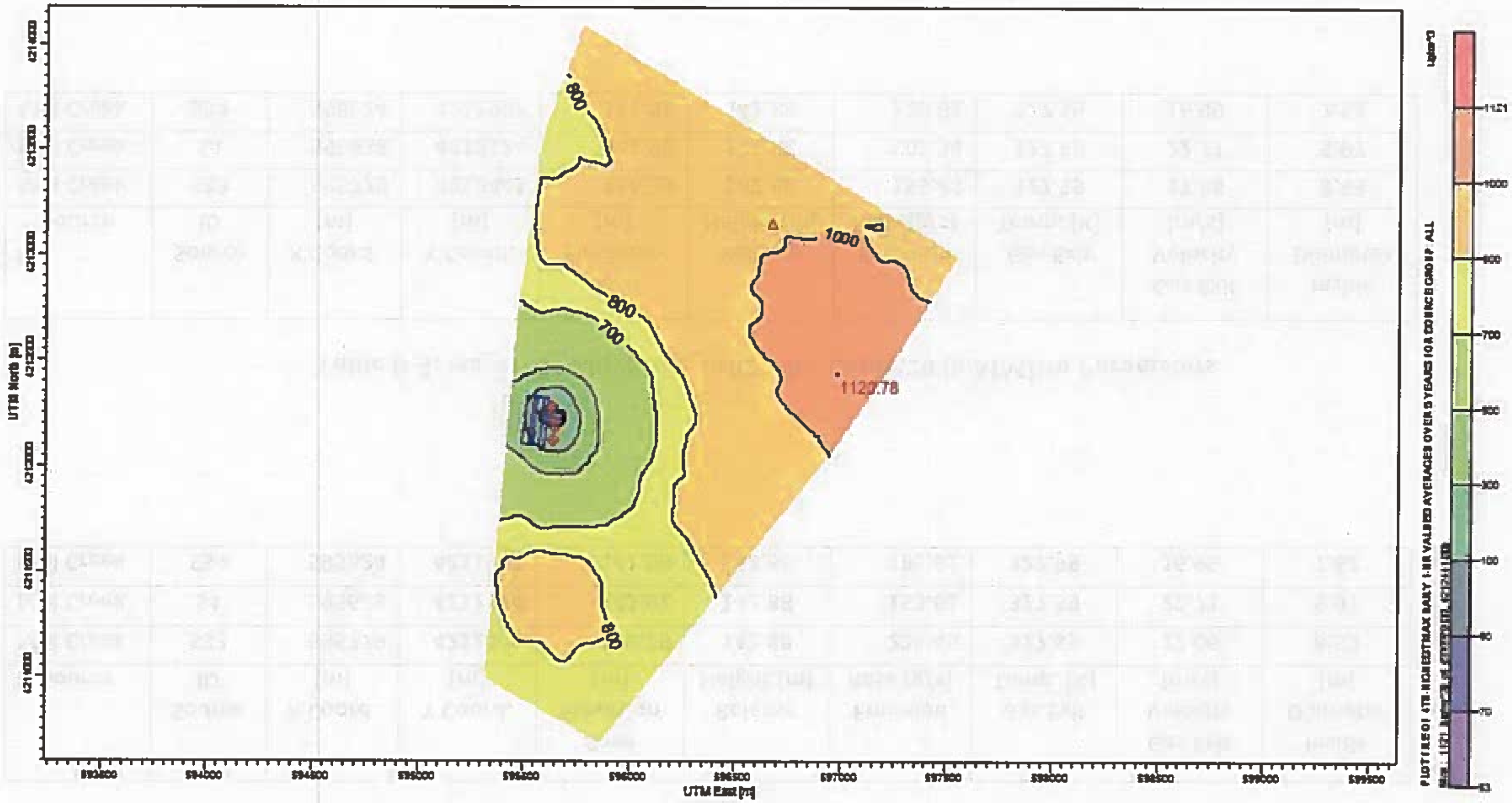
Source	Source ID	X Coord. [m]	Y Coord. [m]	Base Elevation [m]	Release Height [m]	Emission Rate [g/s]	Gas Exit Temp. [K]	Gas Exit Velocity [m/s]	Inside Diameter [m]
Mill Creek	S33	595779	4212441	136.29	142.88	225.45	327.59	17.06	8.53
Mill Creek	S4	595638	4212124	141.92	142.88	153.61	327.59	22.71	5.97
Mill Creek	S34	595624	4211967	141.98	142.88	183.61	327.59	16.99	7.62

Table B-4. mc_ar02_sshr & mc_ar02_nb - Limit .20 lb/MMBtu Parameters

Source	Source ID	X Coord. [m]	Y Coord. [m]	Base Elevation [m]	Release Height [m]	Emission Rate [g/s]	Gas Exit Temp. [K]	Gas Exit Velocity [m/s]	Inside Diameter [m]
Mill Creek	S33	595779	4212441	136.29	142.88	155.48	327.59	17.06	8.53
Mill Creek	S4	595638	4212124	141.92	142.88	105.94	327.59	22.71	5.97
Mill Creek	S34	595624	4211967	141.98	142.88	126.63	327.59	16.99	7.62

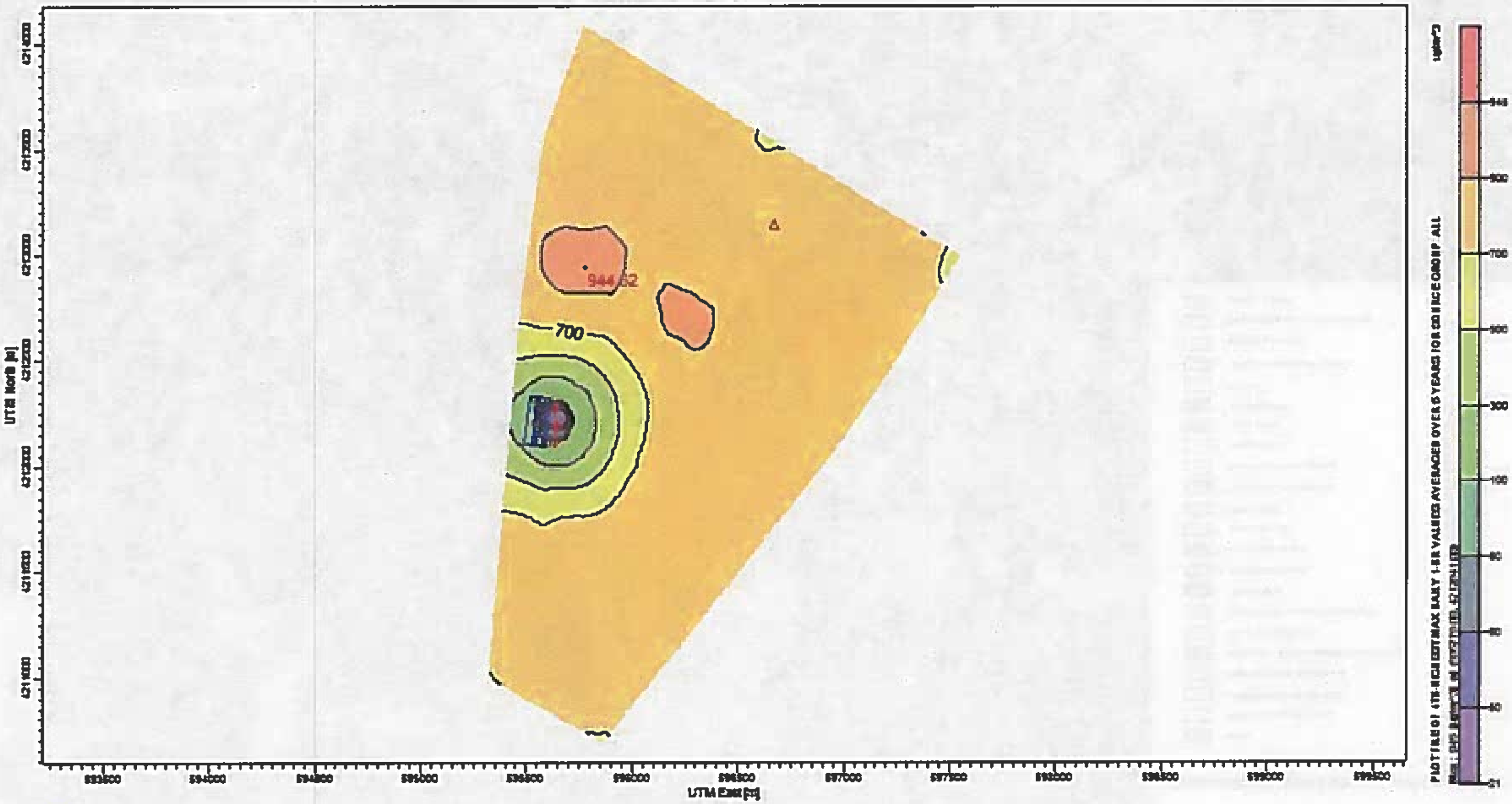
Appendix C. Meteorological Station Evaluation

Figure C-1. Standiford Field Meteorological Data, No Background at PTE 1.2 lb/MMBtu



Watson Lane monitor (21-11-0051)

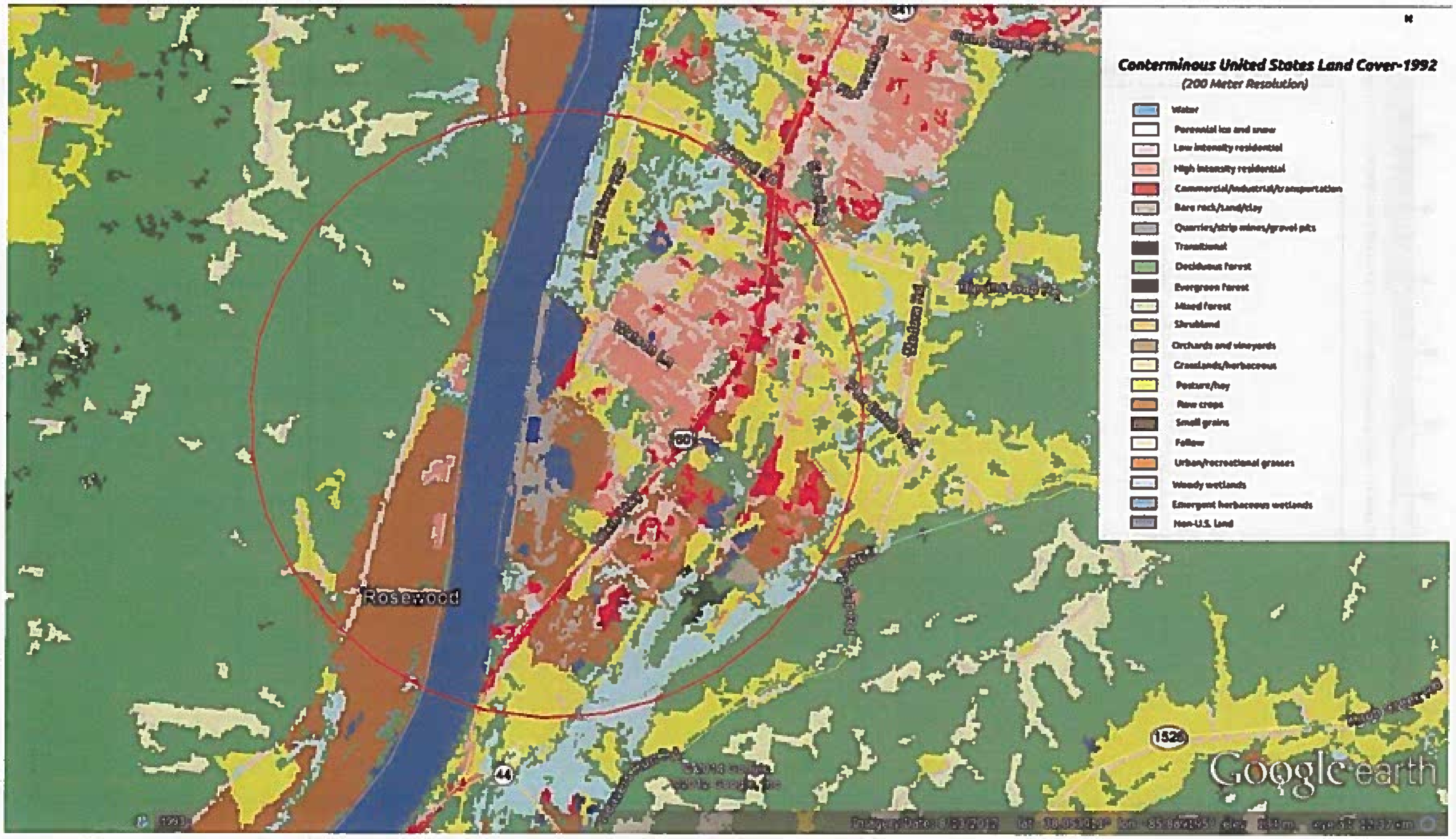
Figure C-2. Bowman Field Meteorological Data, No Background at PTE 1.2 lb/MMBtu



Watson Lane monitor (21-11-0051)

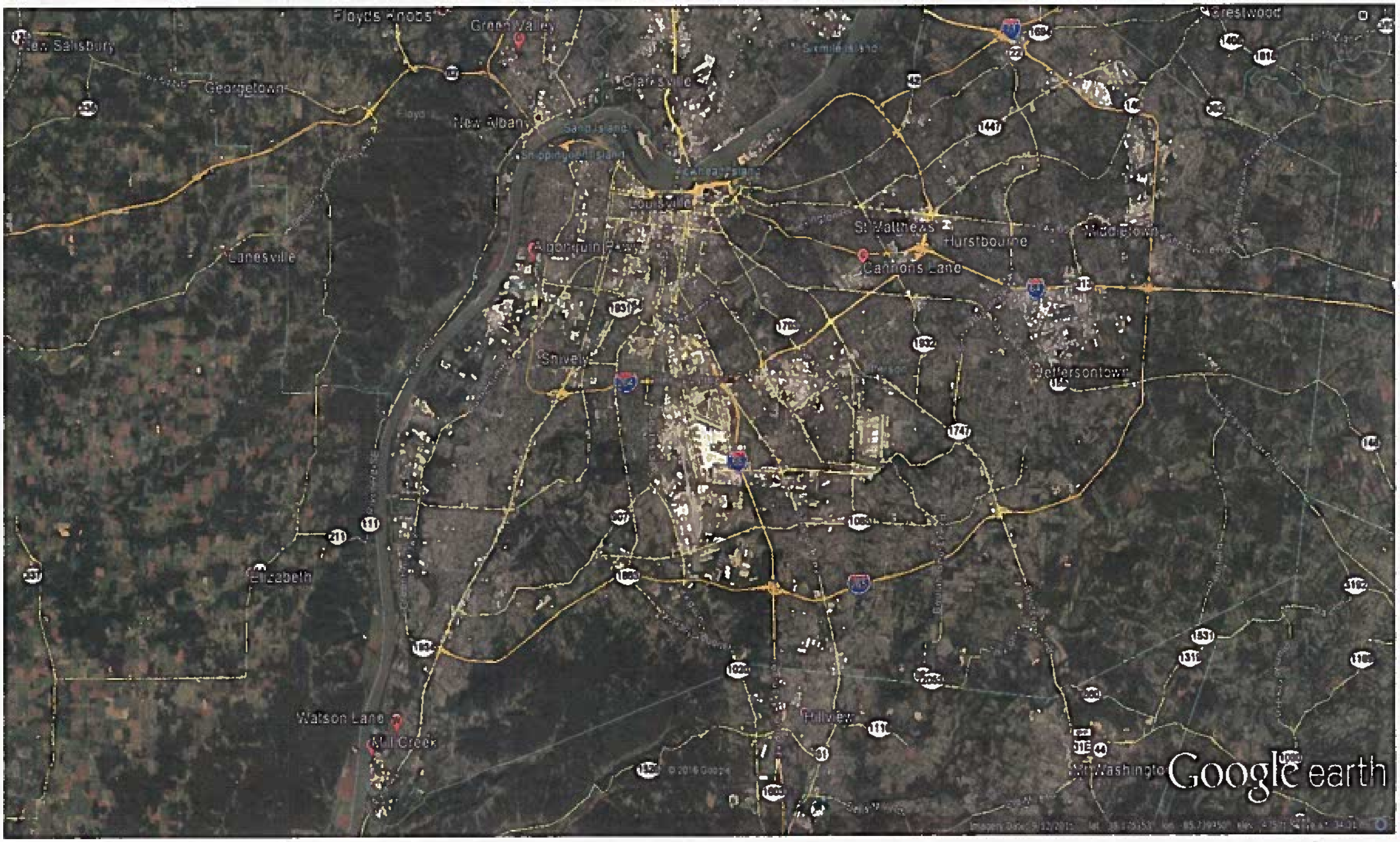
Appendix D. Dispersion Coefficient Analysis

Figure D-1. 3 km Circular Annotation, Aerial View



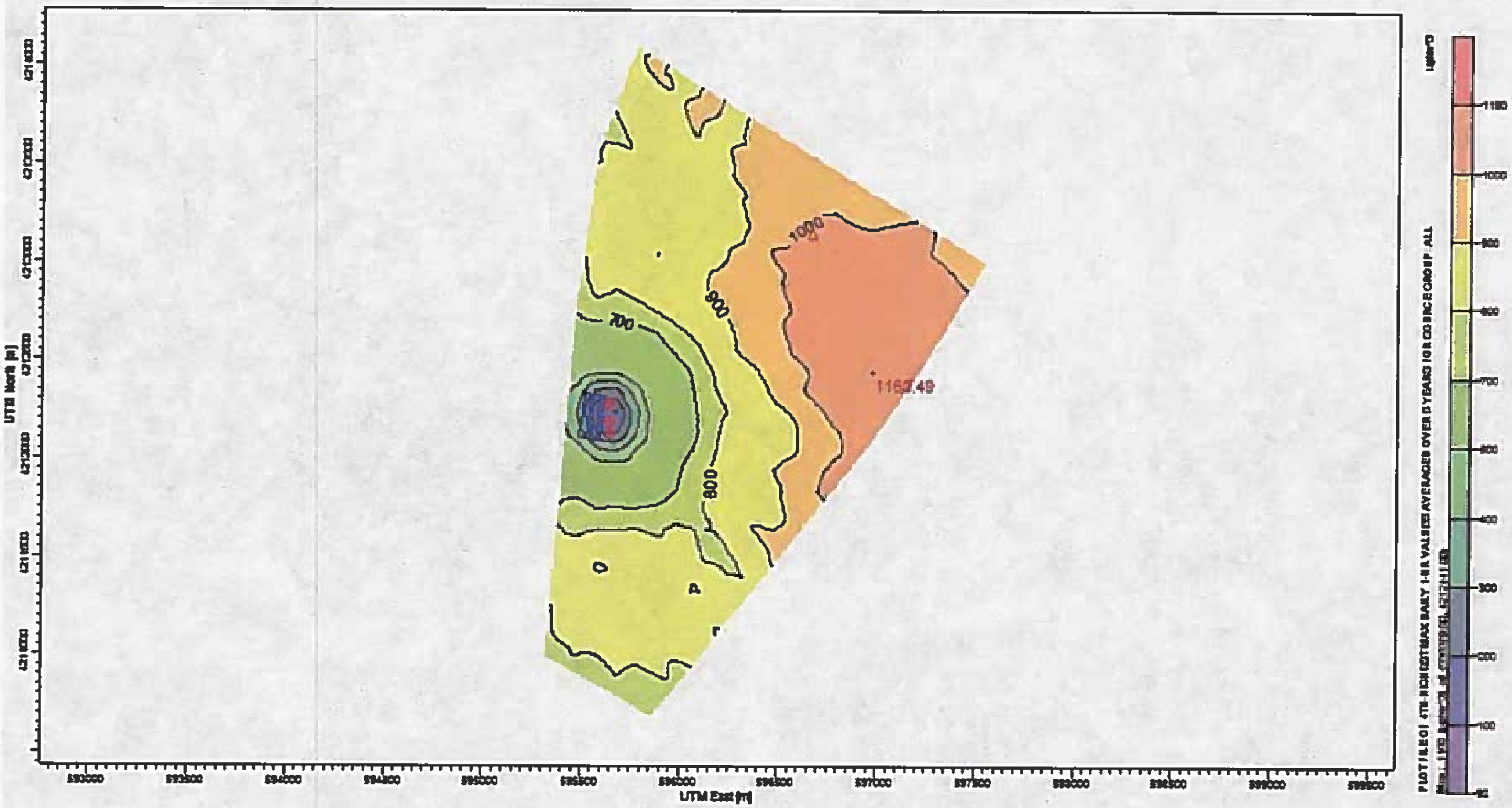
Appendix E. Monitoring Background Map

Figure E-1. SO_2 Monitor Locations



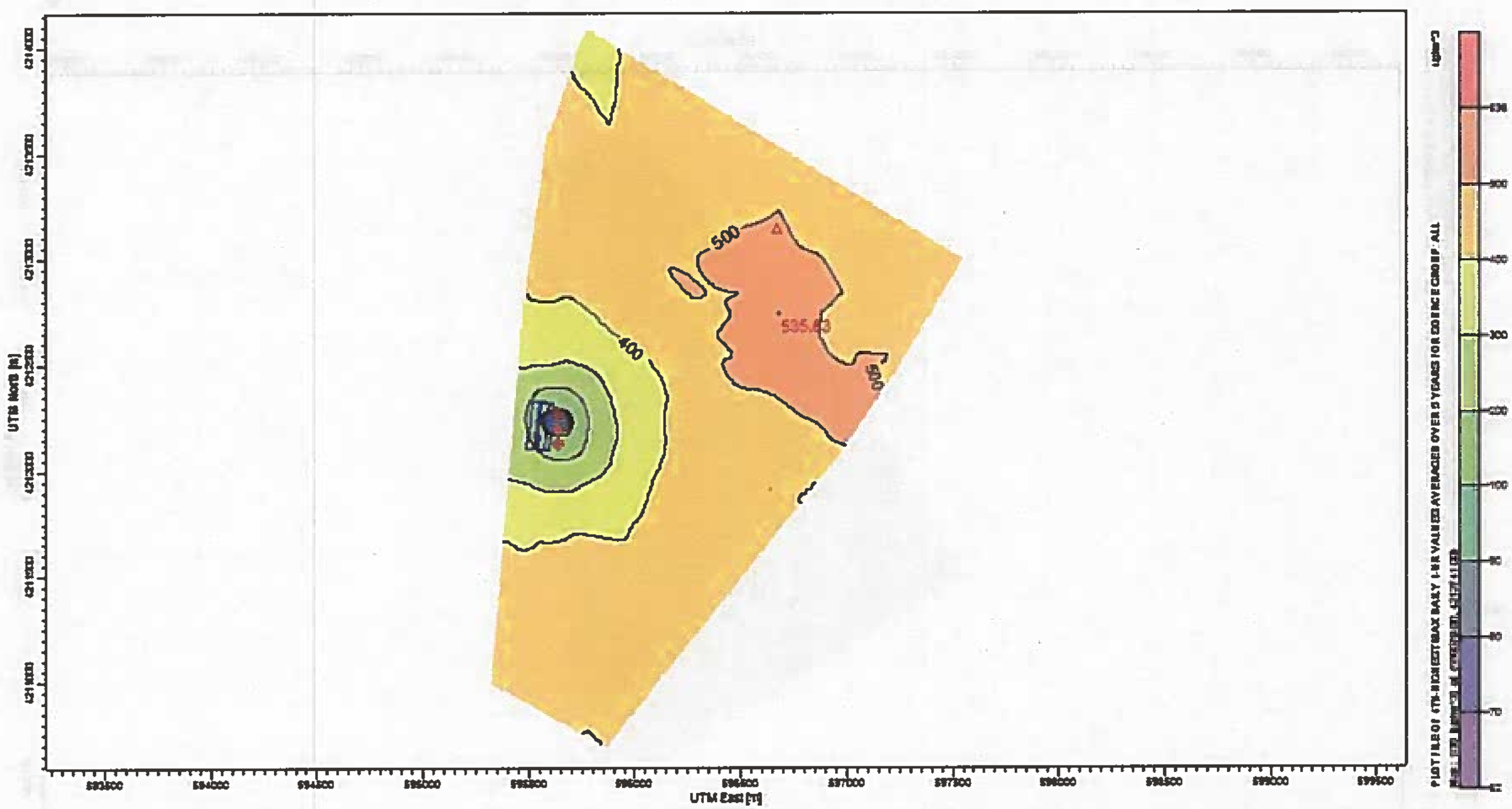
Appendix F. Model Impacts

Figure F-1. mc_br01_sshr PTE 1.2 lb/MMBtu High 4th High Maximum Impact



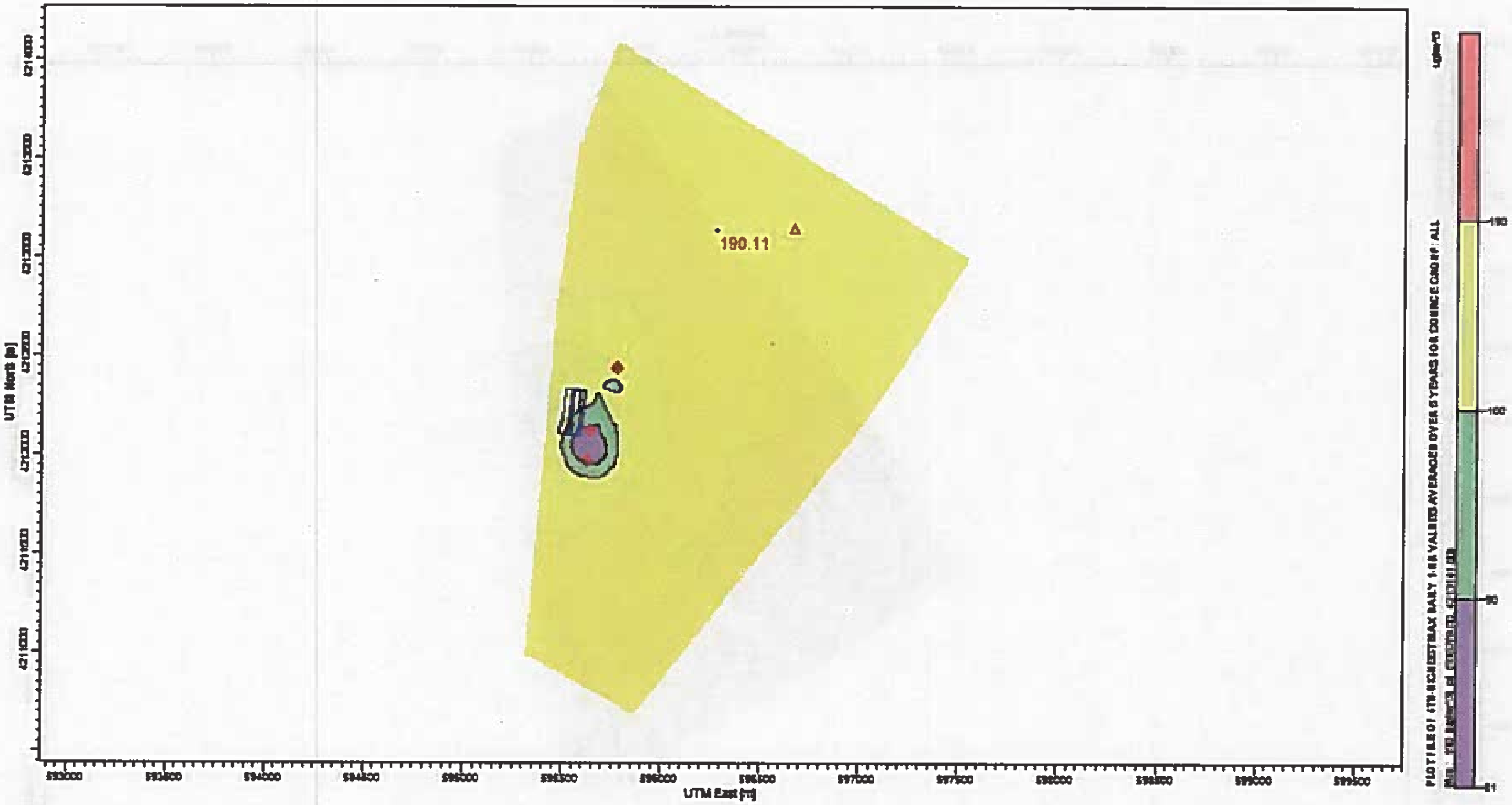
Watson Lane monitor (21-11-0051) = 1023.83 $\mu g/m^3$

Figure F-2. mc_br01_emi_sshr CAMD High 4th High Maximum Impact



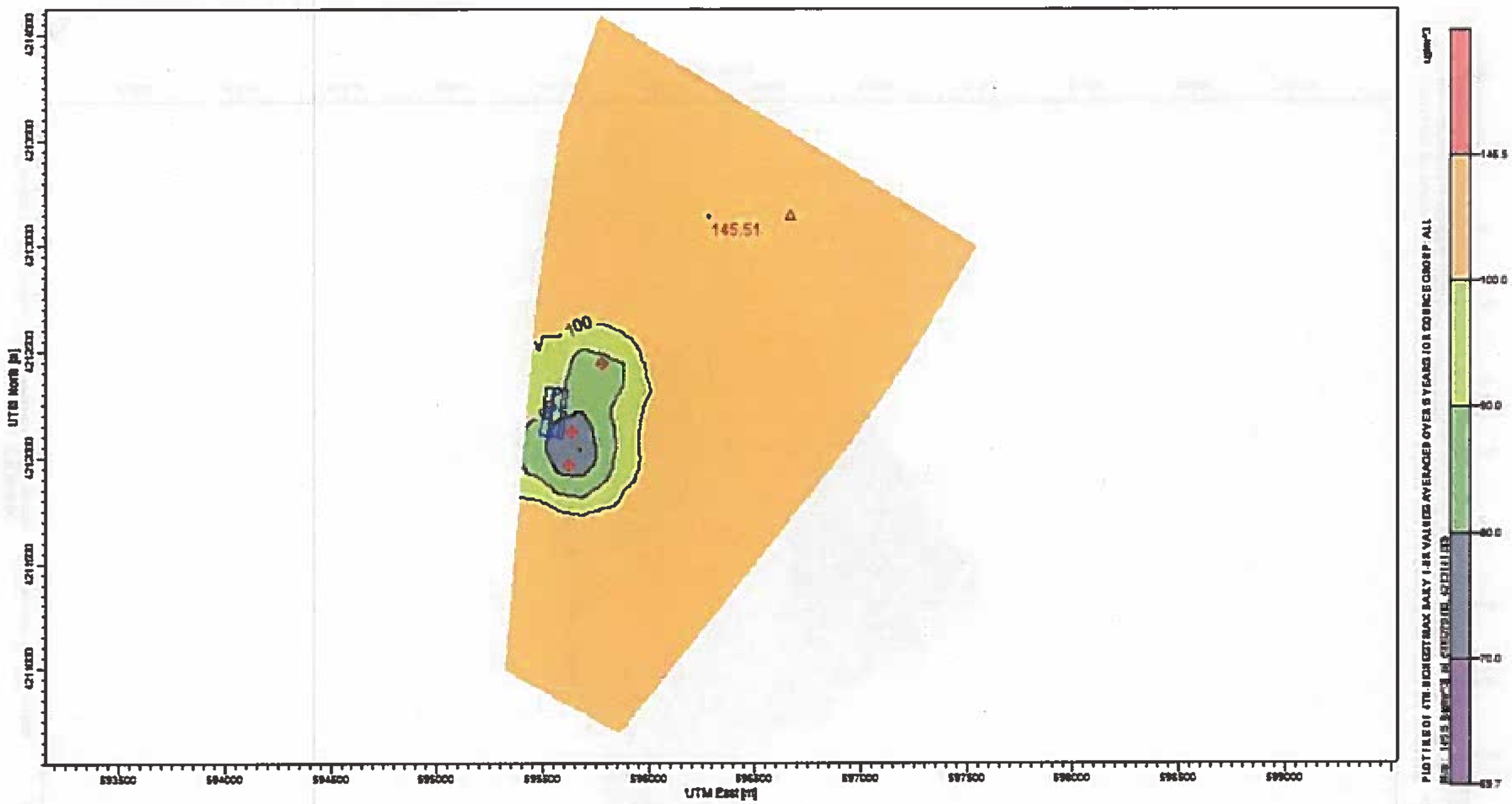
Watson Lane monitor (21-11-0051) = 508.87 μg/m³

Figure F-3. mc_ar01_sshr Critical Value .29 lb/MMBtu High 4th High Maximum Impact



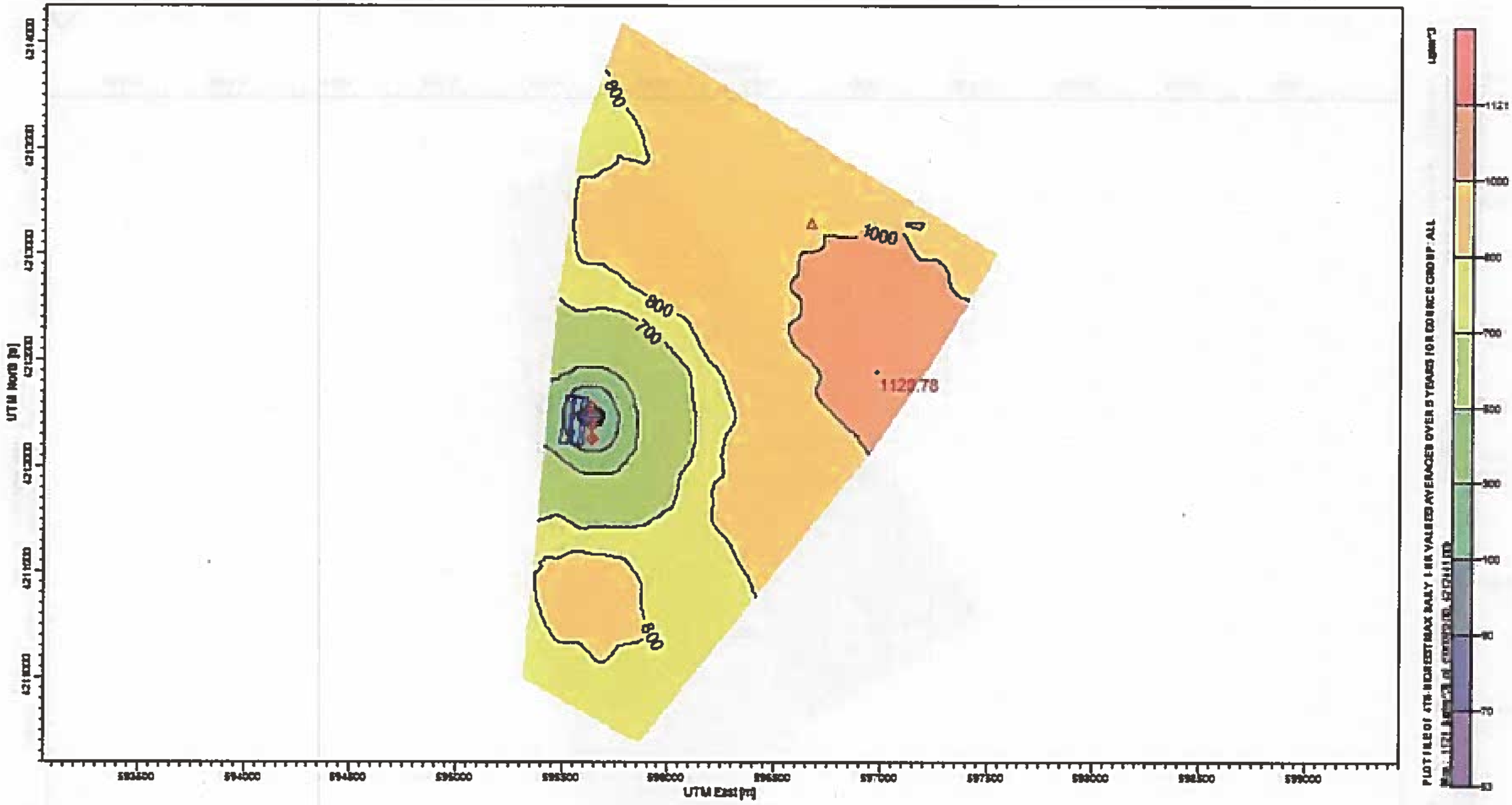
Watson Lane monitor (21-11-0051) = 184.37 µg/m³

Figure F-4. mc_ar02_sshr Limit .20 lb/MMBtu High 4th High Maximum Impact



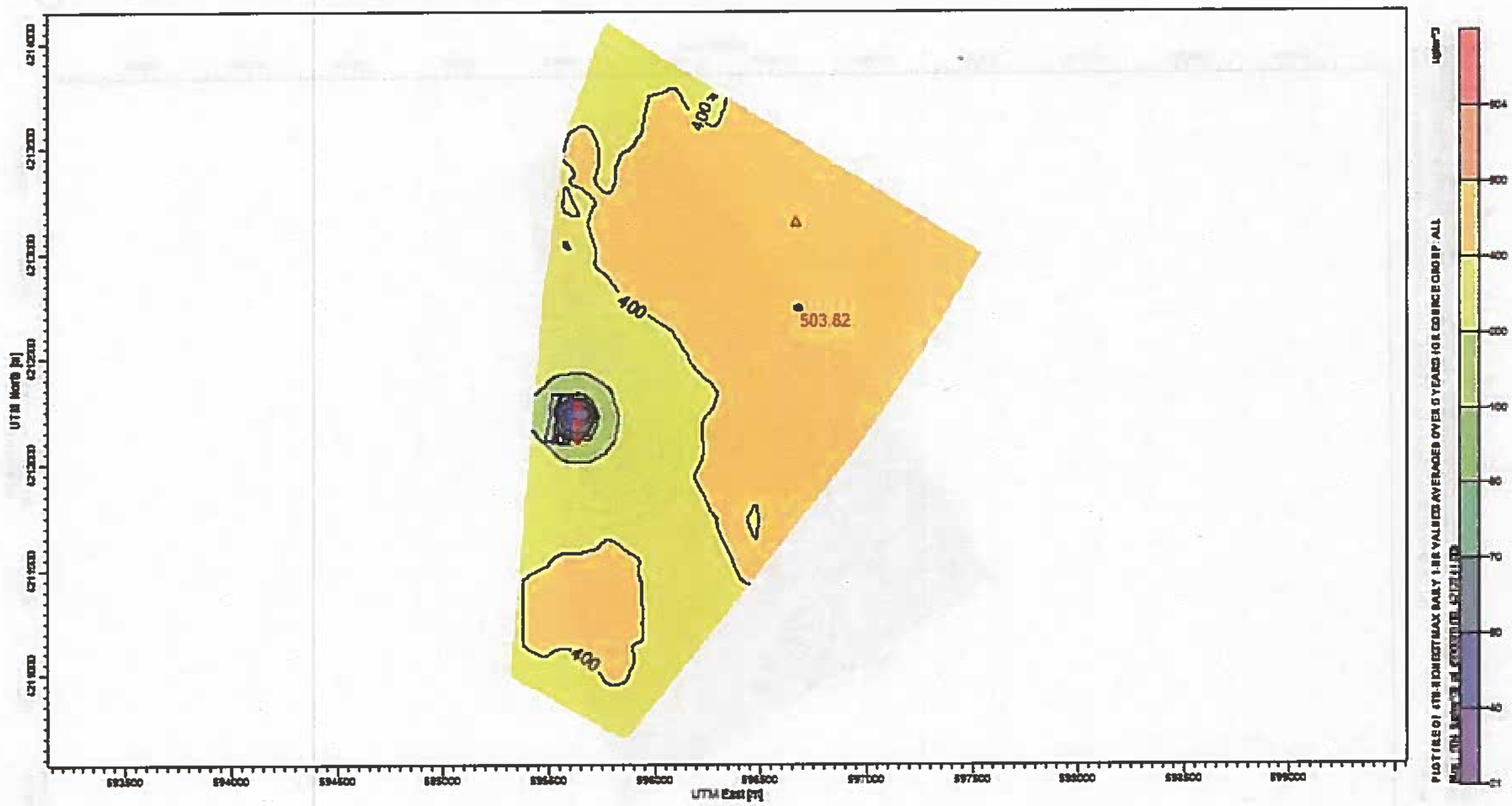
Watson Lane monitor (21-11-0051) = 140.14 μg/m³

Figure F-5. mc_br01_nb - PTE 1.2 lb/MMBtu High 4th High Maximum Impact



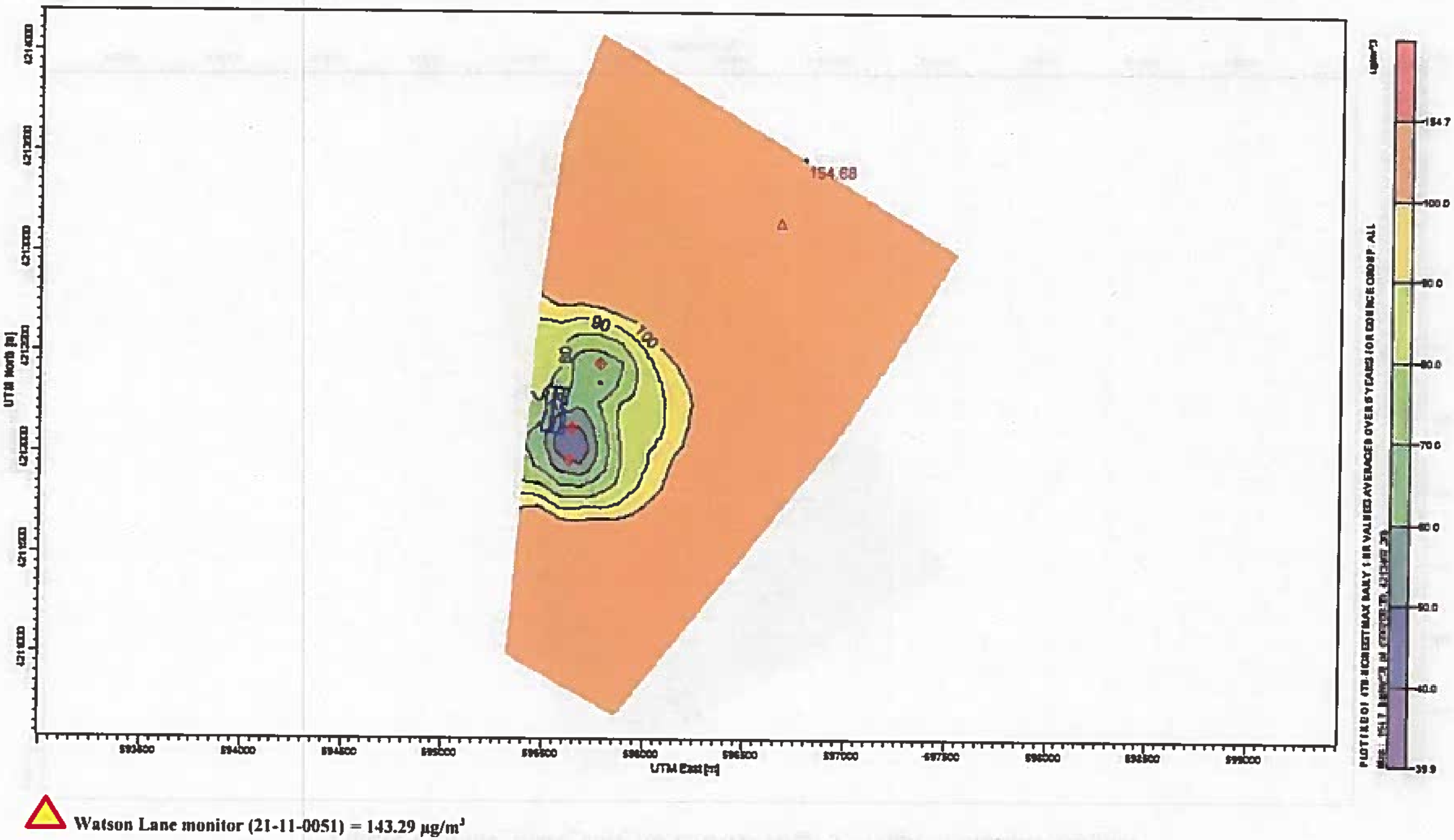
Watson Lane monitor (21-11-0051) = 984.74μg/m³

Figure F-6. mc_br01_emi_nb CAMD High 4th High Maximum Impact



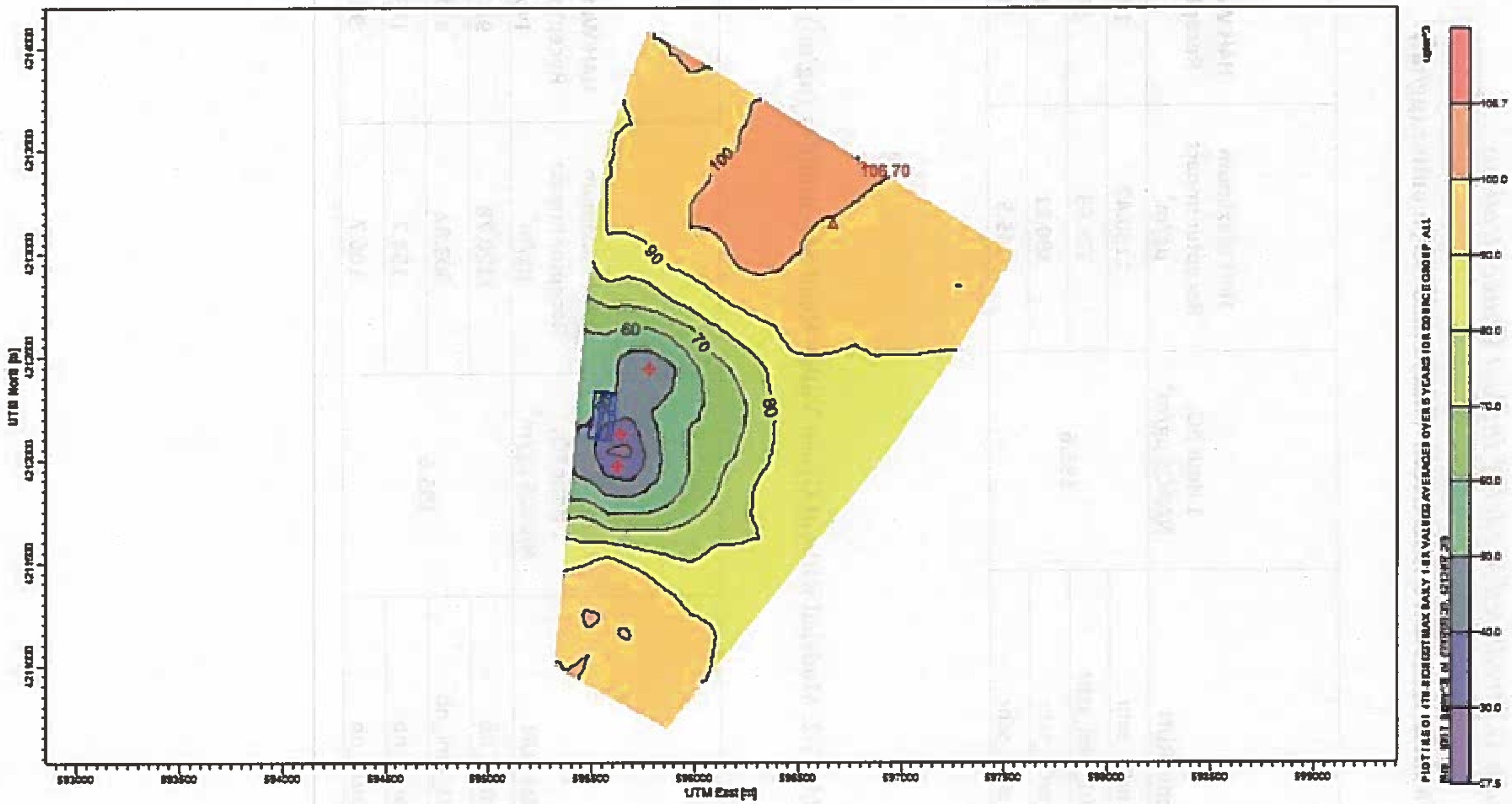
Watson Lane monitor (21-11-0051) = 471.59 μg/m³

Figure F-7. mc_ar01_nb Critical Value .29 lb/MMBtu High 4th High Maximum Impact



Watson Lane monitor (21-11-0051) = 143.29 μg/m³

Figure F-8. mc_ar02_nb Limit .20 lb/MMBtu High 4th High Maximum Impact



Watson Lane monitor (21-11-0051) = 98.84 μg/m³

Appendix G. Predicted Modeled Impact Concentrations

Table G-1. Modeled with Green Valley Road SO_2 monitor ($\mu g/m^3$)

Model RUN	1 Hour SO_2 NAAQS $\mu g/m^3$	H4H Maximum Receptor Impact $\mu g/m^3$	H4H Watson Lane Receptor Impact $\mu g/m^3$
mc_br01_sshr	195.6	1160.49	1023.83
mc_br01_emi_sshr		535.63	508.87
mc_ar01_sshr		190.11	184.37
mc_ar02_sshr		145.5	140.14

Table G-2. Modeled without Green Valley Road SO_2 monitor ($\mu g/m^3$)

Model RUN	1 Hour SO_2 NAAQS $\mu g/m^3$	H4H Maximum Receptor Impact $\mu g/m^3$	H4H Watson Lane Receptor Impact $\mu g/m^3$
mc_br01_nb	195.6	1120.78	984.74
mc_br01_emi_nb		503.82	471.59
mc_ar01_nb		154.7	143.29
mc_ar02_nb		106.7	98.84

Table G-3. Modeled with Green Valley Road SO_2 monitor (ppb)

Model RUN	1 Hour SO_2 NAAQS ppb	H4H Maximum Receptor Impact µg/m³	H4H Watson Lane Receptor Impact µg/m³
mc_br01_sshr	75	443	391
mc_br01_emi_sshr		204	194
mc_ar01_sshr		73	70
mc_ar02_sshr		56	53

Table G-4. Modeled without Green Valley Road SO_2 monitor (ppb)

Model RUN	1 Hour SO_2 NAAQS ppb	H4H Maximum Receptor Impact µg/m³	H4H Watson Lane Receptor Impact µg/m³
mc_br01_nb	75	428	376
mc_br01_emi_nb		192	180
mc_ar01_nb		59	55
mc_ar02_nb		41	38

Additional Information Index

```
Directory of E:\Mill Creek Files

12/29/1899  07:00 PM    <DIR>          .
12/29/1899  07:00 PM    <DIR>          ..
01/19/2017  12:19 PM        62,294,417 mc_ar01.rar
01/19/2017  12:21 PM        61,976,888 mc_ar02.rar
01/19/2017  12:30 PM        69,515,001 mc_br01.rar
01/19/2017  12:37 PM        62,752,617 mc_br02_emi.rar
01/19/2017  12:47 PM        59,938,540 mc_station_eval.rar
01/19/2017  03:49 PM       233,492,641 Met.rar
01/19/2017  03:51 PM        13,925,539 Misc.rar
01/19/2017  12:50 PM        95,390,857 NED.rar
               8 File(s)    659,286,500 bytes

     Total Files Listed:
               8 File(s)    659,286,500 bytes
               3 Dir(s)               0 bytes free
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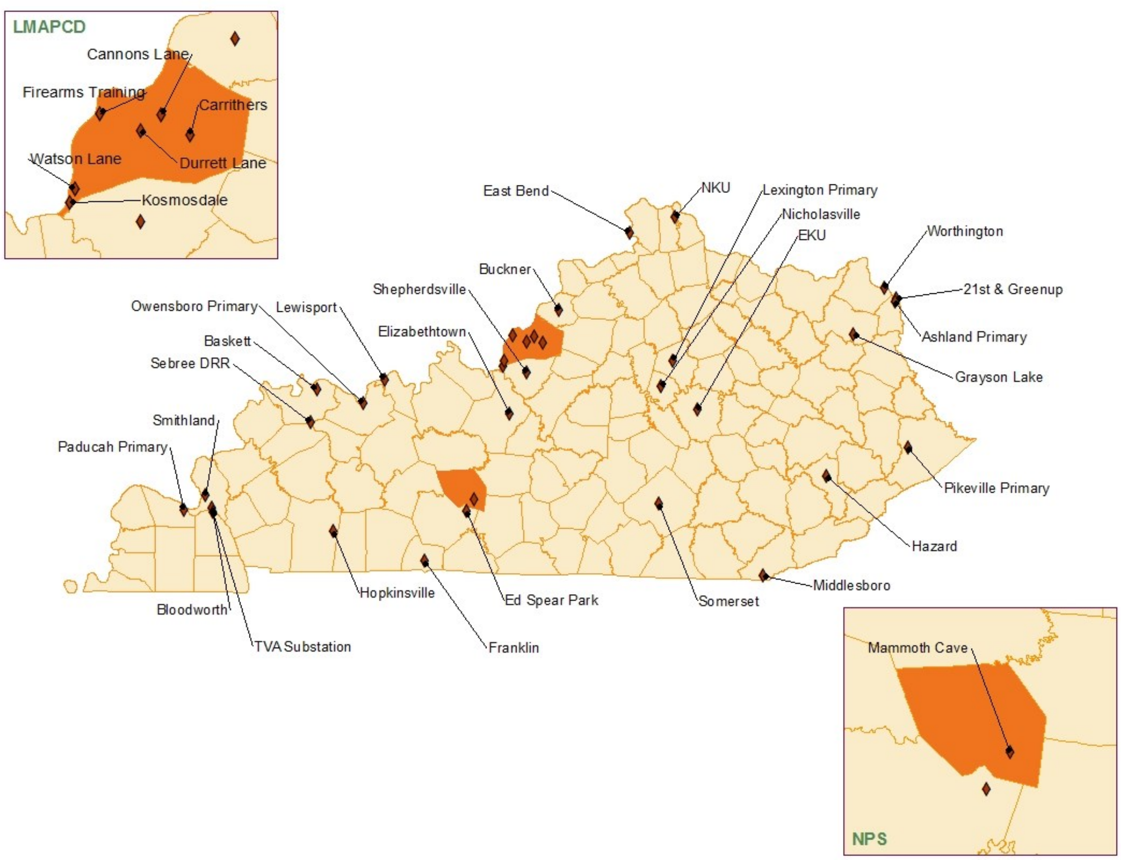
Appendix B

Kentucky Annual Ambient Air Monitoring Network Plan - 2018

Kentucky
Annual Ambient Air Monitoring Network Plan 2018



Commonwealth of Kentucky Energy & Environment Cabinet
Department for Environmental Protection
Division for Air Quality
300 Sower Boulevard
Frankfort, Kentucky 40601

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CERTIFICATION

By the signatures below, the Kentucky Division for Air Quality certifies that the information contained in this Surveillance Network document for sampling year 2018 is complete and accurate at the time of submittal to EPA Region 4. However, due to circumstances that may arise during the sampling year, some network information may change. A notification of change and a request for approval will be submitted to EPA Region 4 at that time, following a 30-day public comment period.

Print Name:	Shauna L. Switzer Environmental Scientist V	Signature:	Shauna Switzer	Date:	6/27/18
Print Name:	Jennifer F. Miller Technical Services Branch Manager	Signature:	Jennifer F. Miller	Date:	6-27-18
Print Name:	Sean O. Alteri Division Director	Signature:	Sean Alteri	Date:	6/27/18

PUBLIC NOTIFICATION AND COMMENT PERIOD

In accordance with 40 C.F.R. 58.10(a)(1), the Kentucky Energy and Environment Cabinet shall make the annual monitoring network plan available for public inspection for at least 30 days prior to submission to the US EPA. The annual monitoring network plan details the operation and location of ambient air monitors operated by the Kentucky Division for Air Quality (KDAQ), Louisville Metro Air Pollution Control District (LMAPCD), and the National Park Service (NPS).

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ACRONYMS

AEM – Automated Equivalent Method

AQI – Air Quality Index

AQS – Air Quality System

ARM – Automated Reference Method

CBSA – Core-Based Statistical Area

CSA – Combined Statistical Area

CO – Carbon Monoxide

DRR – Data Requirements Rule

FAM – Federal Alternate Method

FEM – Federal Equivalent Method

FRM – Federal Reference Method

KDAQ – Kentucky Division for Air Quality

LMAPCD – Louisville Metro Air Pollution Control District

MSA – Metropolitan Statistical Area

NAAQS – National Ambient Air Quality Standards

NAMS – National Air Monitoring Stations

NAREL– National Air and Radiation Environmental Laboratory

NATTS – National Air Toxics Trends Stations

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NIST– National Institute of Standards and Technology

NO_2 – Nitrogen Dioxide

NPS – National Park Service

O_3 – Ozone

PAH – Polycyclic Aromatic Hydrocarbons

Pb – Lead

PM – Particulate Matter

PTFE-Polytetrafluoroethylene

PWEI – Population Weighted Emissions Index

RA-40 – Regional Administrator 40

SAMWG – Standing Air Monitoring Working Group

SLAMS – State and Local Air Monitoring Stations

SO_2 – Sulfur Dioxide

SPM – Special Purpose Monitors

TBD – To Be Determined

TEOM – Tapered Elemental Oscillating Microbalance

U.S. EPA – United States Environmental Protection Agency

VOC – Volatile Organic Compounds

INTRODUCTION

INTRODUCTION

The Kentucky Division for Air Quality (KDAQ) has operated an air quality monitoring network in the Commonwealth since July 1967. The Louisville Metro Air Pollution Control District (LMAPCD), a local agency, has maintained a sub-network in its area of jurisdiction since January 1956. Since that time, the networks have been expanded in accordance with United States Environmental Protection Agency's (US EPA) regulations.

In October 1975, the US EPA established a work group to critically review and evaluate current air monitoring activities at that time. This group was named the Standing Air Monitoring Working Group (SAMWG). The review by the SAMWG indicated several areas where deficiencies existed which needed correction. The principal areas needing correction were: an excess of monitoring sites in some areas to assess air quality; existing regulations that did not allow for flexibility to conduct special purpose monitoring studies; and data reporting that was untimely and incomplete. These deficiencies were primarily caused by a lack of uniformity in station locations and probe siting, sampling methodology, quality assurance practices, and data handling procedures.

In August 1978, recommendations developed by SAMWG, to remedy the deficiencies in the existing monitoring activities, were combined with the new requirements of Section 319 of the Clean Air Act. Section 319 provided for the development of uniform air quality monitoring criteria and methodology; reporting of a uniform air quality index in major urban areas; and the establishment of an air quality monitoring system nationwide which utilized uniform monitoring criteria and provides for monitoring stations in major urban areas that supplement State monitoring. The combination of the recommendations and requirements were included in a proposed revision to the air monitoring regulations.

In May 1979, air monitoring regulations were finalized by the US EPA requiring certain modifications and additions to be included in the State Implementation Plan for air quality surveillance. These regulations require each state to operate a network of monitoring stations designated as State and Local Air Monitoring Stations (SLAMS) that measure ambient concentrations of air pollutants for which standards have been established. The SLAMS designation contains provisions concerning the conformity to specific siting and monitoring criteria not previously required. The regulations also provide for an annual review of the monitoring network to insure objectives are being met and to identify needed modification.

The current overall network consists of 34 air monitoring stations, operated by KDAQ, LMAPCD, and the National Park Service (NPS). The Commonwealth's SLAMS air monitoring network monitors criteria pollutants for which the National Ambient Air Quality Standards (NAAQS) have been issued. In addition to a SLAMS network, KDAQ's air monitoring network includes special purpose monitors (SPM) for air toxics and meteorological data.

The annual monitoring network description, as provided for in 40 CFR Part 58.10, *Annual monitoring network plan and periodic network assessment*, must contain the following information for each monitoring station in the network:

1. The Air Quality System (AQS) site identification number for existing stations.

2. The location, including the street address and geographical coordinates, for each monitoring station.

3. The sampling and analysis method used for each measured parameter.

4. The operating schedule for each monitor.

5. Any proposal to remove or move a monitoring station within a period of eighteen months following the plan submittal.

6. The monitoring objective and spatial scale of representativeness for each monitor.

7. The identification of any site that is suitable for comparison against the $PM_{2.5}$ NAAQS.

8. The Metropolitan Statistical Area (MSA), Core-Based Statistical Area (CBSA), Combined Statistical Area (CSA), or other area represented by the monitor.

The following document constitutes the Kentucky ambient air monitoring network description and is organized into main parts:

1. Station Description Format: An outline of the designations, parameters, monitoring methods, and the basis for site selection.

2. Network Summaries: Presenting the total number of sites and monitors in each region and for the state. Also included is a listing of all proposed changes to the current network.

3. Air Monitoring Station Description: Each air monitor station is described in detail as per the outline in (1) above.

4. Appendices: Additional information relating to the ambient air monitoring network.

<u>Modification to the network as determined by an annual review process will be made each year to maintain a current network description document.</u>

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AIR MONITORING NETWORK SUMMARY

SUMMARY OF KDAQ NETWORK CHANGES 2018

During the 2018-2019 monitoring year, KDAQ will operate 94 instruments, including 11 meteorological stations, located at 27 ambient air monitoring sites in 24 Kentucky counties. LMAPCD will operate an additional 33 instruments, including 6 meteorological stations, in Jefferson County. When combined with the air monitoring site operated by the National Park Service NPS at Mammoth Cave National Park, the total ambient air monitoring network will consist of 133 instruments, including 18 meteorological stations, located at 34 sites across 26 counties of the Commonwealth.

KDAQ proposes to make the changes below to the ambient air monitoring network. Changes to the LMAPCD network are detailed in Appendix E.

METROPOLITAN STATISTICAL AREAS (MSAs):

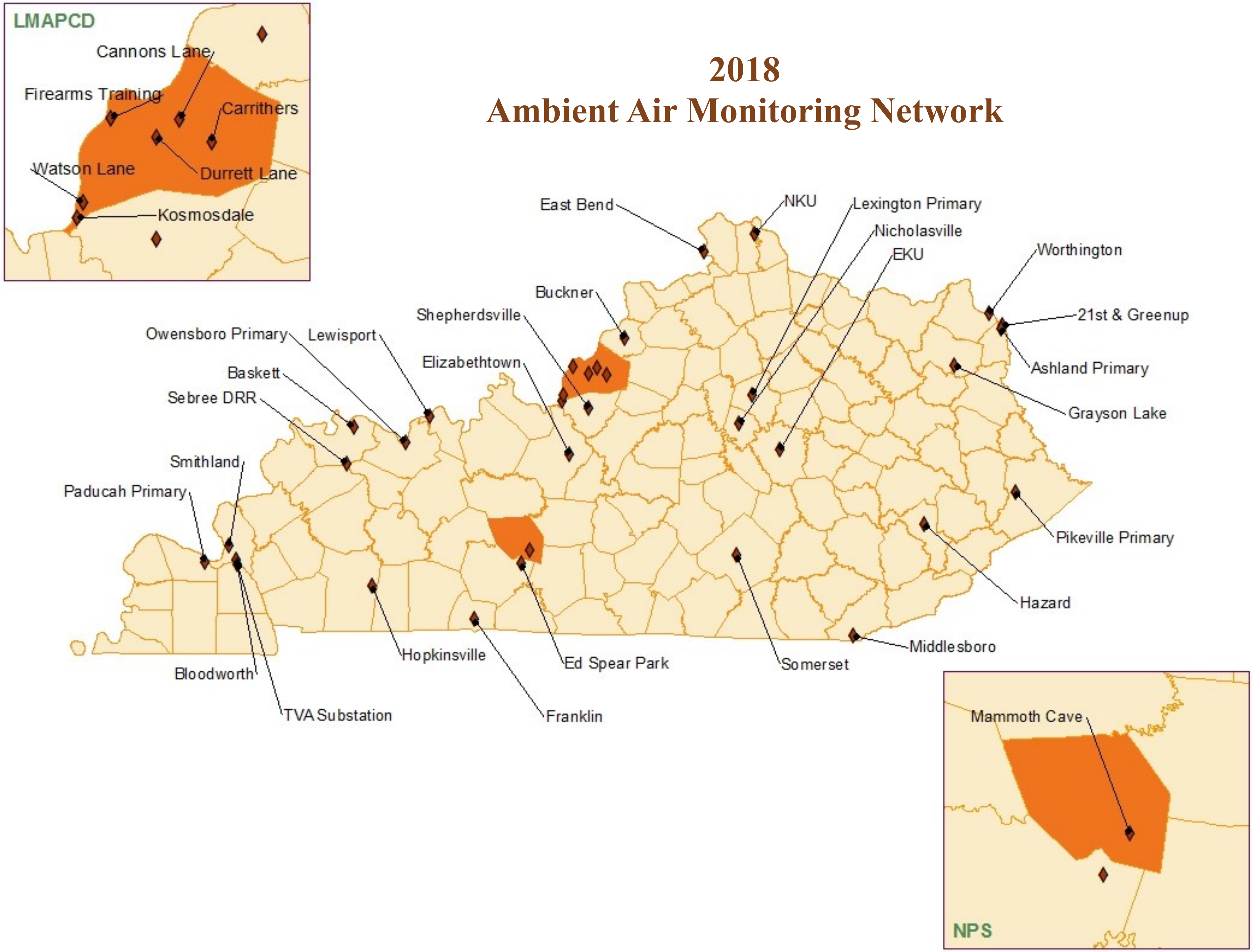
- Huntington-Ashland, WV-KY-OH:
    - Permanently discontinue special-purpose VOC sampling at the Ashland Primary site (21-019-0017); effective December 31, 2018.

2018 AIR MONITORING STATIONS SUMMARY

Metropolitan Statistical Area	Site Count	$PM_{2.5}$	Continuous $PM_{2.5}$	PM_{10}	Continuous PM_{10}	SO_2	NO_2	NO_y	CO	O_3	Pb	VOC	Carbonyl	PAH	$PM_{2.5}$ Speciation	Carbon Speciation	RadNet	Met
Bowling Green, KY	2	2^{C}	2^{i}			1		1	1	$2^{i, Max}$								1
Cincinnati-Middletown, OH-KY-IN (AQI) (PWEI)	2	2^{c}	$1^{i,S}$			1^{i}	1^{i}			2^{i}								1
Clarksville, TN-KY	1	1^{X}								1								1
Elizabethtown, KY	1	2^{C}	1							1^{Max}								
Evansville, IN-KY (PWEI)	2	1	1^{S}	1^{m}		2^{DRR}				1^{Max}								
Huntington-Ashland, WV-KY-OH (AQI) (PWEI)	3	1	$1^{i, S}$	$2^{C,m}$		2^{i}	1^{i}			$2^{i, Max}$								1
Lexington-Fayette, KY (AQI) (PWEI)	2	1	1^{i}	1^{m}		2^{i}	$1^{r40,i}$			$2^{i, Max}$							1	1
Louisville-Jefferson County, KY-IN (AQI) (PWEI)	8	$3^{n,C}$	$5^{i,S}$		$2^{i,,S,}$	4^{i}	$2^{n,i}$	1	$2^{n,i}$	$5^{i, Max}$		2^{G}			1	1	1	7^{n}
Owensboro, KY	2	1	$1^{i,S}$			1^{i}	1^{i}			$2^{i, Max}$								1
Micropolitan Statistical Area																		
Paducah, KY-IL (PWEI)	3	1	$1^{i,S}$	2^{m}		1^{i}	1^{i}			2^{i}		1					1	1
Somerset, KY	1	1								1								
Middlesboro, KY	1	1								1								1
Richmond-Berea, KY	1										2^{C}							
Not in a CBSA																		
Carter County	1	1^{X}		$2^{C,m}$						1		2^{D}	2^{D}	1				1
Marshall County	1											2^{C}						
Perry County	1	1	1							1								1
Pike County	1	1	1^{i}							1^{i}								
Simpson County	1									1								1
KDAQ Totals	27	17	10	8	0	9	5	0	0	22	2	5	2	1	0	0	2	11
LMAPCD Totals	6	3	5	0	2	4	2	1	2	3	0	2	0	0	1	1	1	6
NPS Totals	1	0	1	0	0	1	0	1	1	1	0	0	0	0	0	0	0	1
Total Network	**34**	**20**	**16**	**8**	**2**	**14**	**7**	**2**	**3**	**26**	**2**	**7**	**2**	**1**	**1**	**1**	**3**	**18**

Tallies are equal to the actual number of monitors present. Superscripts represent additional information about the network. PWEI= PWEI SO2 Monitoring Required in MSA; r40=RA-40 Monitor; Max= Maximum O_3 Concentration Site; n=Near-Road Monitor; X= Regional $PM_{2.5}$ Transport or Background Monitor; S=Continuous PM T640; AQI=AQI Monitoring Required in CBSA; i=AQI Reported; m= PM10 Filter Analyzed for Metals; G=Continuous Auto-GC; C=Collocated Monitors ; D= Duplicate Channels; DRR= SO2 Data Requirements Rule Monitor

2018
Ambient Air Monitoring Network



STATION DESCRIPTION FORMAT

STATION DESCRIPTION FORMAT

AQS Site Identification Information

Pertinent, specific siting information for each site and monitor is stored in the US EPA's AQS data system. This information includes the exact location of the site, local and regional population, description of the site location, monitor types, and monitoring objectives. This site and monitor information is routinely updated whenever there is a change in site characteristics or pollutants monitored.

Network Station Description

The network station descriptions contained in this document include the following information:

1. Site Description

Specific information is provided to show the location of the monitoring equipment at the site, the CBSA in which the site is located, the AQS identification number, the GPS coordinates, and the conformance of monitors and monitor-probes to siting criteria.

2. Date Established

The date that each existing monitoring station was established is shown in the description. For proposed air monitoring stations, the date that the station is expected to be in operation is included in the annual Summary of Network Changes.

3. Site Approval Status

Each monitoring station in the existing network has been reviewed with the purpose of determining whether it meets all design criteria for inclusion in the SLAMS network. Stations that do not meet the criteria will either be relocated in the immediate area or, when possible, re-sited at the present location. KDAQ may also seek an exemption from certain criteria from the US EPA.

4. Monitoring Objectives

The monitoring network was designed to provide information to be used as a basis for the following actions:

(a) To determine compliance with ambient air quality standards and to plan measures in order to attain these standards.

(b) To activate emergency control procedures in the event of an impending air pollution episode.

(c) To observe pollution trends throughout a region including rural areas and report progress made toward meeting ambient air quality standards.

(d) To provide a database for the evaluation of the effects of air quality on population, land use, and transportation planning; to provide a database for the development and evaluation of air dispersion models.

5. Monitoring Station Designations, Monitor Types, and Network Affiliations

The Annual Network Surveillance document must describe the types of monitors that are used to collect ambient data. Most monitors described in the air quality surveillance network are designated as SLAMS, but some monitors fulfill other requirements. Additionally, monitors may be associated with additional networks beyond the state air program or may be used to fulfill multiple network design requirements.

State and Local Air Monitoring Stations (SLAMS): Requirements for air quality surveillance systems provide for the establishment of a network of monitoring stations designated as SLAMS that measure ambient concentrations of pollutants for which standards have been established. These stations must meet requirements that relate to four major areas: quality assurance, monitoring methodology, sampling interval, and siting of instruments.

Special Purpose (SPM and SPM-Other): Not all monitors and monitoring stations in the air quality surveillance network are included in the SLAMS network. In order to allow the capability of providing monitoring for complaint studies, modeling verification and compliance status, certain monitors are reserved for short-term studies and are designated as either Special Purpose Monitors (SPM) or Other Special Purpose Monitors (SPM-Other).

NCore: NCore is a multi pollutant network that integrates several advanced measurement systems for particulates, pollutant gases and meteorology.

Air Quality Index (AQI): The AQI is a method of reporting that converts pollutant concentrations to a simple number scale of 0-500. Intervals on the AQI scale are related to potential health effects of the daily measured concentrations of major pollutants. AQI reporting is required for all metropolitan statistical areas with a population exceeding 350,000. However, KDAQ provides this service to the general public for multiple areas within the state. KDAQ prepares the index twice daily for release to the public from the pollutant data reported from the selected sites in locations across Kentucky. The ambient air data establishing the AQI is subject to quality assurance procedures and is not considered official.

Emergency Episode Monitoring (Episode): Regulations provide for the operation of at least one continuous SLAMS monitor for each major pollutant in designated locations for emergency episode monitoring. These monitors are placed in areas of worst air quality and provide continual surveillance during episode conditions.

EPA: Monitor operated by the EPA or an EPA contractor. Monitors may be eligible for comparisons against the NAAQS and are typically a part of the CASTNET network.

Non-EPA Federal: Monitors operated by Federal agencies outside of the US EPA (such as the National Park Service) are designated as Non-EPA Federal monitors. These monitors are typically used for special studies, but the data may also be eligible for comparisons against the NAAQS.

Population Weighted Emissions Index (PWEI): On June 22, 2010, the US EPA released a new SO_2 Final Rule and a set of monitoring requirements. The requirements use a Population Weighted Emissions Index (PWEI) that is calculated for each Core-Based Statistical Area (CBSA). The PWEI is calculated by multiplying the population of each CBSA and the total amount of SO_2, in tons per year, that is emitted within the CBSA based upon county level data from the National Emissions Inventory (NEI). The result is then divided by one million to provide the PWEI value, which is expressed in a unit of million persons-tons per year. PWEI requirements technically apply to the MSA and are not monitor specific. Any SO_2 used to fulfill MSA PWEI requirements must first and foremost be designated as SLAMS.

Regional Administrator 40 (RA-40): On February 9, 2010, the US EPA released a new NO_2 Final Rule and a new set of monitoring requirements. Under the new monitoring regulations, the EPA Regional Administrator must collaborate with agencies to establish or designate 40 NO_2 monitoring locations, with a primary focus on protecting susceptible and vulnerable populations. RA-40 NO_2 monitors are SLAMS monitors foremost.

Maximum Ozone Concentration: Each Metropolitan Statistical Area (MSA) must have at least one ozone monitor designated to record maximum expected ozone concentrations. These monitors are first and foremost SLAMS (or SLAMS-like) monitors.

6. Monitoring Methods

All sampling and analytical procedures used for NAAQS compliance in the air-monitoring network conform to Federal reference (FRM), alternate (FAM), or equivalent (FEM) methods. In case there is no federal method, procedures are described in the Kentucky Air Quality Monitoring and Quality Assurance Manuals.

(a) Particulate Matter 10 Microns in Size (PM_{10})

All PM_{10} samplers operated by KDAQ are certified as either FRM or FEM samplers and are operated according to the requirements set forth in 40 CFR 50 and 40 CFR 53. Intermittent samplers typically collect a 24-hour sample every sixth day on 46.2 mm PTFE filters. However, certain sites may collect samples more frequently to address local air quality concerns. Filters are sent to a contract laboratory, where they are weighed before and after a sample run. The gain in weight in relation to the volume of air sampled is calculated in micrograms per cubic meter (ug/m^3). The PTFE filters are to be equilibrated before each weighing for a minimum of 24 hours at a 20-23 degrees C mean temperature and a 30-40% mean relative humidity.

LMAPCD currently operates PM_{10} BAMs, which measure PM_{10} through beta ray attenuation. After passing through an inlet designed to limit the size of particulate matter to 10 microns or less, the sample stream passes through filter tape, which is then placed in between a beta source and a scintillation detector causing an attenuation of the beta particle signal. The data is transmitted by telemetry for entry into an automated central data acquisition system. LMAPCD plans to discontinue use of PM_{10} BAMs and install Teledyne-API T640x that will measure PM 2.5, 10 and PM coarse 10-2.5. PM coarse is particulate matter with an aerodynamic diameter in the nominal range of 2.5 to 10 micrometers.

TAPI T640x monitors collect $PM_{2.5,}$ PM10, and $PM_{10\text{-}2.5}$ data continuously via the principle of broadband particle-scattering spectroscopy. During sampling, ambient air is pulled into an inlet at a rate of 16.7 lpm and through a sample conditioner, prior to being introduced to a particle sensor equipped with a polychromatic (broadband) LED. Particles in the sample reflect light from the LED, which is measured by the analyzer and used to calculate the particle -mass of the sample.

(b) Particulate Matter 2.5 Microns in Size ($PM_{2.5}$)

The Division currently operates continuous TEOM monitors and manual intermittent samplers for monitoring particulate matter 2.5 microns in size ($PM_{2.5}$). The Division plans to install several more Teledyne-API (TAPI) T640 continuous $PM_{2.5}$ spectroscopy monitors in the upcoming year. With the exception of continuous TEOM monitors, all $PM_{2.5}$ samplers and monitors operated by KDAQ are certified as either reference or equivalent methods. All FRM manual intermittent samplers are operated per the requirements set forth in 40 CFR 50, Appendix L. Samples are collected on 46.2 mm PTFE filters over a 24-hour sampling period, with airflow maintained at 16.7 liters per minute. Filters are sent to a contract laboratory, where they are weighed before and after a sample run. The gain in weight in relation to the volume of air sampled is calculated in micrograms per cubic meter (ug/m^3). Samples must be retrieved within 177 hours of the end of the sample run and are kept cool (4 degrees C or cooler) during transit to the contract laboratory. The PTFE filters are to be equilibrated before each weighing for a minimum of 24 hours at a controlled atmosphere of 20-23 degrees C mean temperature and 30-40% mean relative humidity. Filters must be used within thirty days of initial weighing. Filters must be re-weighed within thirty days of the end of the sample run and must be kept at 4 degrees C or cooler.

Continuous $PM_{2.5}$ TEOM monitors provide 24-hour samples daily for AQI reporting. During sampling, ambient air passes through an inlet and very sharp cut cyclone designed to pass only particles smaller than 2.5 microns in diameter. After exiting the inlet, the sample stream is sent to a mass transducer. Inside the transducer the sample stream passes through a Teflon-coated glass fiber filter. This filter is weighed every two seconds. The difference between the current filter weight and the initial or installed weight gives the total mass of the collected particulate. The mass concentration is computed by dividing the total mass by the flow rate. Data is transmitted by telemetry for entry into the automated central data acquisition system. While usable for the AQI, $PM_{2.5}$ TEOMs are not classified as either FRM or FEM monitors; and thus, are not eligible for comparison to the NAAQS.

TAPI T640 monitors collect $PM_{2.5}$ data continuously via the principle of broadband particle-scattering spectroscopy. During sampling, ambient air is pulled into an inlet at a rate of 5.0 lpm and through a sample conditioner, prior to being introduced to a particle sensor equipped with a polychromatic (broadband) LED. Particles in the sample reflect light from the LED, which is measured by the analyzer and used to calculate the particle-mass of the sample. While the TAPI T640 is designated as a FEM for $PM_{2.5}$, KDAQ is currently only using them for reporting of the AQI.

LMAPCD currently operates continuous $PM_{2.5}$ BAM monitors, which measure $PM_{2.5}$ through beta ray attenuation. During sampling, ambient air passes through an inlet and a cyclone designed to pass only particles smaller than 2.5 microns in diameter. The sample is collected on filter tape as the air passes through the tape. The filter tape is then placed in between a beta source and a scintillation detector causing an attenuation of the beta particle signal. Data is transmitted by telemetry for entry into the automated central data acquisition system. LMAPCD plans to install several Teledyne-API (TAPI) T640 continuous $PM_{2.5}$ spectroscopy monitors in the upcoming year.

Continuous $PM_{2.5}$ BAMs provide 24-hour daily reporting for the AQI. The data obtained from $PM_{2.5}$ BAMs may or may not be used for comparison to the NAAQS. $PM_{2.5}$ BAMS that are operated as FEMs, and demonstrate comparability to the data obtained from manual FRM samplers, are eligible for comparisons to the NAAQS. A statement on the use of continuous FEM $PM_{2.5}$ monitors is included in the appendices of this document.

(c) **$PM_{2.5}$ Speciation and Carbon Speciation Sampling and Analysis**

In addition to operating $PM_{2.5}$ samplers that determine only $PM_{2.5}$ mass values, LMAPCD also operates $PM_{2.5}$ speciation samplers that collect samples that are analyzed to determine the chemical makeup of $PM_{2.5}$. Samples are collected on a set of two filters, one comprised of Teflon and one comprised of nylon, over a 24-hour sampling period. The filters are composed of either Teflon or nylon in order to collect specific types of toxic pollutants. A second instrument collects a sample on a quartz filter over a 24-hour sampling period. The quartz filter is used to collect a speciated carbon sample.

After collection, the samples are shipped in ice chests to an EPA contract laboratory for analysis. At the laboratory, the samples are analyzed using optical and electron microscopy, thermal-optical analysis, ion chromatography, and x-ray fluorescence to determine the presence and level of specific toxic compounds. Sample results are entered in the AQS data system.

(d) **Sulfur Dioxide (SO_2)**

Instruments used to continuously monitor sulfur dioxide levels in the atmosphere employ the UV fluorescence method. The continuous data output from the instrument is transmitted by telemetry for entry into an automated central data system.

Calibration of these instruments is done dynamically using certified gas mixtures containing a known concentration of sulfur dioxide gas. This gas is then diluted in a specially designed apparatus to give varying known concentrations of sulfur dioxide. These known concentrations are supplied to the instruments, which are adjusted so that instrument output corresponds with the specific concentrations. Calibration curves are prepared for each instrument and each data point is automatically compared to this curve before entry into the data acquisition system.

(e) **Carbon Monoxide (CO)**

Continuous monitoring for carbon monoxide is performed by use of the non-dispersive infrared correlation method. Data is transmitted by telemetry for entry in an automated central data acquisition system.

Calibration of the instrument is performed periodically by using nitrogen or zero air to establish the zero baseline and NIST or NIST traceable gas mixtures of carbon monoxide in air. The span is checked daily using a certified mixture of compressed gas containing approximately 45 parts per million carbon monoxide.

(f) **Ozone (O_3)**

Ozone is monitored using the UV photometry methods. The continuous data output from the instrument is transmitted by telemetry for entry into an automated central data acquisition system.

Monitors are calibrated routinely using an ozone generator, which is calibrated using the ultra violet photometry reference method. Calibration curves are prepared for each instrument and each data point is automatically compared to this curve before entry into the data acquisition system.

(g) **Nitrogen Dioxide (NO_2)**

KDAQ uses the chemiluminescence method for monitoring the nitrogen dioxide level in the ambient air. The continuous data output from the instrument is transmitted by telemetry for entry into an automated central data acquisition system.

LMAPCD utilizes the Cavity-Attenuated Phase-Shift (CAPS) spectroscopy method as well as chemiluminescence to measure nitrogen dioxide and total reactive nitrogen (NO/NOy) respectively.

Calibration of these instruments is done dynamically using NIST certified gas mixtures of nitric oxide. Through the use of dilution apparatus, varying concentrations are produced and supplied to the monitors, thus producing a specific calibration curve for each instrument. Each data point is automatically compared to this curve before entry into the data acquisition system.

(h) **Lead (Pb)**

To determine lead concentrations, KDAQ uses high volume particulate samplers, which collect samples of suspended particulates onto 8 x 10 glass fiber filters. The samplers use a brushless motor and a critical flow orifice in order to achieve a sampling flow rate between 1.10 and 1.70 cubic meters per minute (m^3/min) over the course of 24 hours. Upon collection, the filters are sent to an US EPA certified laboratory for analysis. The sample filters are cut into strips, acid digested according to 40 CFR Part 50, Appendix G, and analyzed by Inductively Coupled Plasma with Mass Spectroscopy Detection (ICP-MS).

(i) **Air Toxics**

Air toxics samples are classified into four categories: metals, volatile organic compounds (VOC), polycyclic aromatic hydrocarbons (PAH), and carbonyls.

Metal samples are collected on 46.2 mm PTFE filters over a 24-hour period from the PM_{10} monitoring method. The filter is weighed before and after the sample run by a contract laboratory. The gain in weight in relation to the volume of air sampled is used to calculate the concentration in micrograms per cubic meter (ug/m^3). The filter is then delivered to a separate US EPA contract laboratory for analysis by inductively coupled plasma/mass spectrometer analysis.

VOC samples are collected in a passivated vacuum canister. Ambient air is pulled into the canister over a 24-hour sampling period. The sample is shipped to an US EPA contract laboratory for analysis via gas chromatography. Additionally, LMAPCD plans to operate continuous automatic gas chromatographs, which continuously monitor for various hazardous air pollutants.

PAH samples are collected by a hi-volume air sampler over a 24-hour period. The sample is collected on a polyurethane foam filter cartridge. After sampling, the filter cartridge is packed on ice and shipped to an US EPA contract laboratory for analysis via gas chromatography/mass spectrometry.

Carbonyl samples are collected on a DNPH cartridge. An ambient air stream flows through the cartridge at a one-liter per minute flow rate for a 24-hour sampling period. The cartridge is packed on ice and shipped to an US EPA contract laboratory for high-pressure liquid chromatography analysis.

(j) **RadNet**

The US EPA RadNet fixed air station consists of a high-volume sampler that pulls ambient air through a 4-inch diameter filter at a rate of 1,000 liters per minute. Filters are collected twice each week. The instrument also consists of two radiation detectors that continuously measure gamma and beta radiation from particulates collected on the air filter. Data is recorded to the monitor's CPU and is sent hourly to the National Air and Radiation Environmental Laboratory (NAREL) for evaluation.

The RadNet network, which has stations in each State, has been used to track environmental releases of radioactivity from nuclear weapons tests and nuclear accidents. RadNet also documents the status and trends of environmental radioactivity. In general, data generated from RadNet provides the information base for making decisions necessary to ensure the protection of public health. The system helps the EPA determine whether additional sampling or other actions are needed in response to particular releases of radioactivity to the environment. RadNet can also provide supplementary information on population exposure, radiation trends, and other aspects of releases. Data is published by NAREL in a quarterly report entitled *Environmental Radiation Data*. While KDAQ and LMAPCD operate the monitors, all other aspects, including maintenance and data responsibility, are handled by the US EPA. For more information, please visit the US EPA's RadNet website: http://www.epa.gov/narel/radnet/.

7. Quality Assurance Status

The Division for Air Quality has an extensive quality assurance program to ensure that all air monitoring data collected is accurate and precise. Staff members audit air monitors on a scheduled basis, including those operated by the Louisville Metro Air Pollution Control District and the National Park Service, to ensure that each instrument is calibrated and operating properly. Agencies audit their data monthly and verify that the data reported by each instrument is recorded accurately in the computerized database.

8. Scale of Representativeness

Each station in the monitoring network must be described in terms of the physical dimensions of the air parcel nearest the monitoring station throughout which actual pollutant concentrations are reasonably similar. Area dimensions or scales of representativeness used in the network description are:

(a) Microscale - defines the concentration in air volumes associated with area dimensions ranging from several meters up to about 100 meters.

(b) Middle scale - defines the concentration typical of areas up to several city blocks in size with dimensions ranging from about 100 meters to 0.5 kilometers.

(c) Neighborhood scale - defines the concentrations within an extended area of a city that has relatively uniform land use with dimensions in the 0.5 to 4.0 kilometers.

(d) Urban scale - defines an overall city-sized condition with dimensions on the order of 4 to 50 kilometers.

(e) Regional Scale - defines air quality levels over areas having dimensions of 50 to hundreds of kilometers.

The scale of representativeness is closely related to the type of air monitoring site and the objectives of that site. There are six basics types of sites supported by the ambient air monitoring network:

(a) To determine the highest concentrations expected to occur in the area covered by the network.

(b) To determine representative concentrations in areas of high population density.

(c) To determine the impact on ambient pollution levels of significant sources or source categories.

(d) To determine the extent of regional transport of pollutants.

(e) To determine general background concentration levels.

(f) To determine impacts on visibility, vegetation damage, or other welfare-based concerns.

The design intent in siting stations is to correctly match the area dimensions represented by the sample of monitored air with the area dimensions most appropriate for the monitoring objective of the station. The following relationship of these six basic site type and the scale of representativeness are appropriate when siting monitoring stations:

Monitoring Site Type	Scale of Representativeness
Highest Concentration	Micro, Middle, Neighborhood
Population Oriented	Neighborhood, Urban
Source Impact	Micro, Middle, Neighborhood
Regional Transport & General Background	Neighborhood, Regional
Welfare-based Impacts	Urban, Regional

Data Processing and Reporting

All ambient air quality data are stored on a server located at the main office building of Commonwealth Office of Technology at 101 Cold Harbor Drive, Frankfort, Kentucky. The server runs a full database back up every night and keeps an hourly transaction log. After each month of data has passed all quality assurance checks, the data is transmitted via telemetry to the US EPA's national data storage system known as AQS. Statistical data summaries are generated from this database and compiled to produce the Ambient Air Quality Annual Report. This report may be accessed at the KDAQ website: http://air.ky.gov. The report is located under Resources.

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AIR MONITORING STATION DESCRIPTIONS

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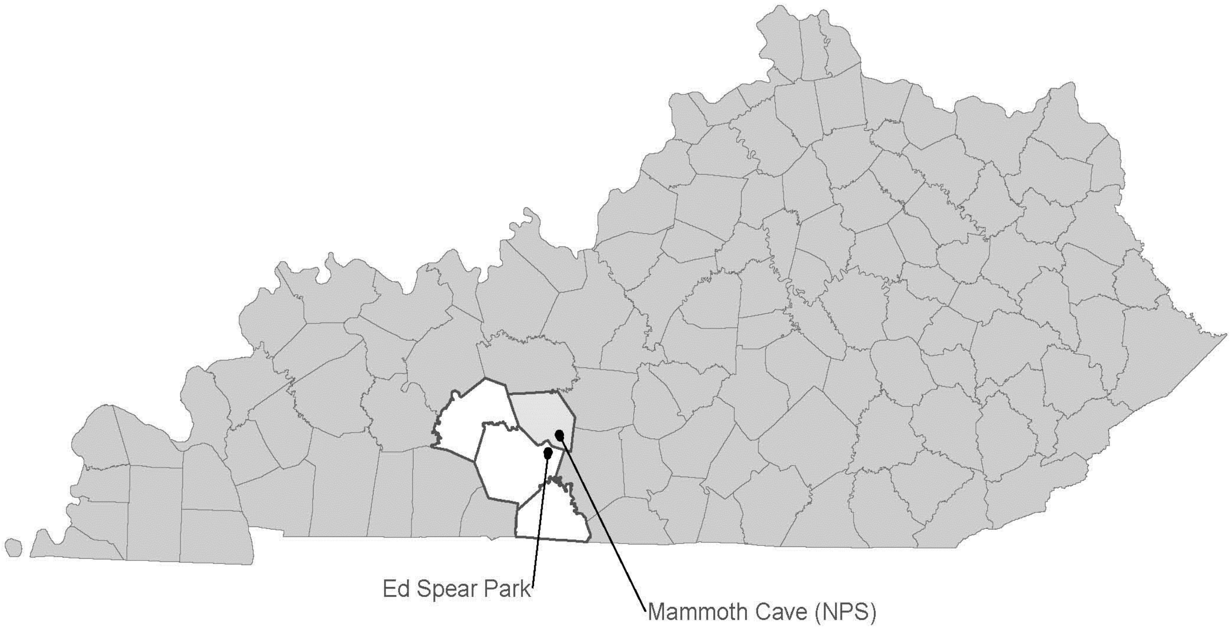
Bowling Green, KY



AQS ID / County	Site Address	PM2.5	Cont. PM2.5	PM10	Cont. PM10	SO2	NO2	NOy	CO	O3	Pb	VOC	Carbonyl	PAH	PM2.5 Spec.	Carbon Spec.	RadNet	Met
21-061-0501 Edmonson	Alfred Cook Road Mammoth Cave (NPS)		1[tF]			1[F]		1[F]	1[F]	1[F, M]								1[F]
21-227-0009 Warren	226 Sunset Street Smiths Grove	2[C]	1[ti]							1[i]								
Totals	**2**	**2**	**2**			**1**		**1**	**1**	**2**								**1**

Tallies are equal to the actual number of monitors present. Superscripts represent additional information about the network.

F =Non-EPA Federal Monitor

C =Collocated

M =Maximum Ozone Concentration Site for MSA

t =Continuous TEOM Monitor

i =AQI Reported

CSA/MSA: Bowling Green-Glasgow, KY CSA; Bowling Green, KY MSA
401 KAR 50:020 Air Quality Region: South Central Kentucky Intrastate (105)
Site Name: Mammoth Cave National Park, Houchin Meadow
AQS Site ID: 21-061-0501
Location: Alfred Cook Road, Park City, KY 42160
County: Edmonson
GPS Coordinates: 37.131944, -86.14778 (NAD83)
Date Established: August 1, 1997
Inspection Date: December 15, 2017
Inspection By: James Plunkett

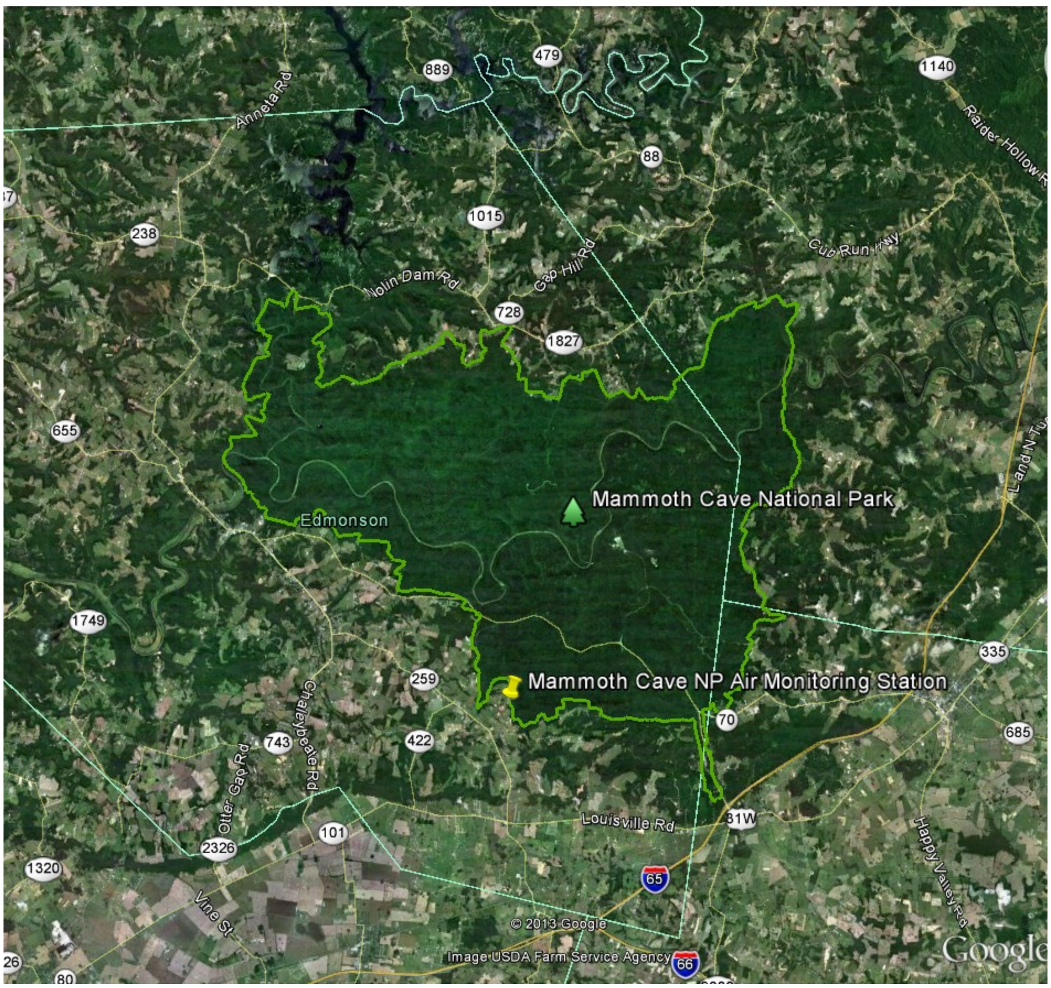
Mammoth Cave National Park was established as one of 156 mandatory Federal Class I Areas nationwide under the Clean Air Act Amendments of 1977. Class I Areas are imparted with the highest level of air quality protections, especially regarding visibility degradation (haze). The Division maintains a cooperative relationship with Mammoth Cave National Park and frequently includes the site's data in air quality analyses. Additionally, the ozone monitor is designated as the "Maximum Ozone Concentration" monitor for the Bowling Green, KY MSA. However, KDAQ does not operate the site nor certify the annual data. While the park conducts a variety of air quality studies, only certain data is reported to the EPA's AQS database.

Monitors:

Monitor Type	Inlet Height (meters)	Designation	Analysis Method	Frequency of Sampling
AEM Ozone	10.4	CASTNET Maximum O_3 Non-EPA Federal	Automated Equivalent Method utilizing UV photometry analysis	Continuously
Sulfur Dioxide	10.2	Non-EPA Federal	Automated Equivalent Method utilizing trace level UV fluorescence analysis	Continuously
Total Reactive Nitrogen (NO/NO_Y)	10.2	Non-EPA Federal	Automated method utilizing trace level chemiluminescence analysis	Continuously
Carbon Monoxide	10.2	Non-EPA Federal	Automated Reference Method utilizing trace level non-dispersive infrared analysis	Continuously

Monitors (Continued):

Monitor Type	Inlet Height (meters)	Designation	Analysis Method	Frequency of Sampling
$PM_{2.5}$ TEOM	4.6	Non-EPA Federal	Tapered element oscillating microbalance, gravimetric.	Continuously
Meteorological	12.1	Non-EPA Federal	AQM grade instruments for wind speed, wind direction, solar radiation, precipitation, humidity, barometric pressure, and temperature	Continuously



CSA/MSA: Bowling Green-Glasgow, KY CSA; Bowling Green, KY MSA
401 KAR 50:020 Air Quality Region: South Central Kentucky Intrastate (105)
Site Name: Ed Spear Park
AQS Site ID: 21-227-0009
Location: 226 Sunset Street, Smiths Grove, KY 42171
County: Warren
GPS Coordinates: 37.04926, -86. 21487 (NAD83)
Date Established: May 3, 2012
Inspection Date: December 15, 2017
Inspection By: James Plunkett
Site Approval Status: Siting and monitor design has been approved by the EPA.

This monitoring site was established as a replacement for the Oakland (Warren County) air monitoring station (21-227-0008). In October 2010, the Oakland site was found to be sitting within the doline of a sinkhole and was discontinued. Monitoring was established at the new Ed Spear Park site in May 2012. Inspections found the sample lines and equipment to be in good condition. The sample inlets are 35.2 meters from the nearest road. The site meets the requirements of 40 CFR 58, Appendices A, C, D, E and G.

Monitoring Objective:
The monitoring objectives are to determine compliance with National Ambient Air Quality Standards. While not required for the CBSA, the site also provides levels of ozone and particulate matter for daily index reporting.

Monitors:

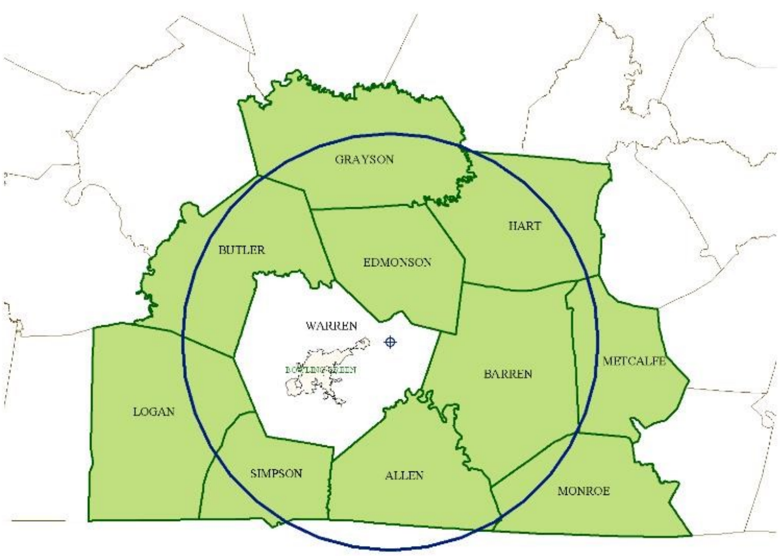
Monitor Type	Inlet Height (meters)	Designation	Analysis Method	Frequency of Sampling
AEM Ozone	4.5	SLAMS AQI	UV photometry	Continuously March 1 – October 31
$PM_{2.5}$ TEOM	4.6	SPM AQI	Tapered element oscillating microbalance, gravimetric	Continuously
FRM $PM_{2.5}$	2.3	SLAMS	Gravimetric	24-hours every third day
Collocated FRM $PM_{2.5}$	2.3	SLAMS	Gravimetric	24-hours every sixth day

Quality Assurance Status:
All Quality Assurance procedures have been implemented in accordance with 40 CFR 58, Appendix A.

Area Representativeness:
This site represents population exposure on a neighborhood scale for particulates. This site also represents population exposure on an urban scale for ozone.

Neighborhood Scale: Particulates

Urban Scale: Ozone



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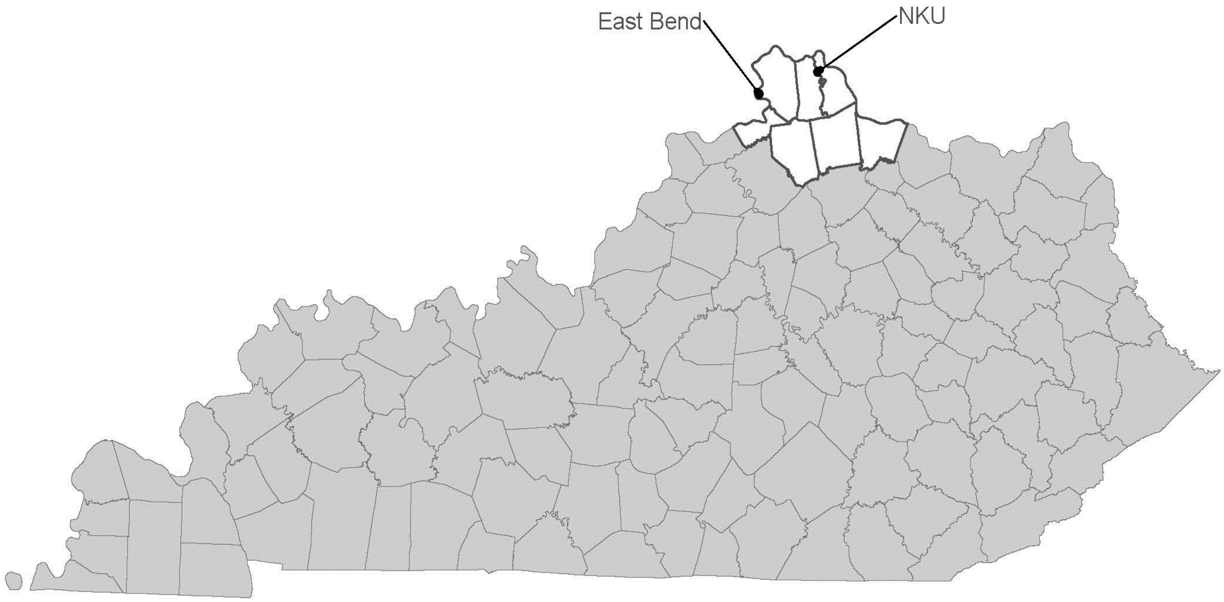
Cincinnati, OH-KY-IN



AQS ID / County	Site Address	PM2.5	Cont. PM2.5	PM10	Cont. PM10	SO2	NO2	NOy	CO	O3	Pb	VOC	Carbonyl	PAH	PM2.5 Spec.	Carbon Spec.	RadNet	Met
21-015-0003 Boone	KY338 & Lower River Union									1								1
21-037-3002 Campbell	524A John's Hill Rd Highland Heights	2^{C}	1^{Si}			1^{iP}	1^{i}			1^{ei}								
Totals	**2**	**2**	**1**			**1**	**1**			**2**								**1**

Tallies are equal to the actual number of monitors present. Superscripts represent additional information about the network.

i = AQI Reported
P = PWEI Monitor
C = Collocated Monitors
e = Emergency Episode Monitor
S = Continuous PM T640 Monitor

Rev. 5/1/16

CSA/MSA: Cincinnati-Wilmington-Maysville, OH-KY-IN CSA; Cincinnati, OH-KY-IN MSA
401 KAR 50:020 Air Quality Region: Metropolitan Cincinnati (Ohio) Interstate (079)
Site Name: East Bend
AQS Site ID: 21-015-0003
Location: KY 338 and Lower River Road, Union, KY 41091
County: Boone
GPS Coordinates: 38.918330, -84.852637 (NAD 83)
Date Established: July 1, 1977
Inspection Date: November 28, 2017
Inspection By: Shauna Switzer
Site Approval Status: Site and monitors meet all design criteria for the monitoring network.

The monitoring site is a stationary equipment shelter located at the intersection of KY 338 and Lower River Road near East Bend, Kentucky. The sample inlet is 15 meters from the nearest road. Upon inspection, the sample line and monitor were found to be in good condition. The site meets the requirements of 40 CFR 58, Appendices A,C, D and E.

Monitoring Objective:
The monitoring objective is to determine compliance with National Ambient Air Quality Standards.

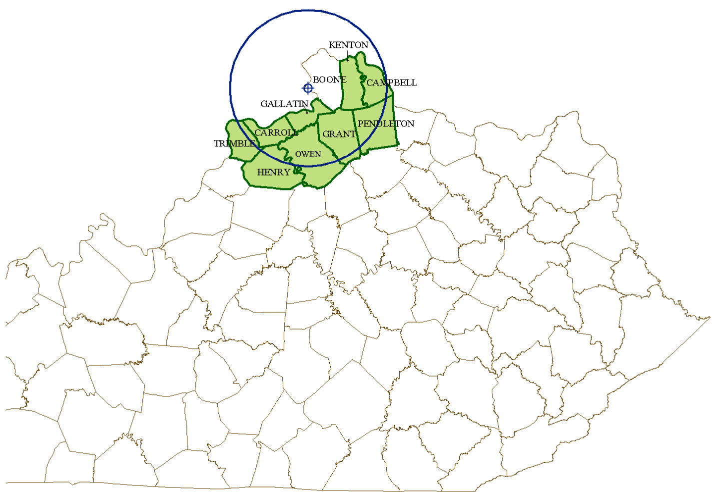
Monitors:

Monitor Type	Inlet Height (meters)	Designation	Analysis Method	Frequency of Sampling
AEM Ozone	3.6	SLAMS	UV photometry	Continuously March 1 – October 31
Meteorological	5.9	Other	AQM grade instruments for wind speed, wind direction, humidity, barometric pressure and temperature	Continuously

Quality Assurance Status:
All Quality Assurance procedures have been implemented in accordance with 40 CFR 58, Appendix A.

Area Representativeness:
This site represents the upwind background levels on an urban scale for ozone.

Urban Scale



CSA/MSA: Cincinnati-Wilmington-Maysville, OH-KY-IN CSA; Cincinnati, OH-KY-IN MSA
401 KAR 50:020 Air Quality Region: Metropolitan Cincinnati (Ohio) Interstate (079)
Site Name: Northern Kentucky University (NKU)
AQS Site ID: 21-037-3002
Location: 524A John's Hill Road, Highland Heights, KY 41076
County: Campbell
GPS Coordinates: 39.02181, -84.47445 (NAD 83)
Date Established: August 1, 2007
Inspection Date: November 28, 2017
Inspection By: Shauna Switzer
Site Approval Status: Site and monitors meet all design criteria for the monitoring network.

The monitoring site is a stationary equipment shelter located on farmland owned by Northern Kentucky University in Highland Heights, Kentucky. The sample inlets are 448 meters from the nearest road, which is Interstate 275. Upon inspection, the sample lines and monitors were found to be in good condition. The site meets the requirements of 40 CFR 58, Appendices A, C, D, E and G.

Monitoring Objective:
The monitoring objectives are to determine compliance with National Ambient Air Quality Standards; to provide ozone, particulate, nitrogen dioxide, and sulfur dioxide levels for daily index reporting; and to detect elevated pollutant levels for activation of emergency control procedures for ozone.

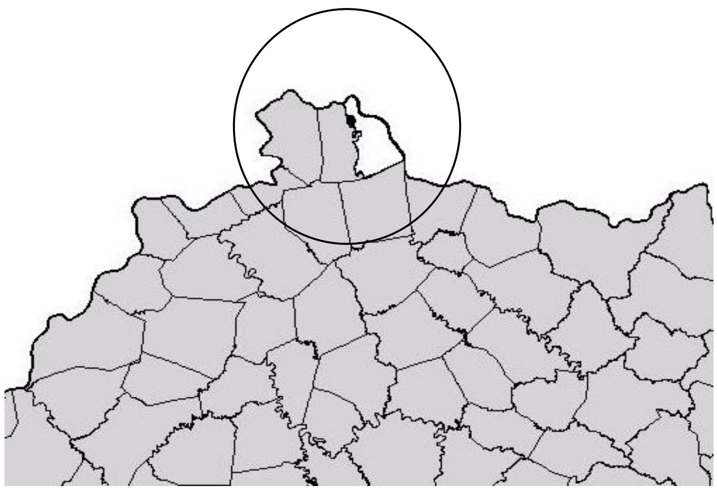
Monitors:

Monitor Type	Inlet Height (meters)	Designation	Analysis Method	Frequency of Sampling
AEM Nitrogen Dioxide (NO_2, NO, NO_x)	3.8	SLAMS AQI	Chemiluminescence	Continuously
AEM Ozone	3.8	SLAMS AQI EPISODE	UV photometry	Continuously March 1 – October 31
FRM $PM_{2.5}$	4.5	SLAMS	Gravimetric	24-hours every third day
Collocated FRM $PM_{2.5}$	TBD	SLAMS	Gravimetric	24-hours every sixth day
$PM_{2.5}$ Continuous	TBD (Install date 2/12/18)	SPM AQI	Broadband Spectroscopy	Continuously
AEM Sulfur Dioxide	3.8	SLAMS AQI PWEI	UV fluorescence	Continuously

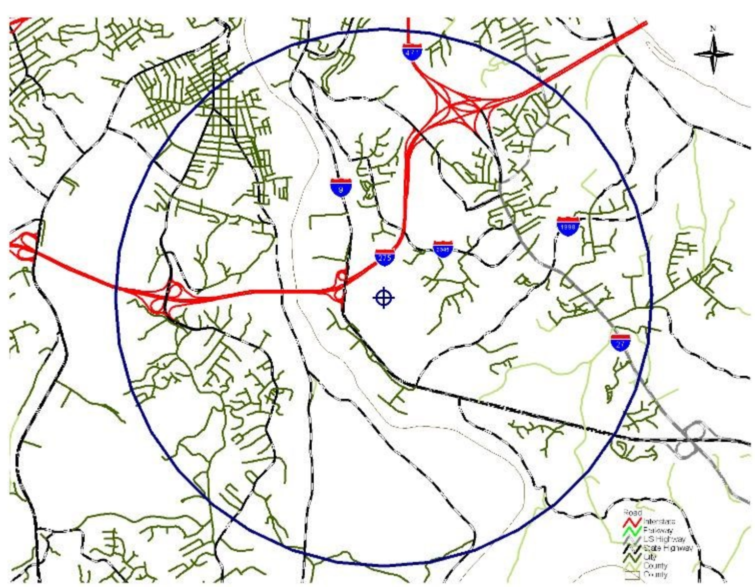
Quality Assurance Status:
All Quality Assurance procedures have been implemented in accordance with 40 CFR 58, Appendix A.

Area Representativeness:
This site represents population exposure for nitrogen dioxide, ozone, and sulfur dioxide on an urban scale. This site also represents population exposure on a neighborhood scale for particulate matter.

Urban Scale: Nitrogen Dioxide, Ozone, Sulfur Dioxide



Neighborhood Scale: Particulates



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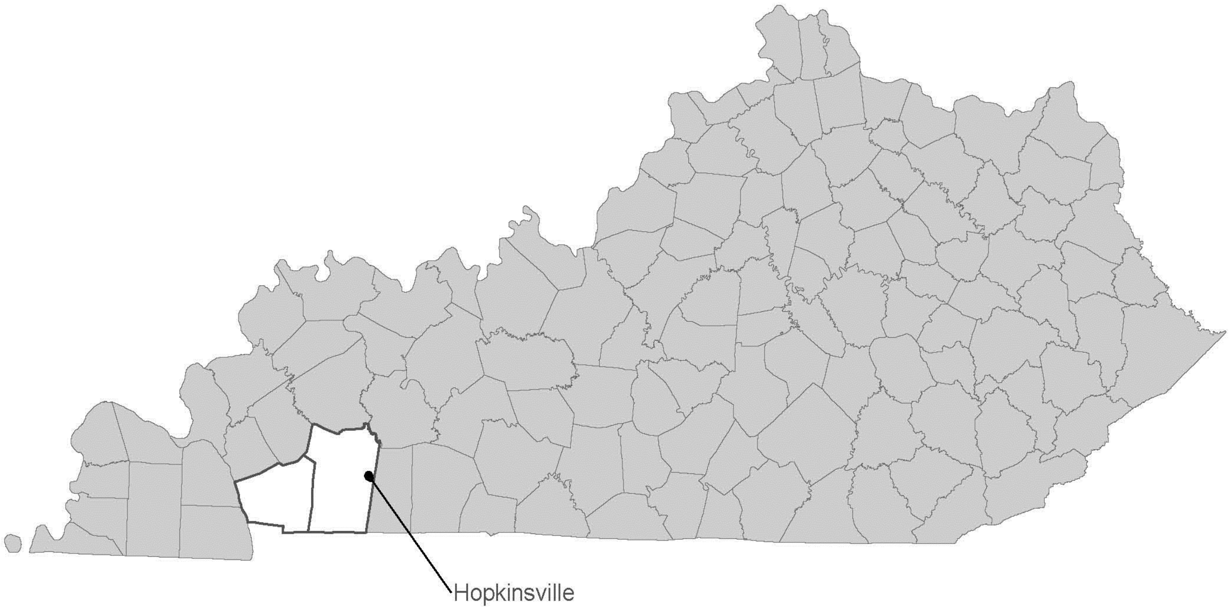
Clarksville, TN-KY



AQS ID / County	Site Address	PM2.5	Cont. PM2.5	PM10	Cont. PM10	SO2	NO2	NOy	CO	O3	Pb	VOC	Carbonyl	PAH	PM2.5 Spec.	Carbon Spec.	RadNet	Met
21-047-0006 Christian	10800 Pilot Rock Rd Hopkinsville	1[X]								1								1
Totals	**1**	**1**								**1**								**1**

Tallies are equal to the actual number of monitors present. Superscripts represent additional information about the network.

X =Regional Transport PM2.5 Monitor

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CSA/MSA: Clarksville, TN- KY MSA
401 KAR 50:020 Air Quality Region: Paducah - Cairo Interstate (072)
Site Name: Hopkinsville
AQS Site ID: 21-047-0006
Location: 10800 Pilot Rock Road, Hopkinsville, KY 42240
County: Christian
GPS Coordinates: 36.91171, -87.32337 (NAD 83)
Date Established: January 1, 1999
Inspection Date: December 19, 2017
Inspection By: Shauna Switzer
Site Approval Status: Site and monitors meet all design criteria for the monitoring network.

The monitoring site consists of a $PM_{2.5}$ monitoring platform and an adjacent stationary equipment shelter. The site is located in a field on the property of a private residence, located at 10800 Pilot Rock Road in Hopkinsville, Kentucky. The sample inlets are 116 meters from the nearest road. Upon inspection, the sample inlets and monitors were found to be in good condition. The site meets the requirements of 40 CFR 58, Appendices A, C, D and E.

Monitoring Objective:

The monitoring objectives are to determine compliance with National Ambient Air Quality Standards and to determine levels of interstate regional transport of fine particulate matter and ozone.

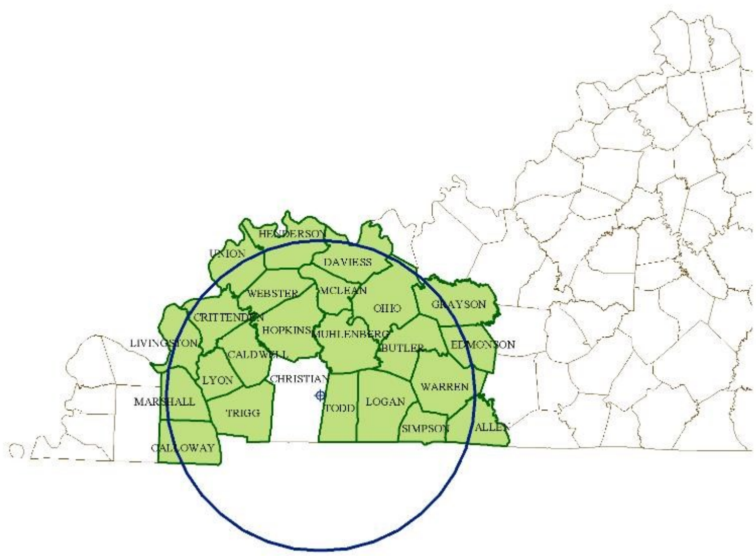
Monitors:

Monitor Type	Inlet Height (meters)	Designation	Analysis Method	Frequency of Sampling
AEM Ozone	3.7	SLAMS	UV photometry	Continuously March 1 – October 31
FRM $PM_{2.5}$	2.2	SLAMS	Gravimetric	24-hours every third day
Meteorological	5.5	Other	AQM grade instruments for wind speed, wind direction, relative humidity, barometric pressure, and temperature	Continuously

Quality Assurance Status:
All Quality Assurance procedures have been implemented in accordance with 40 CFR 58, Appendix A.

Area Representativeness:
This site represents population exposure on a regional scale for ozone and $PM_{2.5}$.

Regional Scale: Ozone, Particulates



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Elizabethtown-Fort Knox, KY

AQS ID / County	Site Address	PM2.5	Cont. PM2.5	PM10	Cont. PM10	SO2	NO2	NOy	CO	O3	Pb	VOC	Carbonyl	PAH	PM2.5 Spec.	Carbon Spec.	RadNet	Met
21-093-0006 Hardin	801 North Miles St. Elizabethtown	2[C]	1[t]							1[M]								
Totals	**1**	**2**	**1**							**1**								

Tallies are equal to the actual number of monitors present. Superscripts represent additional information about the network.

C =Collocated

t =Continuous TEOM Monitor

M =Maximum Ozone Concentration Site for MSA

Rev. 5/1/16

CSA/MSA: Louisville/Jefferson County-Elizabethtown-Madison, KY-IN CSA; Elizabethtown-Fort Knox, KY MSA
401 KAR 50:020 Air Quality Region: North Central Kentucky Intrastate (104)
Site Name: Elizabethtown
AQS Site ID: 21-093-0006
Location: American Legion Park, 801 North Miles Street, Elizabethtown, KY 42701
County: Hardin
GPS Coordinates: 37.705635, -85.852656 (NAD 83)
Date Established: February 24, 2000
Inspection Date: November 22, 2017
Inspection By: Shauna Switzer
Site Approval Status: Site and monitors meet all design criteria for the monitoring network.

The monitoring site is a stationary equipment shelter located near the tennis courts on the grounds of the American Legion Park in Elizabethtown, Kentucky. In 2012, the site was moved approximately 23 meters due to potential expansion of a nearby park building. From the new location, the sample inlets are approximately 44 meters from the nearest road. Upon inspection, the sample lines and monitors were found to be in good condition. The site meets the requirements of 40 CFR 58, Appendices A, C, D, and E.

Monitoring Objective:
The monitoring objectives are to determine compliance with National Ambient Air Quality Standards.

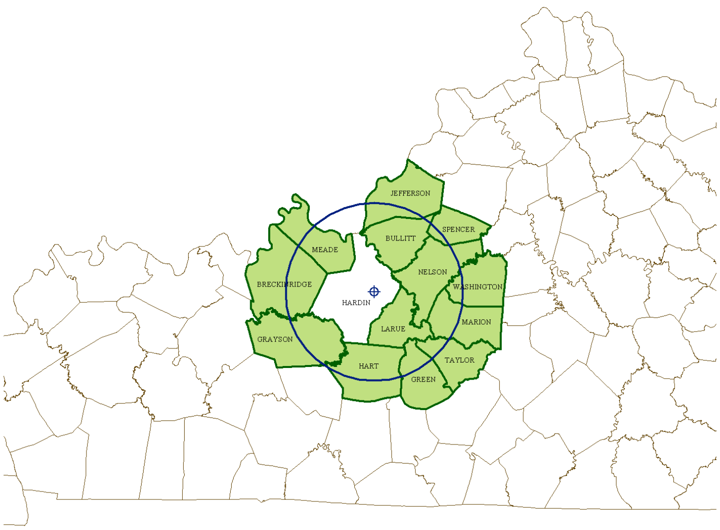
Monitors:

Monitor Type	Inlet Height (meters)	Designation	Analysis Method	Frequency of Sampling
AEM Ozone	3.6	SLAMS Maximum O_3	UV photometry	Continuously March 1 – October 31
FRM $PM_{2.5}$	4.6	SLAMS	Gravimetric	24-hours every third day
Collocated FRM $PM_{2.5}$	4.6	SLAMS	Gravimetric	24-hours every sixth day
$PM_{2.5}$ TEOM	4.6	SPM	Tapered elemental oscillating microbalance, gravimetric	Continuously

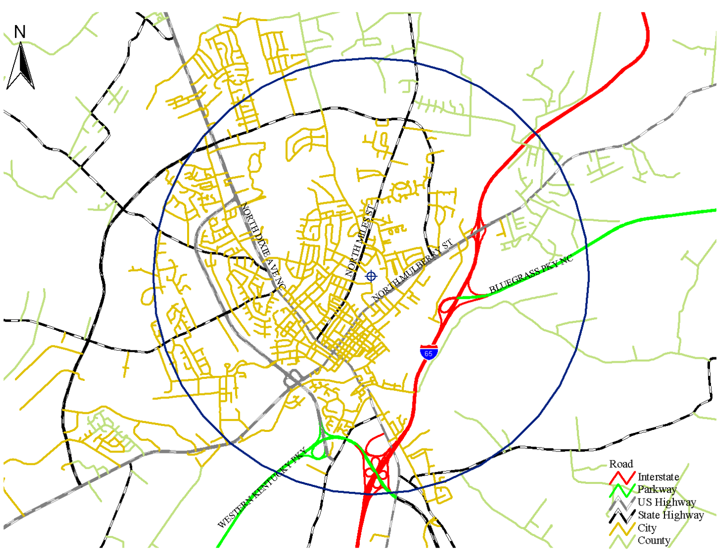
Quality Assurance Status:
All Quality Assurance procedures have been implemented in accordance with 40 CFR 58, Appendix A.

Area Representativeness:
This site represents population exposure on a neighborhood scale for particulates and population exposure on an urban scale for ozone.

Urban Scale: Ozone



Neighborhood Scale: Particulates



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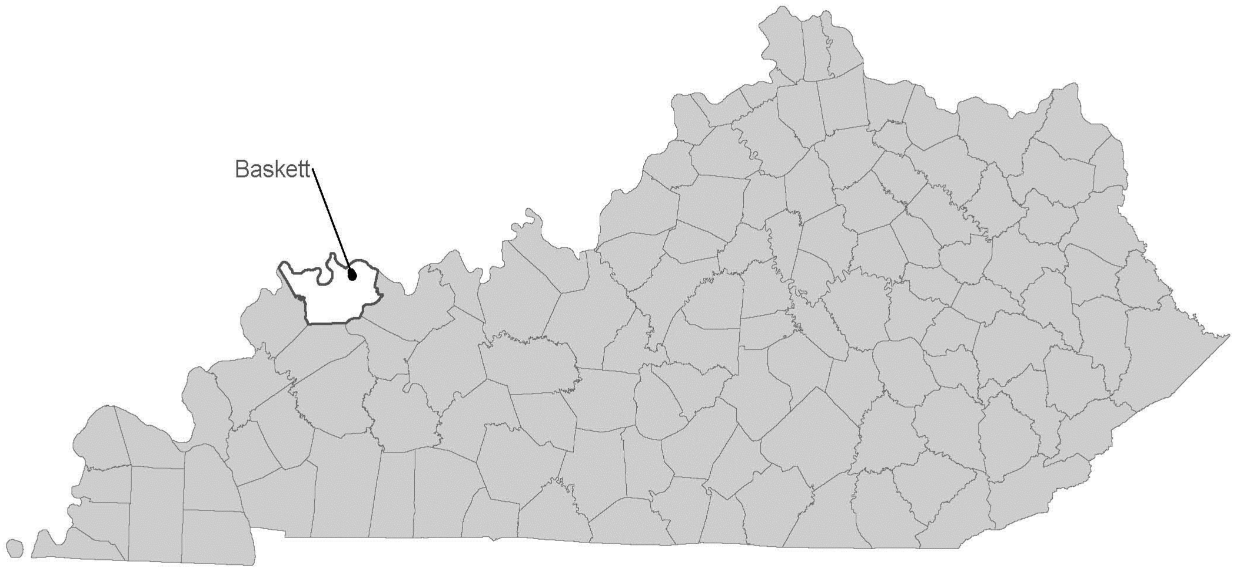
Evansville, IN-KY



AQS ID / County	Site Address	PM2.5	Cont. PM2.5	PM10	Cont. PM10	SO2	NO2	NOy	CO	O3	Pb	VOC	Carbonyl	PAH	PM2.5 Spec.	Carbon Spec.	RadNet	Met
21-101-0014 Henderson	7492 Dr. Hodge Rd. Baskett	1	1[S]	1[m]		1[P]				1[M]								
21-101-1011	Alcan Aluminum Rd. Robards, KY 42452					1[DRR]												
Totals	**2**	**1**	**1**	**1**		**2**				**1**								

Tallies are equal to the actual number of monitors present. Superscripts represent additional information about the network.

S = Continuous PM T640 Monitor
m = PM10 Filter Analyzed for Metals
M = Maximum Ozone Concentration Site for MSA
DRR = SO2 Data Requirements Rule Monitor
P = PWEI Monitor

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CSA/MSA: Evansville, IN-KY MSA
401 KAR 50:020 Air Quality Region: Evansville-Owensboro-Henderson Interstate (077)
Site Name: Baskett
AQS Site ID: 21-101-0014
Location: Baskett Fire Department, 7492 Dr. Hodge Road, Henderson, KY 42420
County: Henderson
GPS Coordinates: 37.87120, -87.46375 (NAD 83)
Date Established: February 27, 1992
Inspection Date: December 20, 2017
Inspection By: Shauna Switzer
Site Approval Status: Site and monitors meet design criteria for the monitoring network.

The monitoring site is a stationary equipment shelter located on the grounds of the Baskett Fire Department in Baskett, Kentucky. Upon inspection, the sample lines and monitors were found to be in good condition. The sample inlets are 5.7 meters from the nearest road, which is closer than the allowable-distances stated by CFR. Due to the small traffic count of the street and the unlikely influence of vehicles on data, KDAQ has received EPA-approval for a waiver from the required road-distances stated by 40 CFR 58, Appendix E. Otherwise, the site meets the requirements of 40 CFR 58, Appendices A, C, D, and E.

Monitoring Objective:
The monitoring objectives are to determine compliance with National Ambient Air Quality Standards.

Monitors:

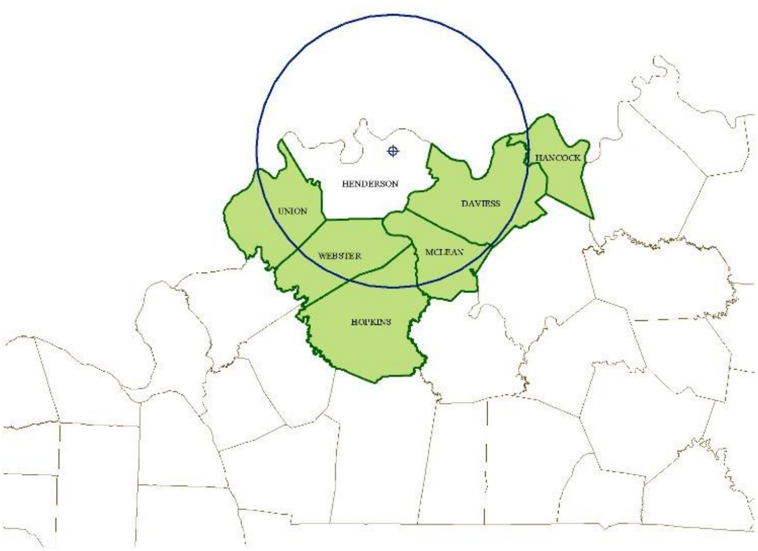
Monitor Type	Inlet Height (meters)	Designation	Analysis Method	Frequency of Sampling
AEM Ozone	3.9	SLAMS Maximum O_3	UV photometry	Continuously March 1 – October 31
FRM $PM_{2.5}$	4.7	SLAMS	Gravimetric	24-hours every third day
$PM_{2.5}$ Continuous	TBD (Install date 2/19/18)	SPM AQI	Broadband Spectroscopy	Continuously
FRM PM_{10}	4.5	SLAMS	Gravimetric	24-hours every sixth day
- PM_{10} Metals		SPM-Other	Determined from the PM_{10} sample using EPA method IO 3.5	Same as PM_{10}
AEM Sulfur Dioxide	3.8	SLAMS PWEI	UV fluorescence	Continuously

Quality Assurance Status:
All Quality Assurance procedures have been implemented in accordance with 40 CFR 58, Appendix A.

Area Representativeness:
This site represents maximum concentrations on an urban scale for ozone. This site also represents population exposure on a neighborhood scale for particulates and sulfur dioxide.

Neighborhood Scale: Particulates, Sulfur Dioxide

Urban Scale: Ozone



CSA/MSA: Evansville, IN-KY MSA
401 KAR 50:020 Air Quality Region: Evansville-Owensboro-Henderson Interstate (077)
Site Name: Sebree SO_2 DRR Site
AQS Site ID: 21-101-1011
Location: Alcan Aluminum Road
County: Henderson
GPS Coordinates:
Date Established: January 1, 2017
Inspection Date: December 20, 2017
Inspection By: Shauna Switzer
Site Approval Status: Site and monitor meet design criteria for the monitoring network.

On August 10, 2015, the EPA finalized requirements in 40 CFR 51, Subpart BB requiring air pollution control agencies to monitor ambient sulfur dioxide (SO_2) concentrations in areas with large sources of sulfur dioxide emissions in order to assist in the implementation for the one-hour SO_2 National Ambient Air Quality Standard (NAAQS). Known as the "Data Requirements Rule (DRR)," this action established that, at a minimum, agencies must characterize air quality around sources that emit 2,000 tons per year (tpy) or more of sulfur dioxide. The site meets the requirements of 40 CFR 58, Appendices A, C, D, and E.

As allowed by the DRR, an ambient air monitoring site has been established near Sebree, Kentucky, to characterize maximum hourly sulfur dioxide concentrations in the immediate vicinity of the Big Rivers Electric Corporation and Century Aluminum Sebree, LLC facilities. The site is located at the intersection of Alcan Aluminum Road and a facility coal-truck access road, approximately 1/2 mile south of State Route 2678.

Monitoring Objective:
The monitoring objectives are to determine compliance with National Ambient Air Quality Standards.

Monitors:

Monitor Type	Inlet Height (meters)	Designation	Analysis Method	Frequency of Sampling
AEM Sulfur Dioxide	3.8	SLAMS	UV fluorescence	Continuously

Quality Assurance Status:
All Quality Assurance procedures have been implemented in accordance with 40 CFR 58, Appendix A.

Area Representativeness:
This site also represents population exposure on a neighborhood scale for sulfur dioxide.

Neighborhood Scale: Sulfur Dioxide

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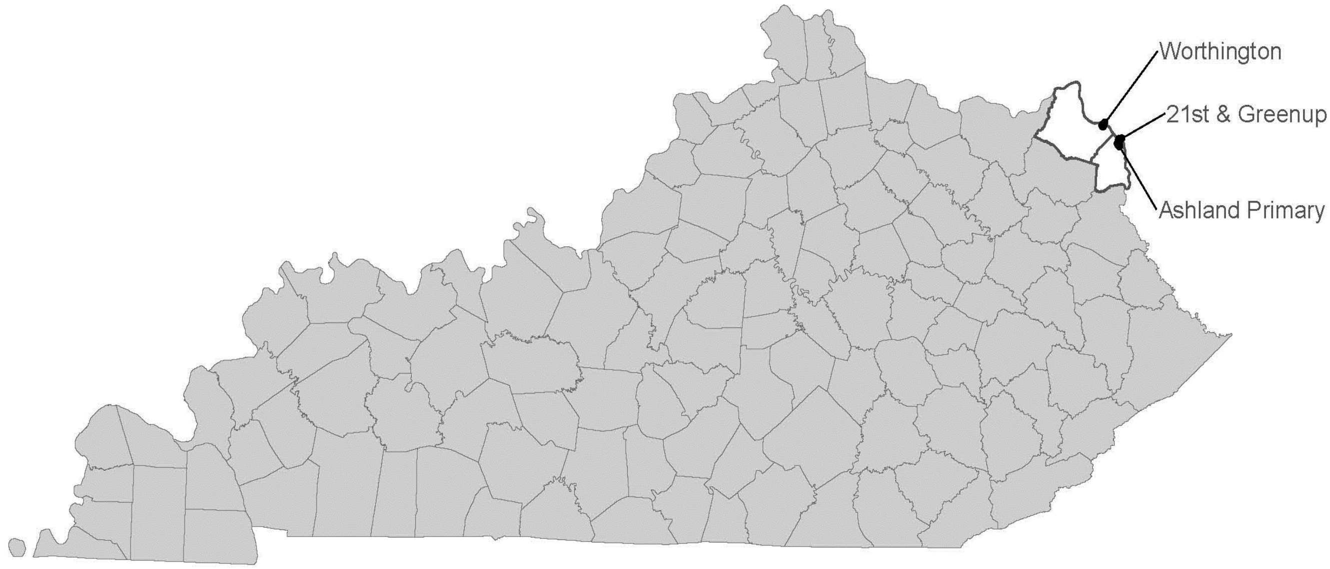
Huntington-Ashland, WV-KY-OH



AQS ID / County	Site Address	PM2.5	Cont. PM2.5	PM10	Cont. PM10	SO2	NO2	NOy	CO	O3	Pb	VOC	Carbonyl	PAH	PM2.5 Spec.	Carbon Spec.	RadNet	Met
21-019-0002 Boyd	122 22nd Street Ashland			2^{Cm}														
21-019-0017 Boyd	2924 Holt Street Ashland	1	1^{Si}			1^{eiP}	1^{ei}			1^{eiM}								1
21-089-0007 Greenup	Scott St. & Center Ave. Worthington					1^{e}				1^{e}								
Totals	**3**	**1**	**1**	**2**		**2**	**1**			**2**								**1**

Tallies are equal to the actual number of monitors present. Superscripts represent additional information about the network.

i =AQI Reported
C =Collocated
S =Continuous T640 Monitor
M =Maximum Ozone Concentration Site for MSA
m =PM10 Filter Analyzed for Metals
e =Emergency Episode Monitor
P = PWEI Monitor

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CSA/MSA: Charleston-Huntington-Ashland, WV-OH-KY CSA; Huntington-Ashland, WV-KY-OH MSA
401 KAR 50:020 Air Quality Region: Huntington (WV)-Ashland (KY)-Portsmouth-Ironton (OH) Interstate (103)
Site Name: 21st and Greenup
AQS Site ID: 21-019-0002
Location: 122 22nd Street, Ashland, KY 41101
County: Boyd
GPS Coordinates: 38.47676, -82.63137 (NAD 83)
Date Established: April 2, 1978
Inspection Date: December 4, 2017
Inspection By: Shauna Switzer
Site Approval Status: Site and monitors meet all design criteria for the monitoring network.

The monitoring site is located on the west end of the roof of the Valvoline Oil complex building in Ashland, Kentucky. The building is one story tall. The sample inlets are 75 meters from the nearest road. Upon inspection, the sample inlets and monitors were found to be in good condition. The site meets the requirements of 40 CFR 58, Appendices A, C, D and E.

Monitoring Objective:
The monitoring objectives are to determine compliance with National Ambient Air Quality Standards and to measure concentrations of a sub-group of air toxics.

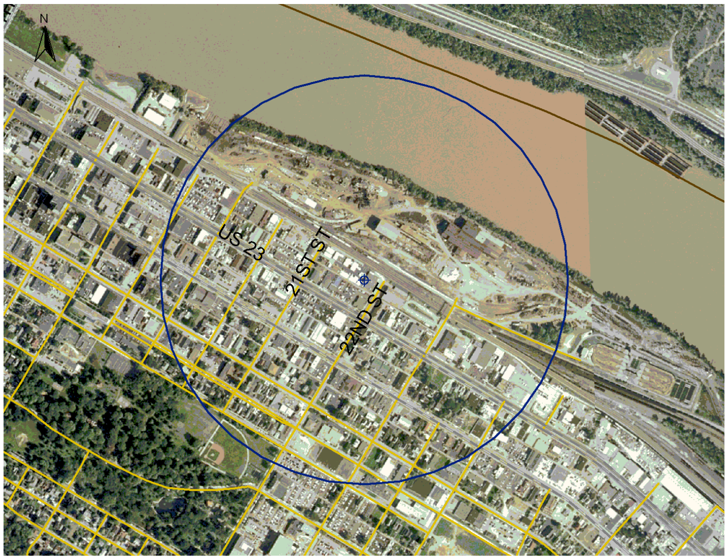
Monitors:

Monitor Type	Inlet Height (meters)	Designation	Analysis Method	Frequency of Sampling
FEM PM_{10}	6.8	SLAMS	Gravimetric	24-hours every sixth day
- Metals PM_{10}		SPM-Other	Determined from the PM_{10} sample using EPA method IO 3.5	Same as PM_{10}
Collocated FEM PM_{10}	6.8	SLAMS	Gravimetric	24-hours every twelfth day
- Collocated Metals PM_{10}		SPM-Other	Determined from the PM_{10} sample using EPA method IO 3.5	24-hours; six samples per year

Quality Assurance Status:
All Quality Assurance procedures have been implemented in accordance with 40 CFR 58, Appendix A.

Area Representativeness:
The site represents maximum concentration on a middle scale for particulates and metals.

Middle Scale: Particulates and Metals



CSA/MSA: Charleston-Huntington-Ashland, WV-OH-KY CSA; Huntington-Ashland, WV-KY-OH MSA
401 KAR 50:020 Air Quality Region: Huntington (WV)-Ashland (KY)-Portsmouth-Ironton (OH) Interstate (103)
Site Name: Ashland Primary (FIVCO)
AQS Site ID: 21-019-0017
Location: FIVCO Health Department, 2924 Holt Street, Ashland, KY 41101
County: Boyd
GPS Coordinates: 38.45934, -82.64041 (NAD 83)
Date Established: January 1, 1999
Inspection Date: December 4, 2017
Inspection By: Shauna Switzer
Site Approval Status: Site and monitors meet all design criteria for the monitoring network.

The monitoring site is a stationary equipment shelter located on the grounds of the health department building in Ashland, Kentucky. The sample inlets are 70 meters from the nearest road. Upon inspection, the sample lines and monitors were found to be in good condition.

Previously, airflow at the site was partially obstructed by tall trees. However, KDAQ and the FIVCO Health Department invested in significant tree removal in November 2016, alleviating siting criteria concerns. The site is operated in accordance with all criteria required by 40 CFR 58, Appendices A, C, D, E, and G.

Monitoring Objective:
The monitoring objectives are to determine compliance with National Ambient Air Quality Standards; to detect elevated pollutant levels for activation of emergency control procedures for nitrogen dioxide, ozone, and sulfur dioxide; and to provide pollutant levels for daily air quality index reporting.

Monitors:

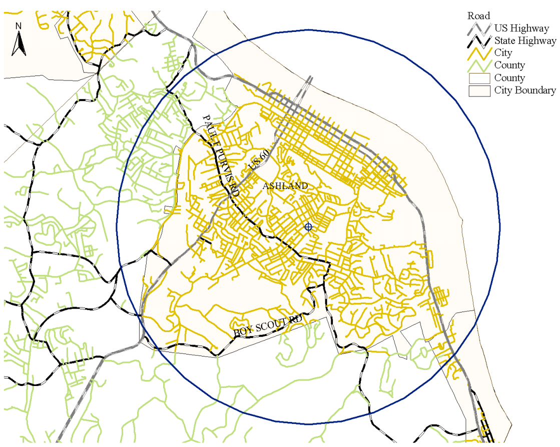
Monitor Type	Inlet Height (meters)	Designation	Analysis Method	Frequency of Sampling
AEM Nitrogen Dioxide (NO_2, NO, NO_x)	3.8	SLAMS AQI EPISODE	Chemiluminescence	Continuously
AEM Sulfur Dioxide	3.8	SLAMS AQI EPISODE PWEI	UV fluorescence	Continuously
AEM Ozone	3.8	SLAMS AQI EPISODE Maximum O^3	UV photometry	Continuously March 1 – October 31
FRM $PM_{2.5}$	4.7	SLAMS	Gravimetric	24-hours every third day
$PM_{2.5}$ Continuous	4.7	SPM AQI	Broadband spectroscopy	Continuously

Meteorological	5.8	Other	AQM grade instruments for wind speed, wind direction, humidity, barometric pressure, and temperature	Continuously

Quality Assurance Status:
All Quality Assurance procedures have been implemented in accordance with 40 CFR 58, Appendix A.

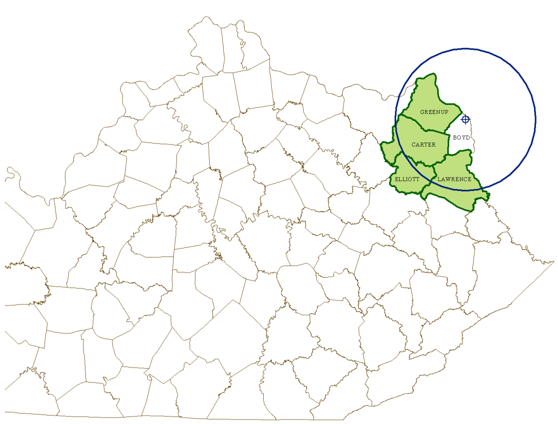
Area Representativeness:
This site represents population exposure on a neighborhood scale for air toxics, ozone, and sulfur dioxide. This site also represents maximum concentrations on a middle scale for particulates, as well as an urban scale for nitrogen dioxide.

Neighborhood Scale: Air Toxics, Ozone, Sulfur Dioxide



Middle Scale: Particulates

Urban Scale: Nitrogen Dioxide



CSA/MSA: Charleston-Huntington-Ashland, WV-OH-KY CSA; Huntington-Ashland, WV-KY-OH MSA
401 KAR 50:020 Air Quality Region: Huntington (WV)-Ashland (KY)-Portsmouth-Ironton (OH) Interstate (103)
Site Name: Worthington
AQS Site ID: 21-089-0007
Location: Scott Street & Center Avenue, Worthington, KY 41183
County: Greenup
GPS Coordinates: 38.548136, -82.731163 (NAD 83)
Date Established: October 12, 1980
Inspection Date: December 4, 2017
Inspection By: Shauna Switzer
Site Approval Status: Site and monitors meet all design criteria for the monitoring network.

The monitoring site is a stationary equipment shelter located on the grounds of a water tower near the intersection of Scott Street and Center Avenue in Worthington, Kentucky. The sample inlets are 16.2 meters from the nearest road. Upon inspection, the sample lines and monitors were found to be in good condition. The site meets the requirements of 40 CFR 58, Appendices A, C, D, and E.

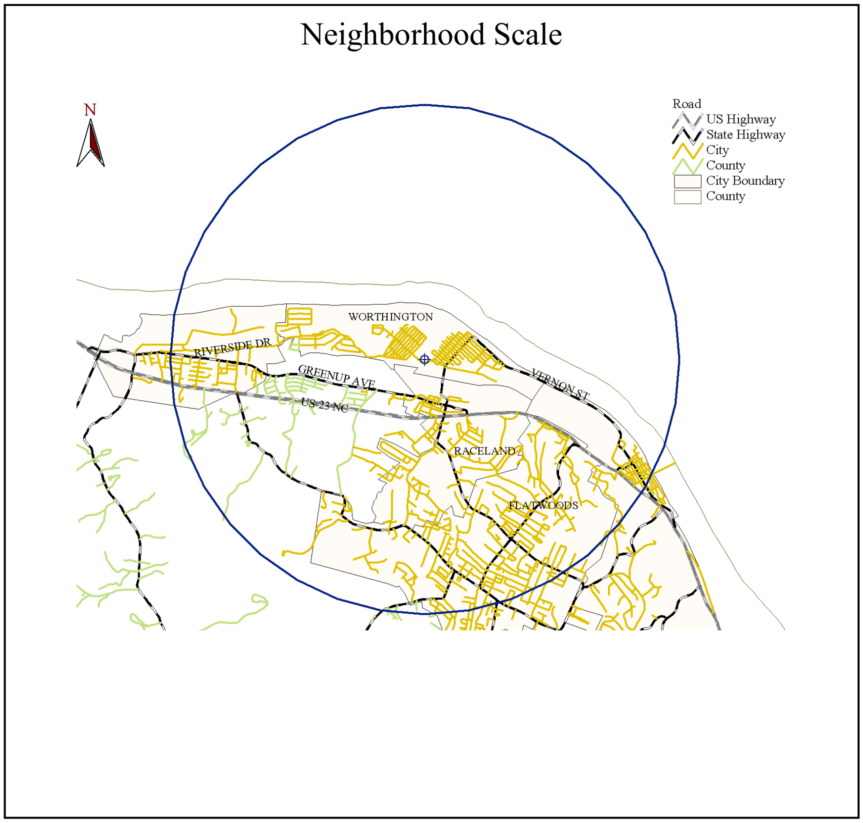
Monitoring Objective:
The monitoring objectives are to determine compliance with National Ambient Air Quality Standards; to detect elevated pollutant levels for activation of emergency control procedures for ozone and sulfur dioxide.

Monitors:

Monitor Type	Inlet Height (meters)	Designation	Analysis Method	Frequency of Sampling
AEM Ozone	4.2	SLAMS EPISODE	UV photometry	Continuously March 1 – October 31
AEM Sulfur Dioxide	4.2	SPM EPISODE	UV fluorescence	Continuously

Quality Assurance Status:
All Quality Assurance procedures have been implemented in accordance with 40 CFR 58, Appendix A.

Area Representativeness:
This site represents population exposure on a neighborhood scale for ozone and sulfur dioxide.



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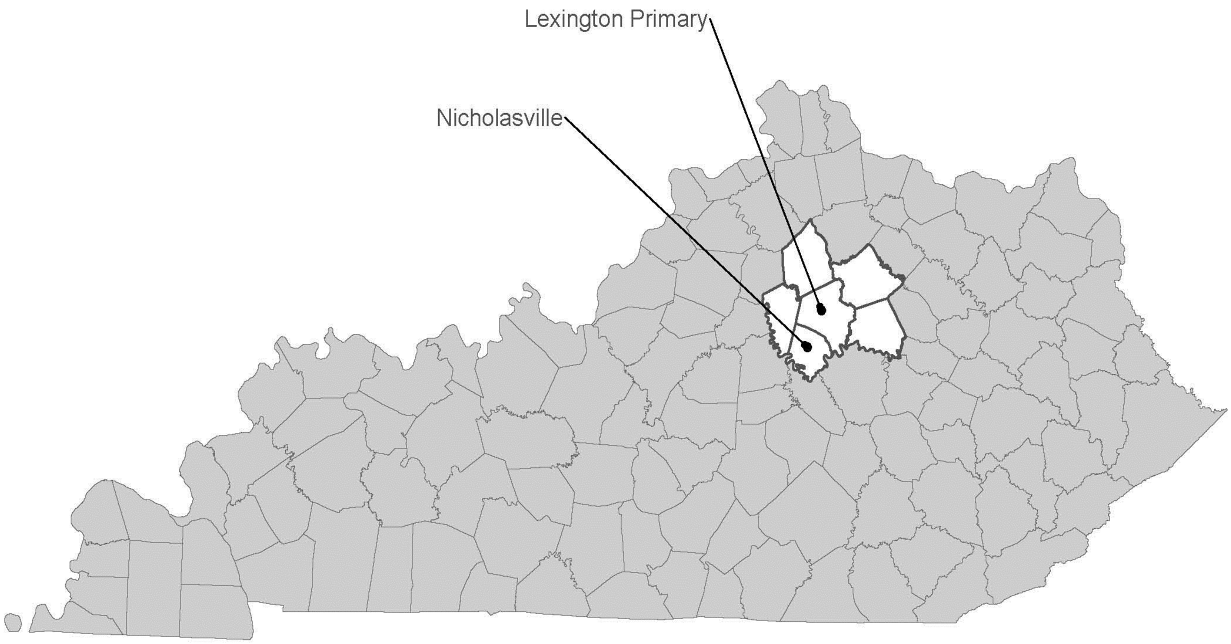
Lexington-Fayette, KY



AQS ID / County	Site Address	PM2.5	Cont. PM2.5	PM10	Cont. PM10	SO2	NO2	NOy	CO	O3	Pb	VOC	Carbonyl	PAH	PM2.5 Spec.	Carbon Spec.	RadNet	Met
21-067-0012 Fayette	650 Newtown Pike Lexington	1	1^{ti}	1^{m}		1^{ieP}	1^{ier}			1^{ieM}		1					1	
21-113-0001 Jessamine	260 Wilson Drive Nicholasville					1				1								1
Totals	**2**	**1**	**1**	**1**		**2**	**1**			**2**		**1**					**1**	**1**

Tallies are equal to the actual number of monitors present. Superscripts represent additional information about the network.

PWEI SO_2 monitor required in CBSA.

i = AQI
r = RA-40 Monitor
t = Continuous TEOM Monitor
M = Maximum Ozone Concentration Site for MSA
m = PM10 Filter Analyzed for Metals
e = Emergency Episode Monitor

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CSA/MSA: Lexington-Fayette-Richmond-Frankfort, KY CSA; Lexington-Fayette, KY MSA
401 KAR 50:020 Air Quality Region: Bluegrass Intrastate (102)
Site Name: Lexington Primary
AQS Site ID: 21-067-0012
Location: Fayette County Health Department, 650 Newtown Pike, Lexington, KY 40508
County: Fayette
GPS Coordinates: 38.06503, -84.49761 (NAD 83)
Date Established: November 8, 1979
Inspection Date: November 17, 2017
Inspection By: Shauna Switzer
Site Approval Status: Site and monitors meet all design criteria for the monitoring network.

The monitoring site is a stationary equipment shelter located on the grounds of the Fayette County Health Department building in Lexington, Kentucky. The sample inlets are 118 meters from the nearest road. Upon inspection, the sample lines and monitors were found to be in good condition. The site meets the requirements of 40 CFR 58, Appendices A, C, D, E and G.

Monitoring Objective:
The monitoring objectives are to determine compliance with National Ambient Air Quality Standards; to detect elevated pollutant levels for activation of emergency control procedures for nitrogen dioxide, ozone, particulates, and sulfur dioxide; and to provide pollutant levels for daily air quality index reporting.

Additionally, the nitrogen dioxide monitor has been approved as a RA-40 monitor. According to CFR, each EPA Regional Administrator is required to collaborate with agencies to establish or designate 40 NO_2 monitoring locations, with a primary focus on protecting susceptible and vulnerable populations.

Monitors:

Monitor Type	Inlet Height (meters)	Designation	Analysis Method	Frequency of Sampling
AEM Ozone	3.8	SLAMS AQI EPISODE Maximum O^3	UV photometry	Continuously March 1 – October 31
AEM Nitrogen Dioxide (NO_2, NO, NO_x)	4.0	SLAMS (RA-40) AQI EPISODE	Chemiluminescence	Continuously
AEM Sulfur Dioxide	3.5	SLAMS AQI EPISODE	UV fluorescence	Continuously
$PM_{2.5}$ TEOM	4.5	SPM AQI	Tapered element oscillating microbalance, gravimetric	Continuously

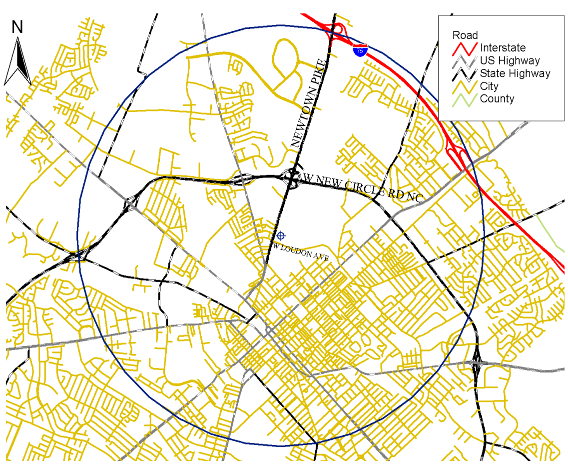
Monitors (continued):

FRM $PM_{2.5}$	2.3	SLAMS	Gravimetric	24-hours every third day
PM_{10}	2.3	SLAMS	Gravimetric	24-hours every sixth day
- PM_{10} Metals		SPM-Other	Determined from the PM_{10} sample using EPA method IO 3.5	Same as PM_{10}
Radiation	1.2	RadNet	RadNet fixed stationary monitor, manual and automated methods	Continuously & 2 weekly filters

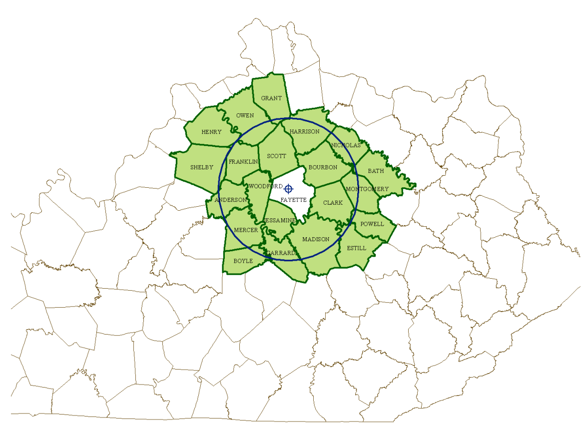
Quality Assurance Status:
All quality assurance procedures have been implemented in accordance with 40 CFR 58, Appendix A.

Area Representativeness:
This site represents population exposure on a neighborhood scale for particulates, sulfur dioxide and ozone. This site also represents population exposure on an urban scale for nitrogen dioxide.

Neighborhood Scale: Particulates, Sulfur Dioxide, Ozone



Urban Scale: Nitrogen Dioxide



CSA/MSA: Lexington-Fayette-Richmond-Frankfort, KY CSA; Lexington-Fayette, KY MSA
401 KAR 50:020 Air Quality Region: Bluegrass Intrastate (102)
Site Name: Nicholasville
AQS Site ID: 21-113-0001
Location: KYTC Maintenance Garage, 260 Wilson Drive, Nicholasville, KY 40356
County: Jessamine
GPS Coordinates: 37.89147, -84.58825 (NAD 83)
Date Established: August 1, 1991
Inspection Date: November 22, 2017
Inspection By: Shauna Switzer
Site Approval Status: Site and monitors meet all design criteria for the monitoring network.

The monitoring site is a stationary equipment shelter located on the grounds of the Kentucky Transportation Cabinet garage in Nicholasville, Kentucky. The sample inlets are 112.3 meters from the nearest road. Upon inspection, the sample inlets and monitors were found to be in good condition. The site meets the requirements of 40 CFR 58, Appendices A, C, D, and E.

Monitoring Objective:
The monitoring objectives are to determine compliance with National Ambient Air Quality Standards and to provide ozone data upwind of the Lexington area.

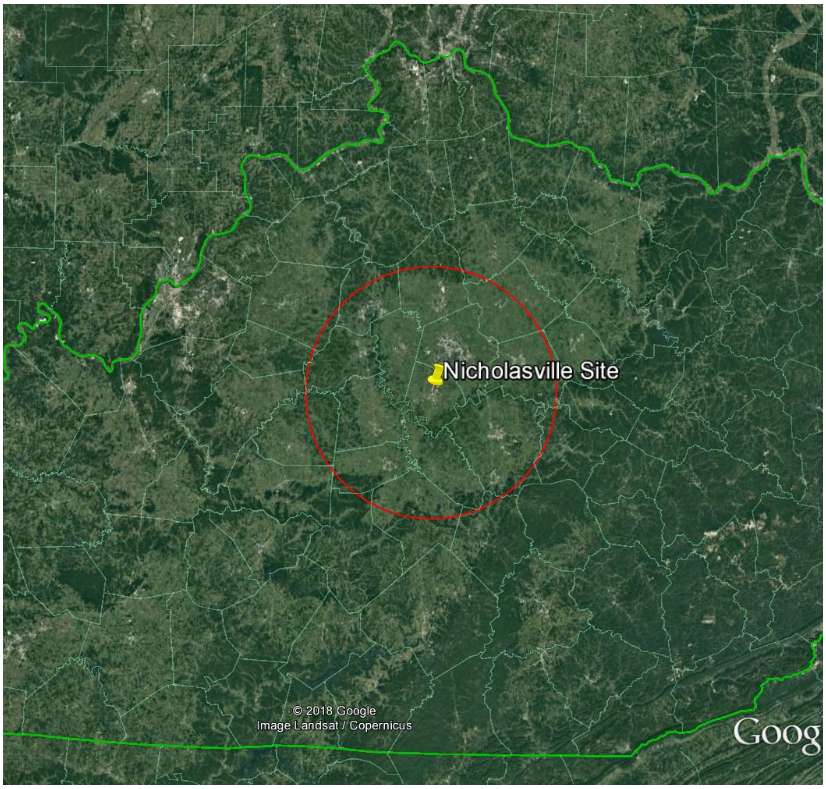
Monitors:

Monitor Type	Inlet Height (meters)	Designation	Analysis Method	Frequency of Sampling
AEM Ozone	3.8	SLAMS	UV photometry	Continuously March 1 – October 31
AEM Sulfur Dioxide	3.9	SPM	UV fluorescence	Continuously
Meteorological	5.6	Other	AQM grade instruments for wind speed, wind direction, temperature, and barometric pressure	Continuously

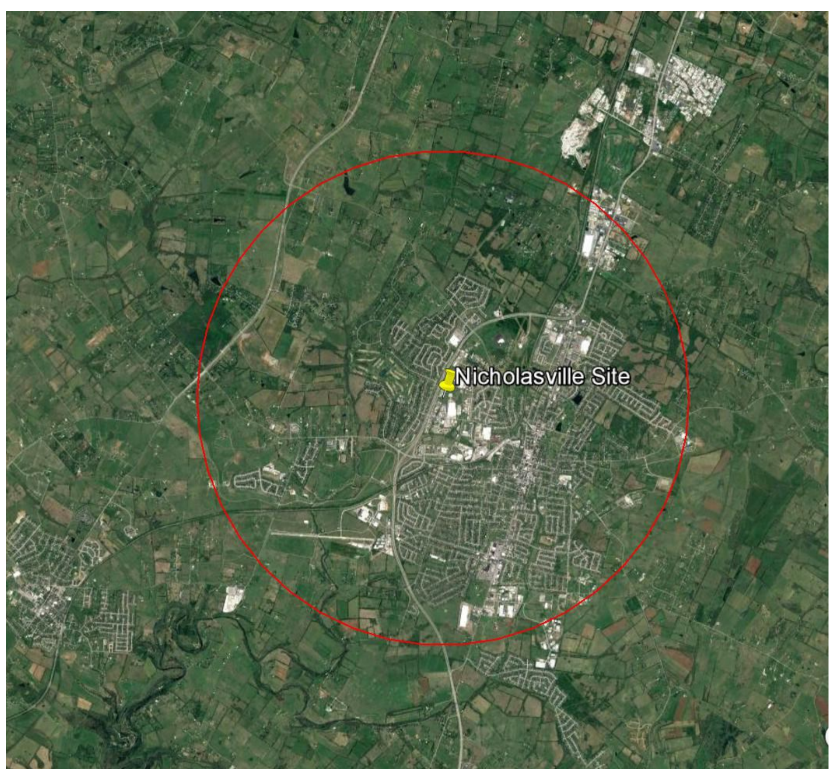
Quality Assurance Status:
All Quality Assurance procedures have been implemented in accordance with 40 CFR 58, Appendix A.

Area Representativeness:
This site represents population exposure on an urban scale.

Urban Scale (50 km): Ozone and Sulfur Dioxide



Urban Scale (4 km): Particulate Matter



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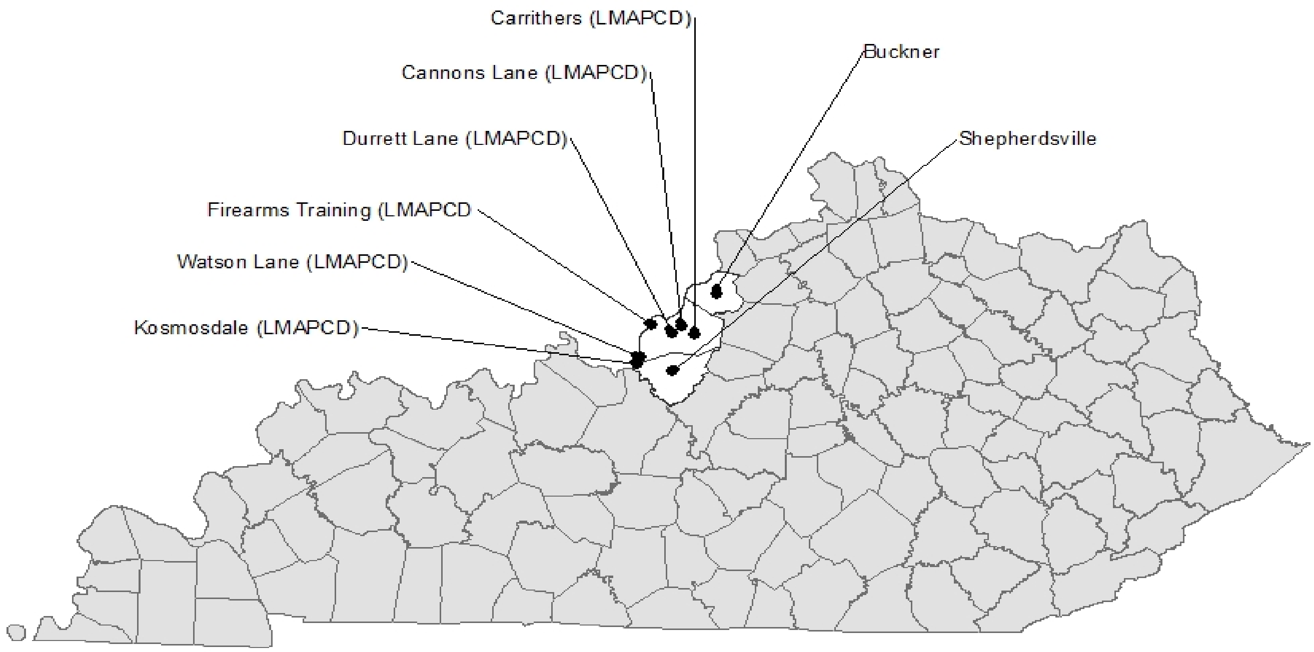
Louisville/Jefferson County, KY-IN



AQS ID / County	Site Address	PM2.5	Cont. PM2.5	PM10	Cont. PM10	SO2	NO2	NOy	CO	O3	Pb	VOC	Carbonyl	PAH	PM2.5 Spec.	Carbon Spec.	RadNet	Met
21-029-0006 Bullitt	2nd & Carpenter St Shepherdsville									1								
21-185-0004 Oldham	1601 South Hwy 393 LaGrange									1^{M}								1
21-111-0051 Jefferson	7201 Watson Ln Louisville (LMAPCD)		$1^{i,S,*}$			1^{i}				1^{i}								1
21-111-0065 Jefferson	15501R Dixie Hwy Louisville (LMAPCD)					1^{i}												1
21-111-0067 Jefferson	2730 Cannons Ln Louisville (LMAPCD)	2^{C}	$1^{i,S,*}$		$1^{i,B}$	1^{i}	1^{i}	1	1^{i}	1^{i}		1^{G}			1	1	1	1
21-111-0075 Jefferson	1517 Durrett Ln Louisville (LMAPCD)	1^{n}	$1^{S,n}$				1^{n}		1^{n}									1^{n}
21-111-0080 Jefferson	4320 Billtown Rd Louisville (LMAPCD)		1^{i}							1^{i}								1
21-111-1041 Jefferson	4201 Algonquin Pkwy Louisville (LMAPCD)		$1^{i,S,*}$		$1^{i,S}$	1^{i}						1^{G}						1
Totals	**8**	**3**	**5**		**2**	**4**	**2**	**1**	**2**	**5**		**2**			**1**	**1**	**1**	**7**

Tallies are equal to the actual number of monitors present. Superscripts represent additional information about the network.

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C =Collocated
S =Continuous T640 Monitor
* =Eligible for PM2.5 NAAQS Comparisons
M =Maximum Ozone Concentration Site for MSA
G =Auto GC
i =AQI Reported
n =Near-Road Monitor

Rev. 6/22/18

CSA/MSA: Louisville/Jefferson County-Elizabethtown-Madison, KY-IN CSA; Louisville/Jefferson County, KY-IN MSA
401 KAR 50:020 Air Quality Region: North Central Kentucky Intrastate (104)
Site Name: Shepherdsville
AQS Site ID: 21-029-0006
Location: East Joe B. Hall Avenue & Carpenter Streets, Shepherdsville, KY 40165
County: Bullitt
GPS Coordinates: 37.98629, -85.71192 (NAD 83)
Date Established: January 30, 1992
Inspection Date: November 22, 2017
Inspection By: Shauna Switzer
Site Approval Status: Site and monitors meet all design criteria for the monitoring network.

The monitoring site is a stationary equipment shelter located in a fenced-in area near the intersection of Second and Carpenter Streets in Shepherdsville, Kentucky. The sample inlets are 58 meters from the nearest road. Upon inspection, the sample lines and monitors were found to be in good condition. The site meets the requirements of 40 CFR 58, Appendices A, C, D, and E.

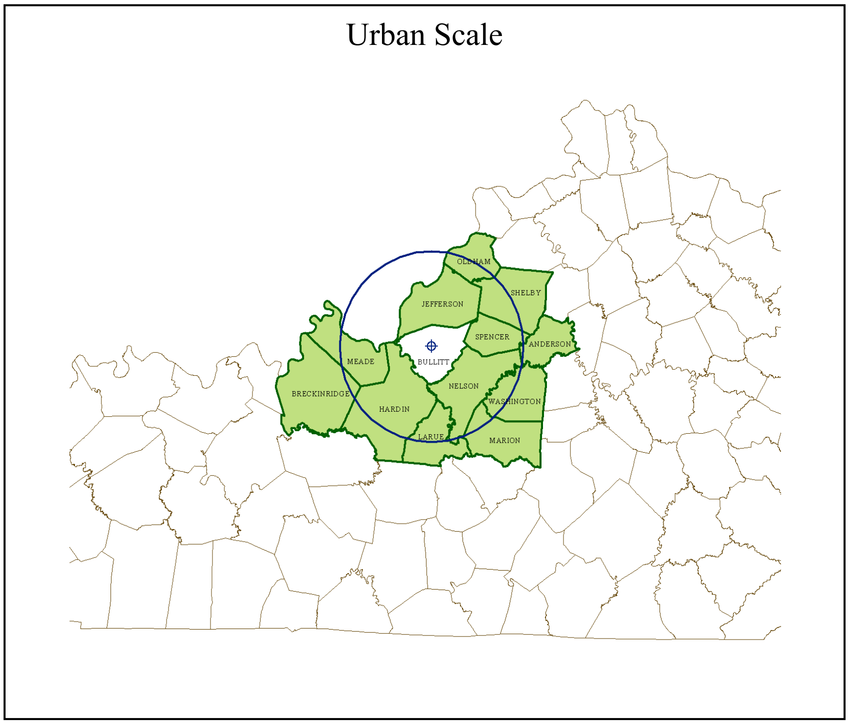
Monitoring Objective:
The monitoring objectives are to determine compliance with National Ambient Air Quality Standards.

Monitors:

Monitor Type	Inlet Height (meters)	Designation	Analysis Method	Frequency of Sampling
AEM Ozone	4.0	SLAMS	UV photometry	Continuously March 1 – October 31

Quality Assurance Status:
All Quality Assurance procedures have been implemented in accordance with 40 CFR 58, Appendix A.

Area Representativeness:
This site represents population exposure on an urban scale for ozone.



CSA/MSA: Louisville/Jefferson County-Elizabethtown-Madison, KY-IN CSA; Louisville/Jefferson County, KY-IN MSA
401 KAR 50:020 Air Quality Region: North Central Kentucky Intrastate (104)
Site Name: Buckner
AQS Site ID: 21-185-0004
Location: KYTC Maintenance Facility, 1601 South Hwy 393, LaGrange, KY 40031
County: Oldham
GPS Coordinates: 38.40020, -85.44428 (NAD 83)
Date Established: May 1, 1981
Inspection Date: November 22, 2017
Inspection By: Shauna Switzer
Site Approval Status: Site and monitor meet all design criteria for the monitoring network.

The monitoring site is a stationary equipment shelter located on the grounds of the Kentucky Transportation Cabinet Highway garage in Buckner, Kentucky. The sample inlet is 51 meters from the nearest road. Upon inspection, the sample line and monitor were found to be in good condition. The site meets the requirements of 40 CFR 58, Appendices C, D, and E.

Monitoring Objective:
The monitoring objectives are to determine compliance with National Ambient Air Quality Standards.

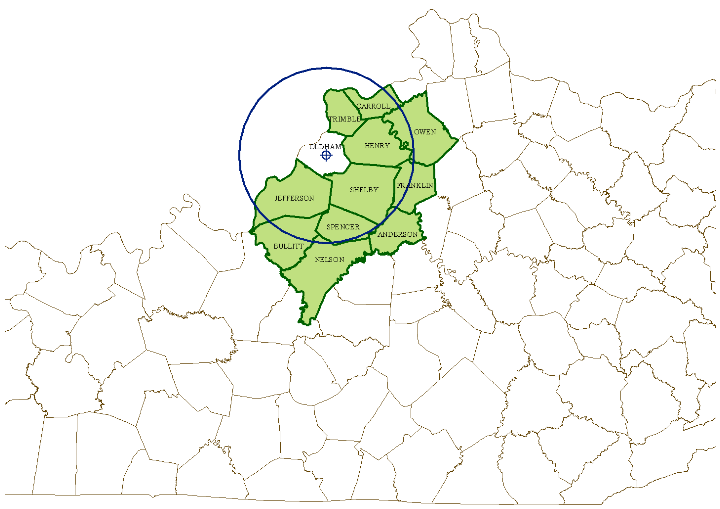
Monitors:

Monitor Type	Inlet Height (meters)	Designation	Analysis Method	Frequency of Sampling
AEM Ozone	3.8	SLAMS Maximum O^3	UV photometry	Continuously March 1 – October 31
Meteorological	5.6	Other	AQM grad instruments for wind speed, wind direction, humidity, barometric pressure, and temperature	Continuously

Quality Assurance Status:
All Quality Assurance procedures have been implemented in accordance with 40 CFR 58, Appendix A.

Area Representativeness:
This site represents maximum concentrations on an urban scale.

Urban Scale



CSA/MSA: Louisville/Jefferson County-Elizabethtown-Madison, KY-IN CSA; Louisville/Jefferson County, KY-IN MSA
401 KAR 50:020 Air Quality Region: Louisville Interstate (078)
Site Name: Watson Lane
AQS Site ID: 21-111-0051
Location: 7201 Watson Lane, Louisville, KY 40272
County: Jefferson
GPS Coordinates: 38.06091, -85.89804 (NAD 83)
Date Established: July 16, 1992
Inspection Date: December 15, 2017
Inspection By: Shauna Switzer
Site Approval Status: Site and monitors meet all design criteria for the monitoring network.

The monitoring site is a stationary equipment shelter located on the grounds of the Watson Lane Elementary School in Louisville, Kentucky. The sample inlets are 4 meters above ground level and 30.3 meters from the nearest road. Upon inspection, the sample lines and monitors were found to be in good condition. The air monitoring site meets the criteria established by 40 CFR Part 58, Appendices C, D, E and G.

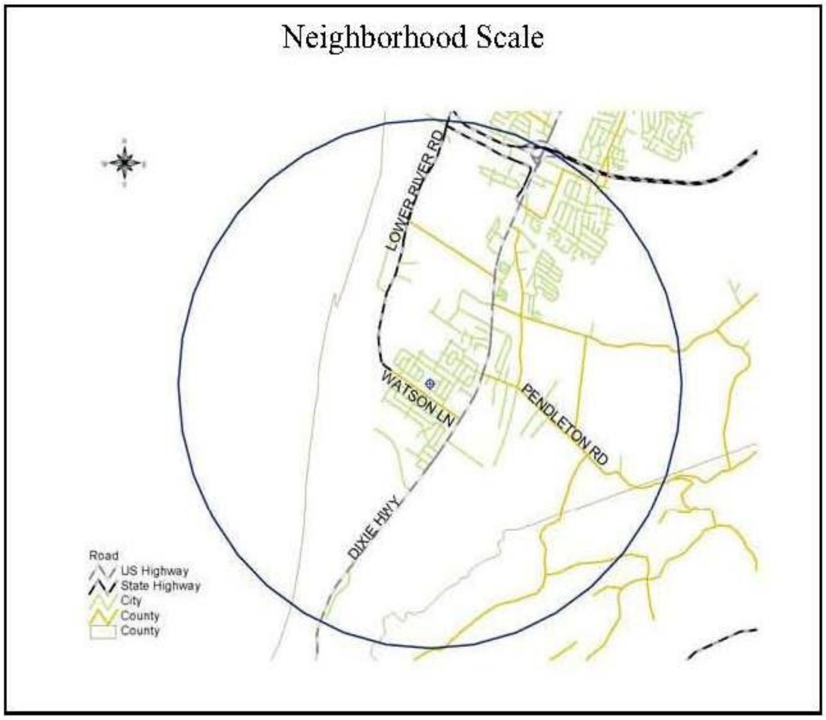
Monitoring Objective:
The monitoring objectives are to determine compliance with National Ambient Air Quality Standards and to provide pollution levels for daily index reporting.

Monitors:

Monitor Type	Inlet Height (meters)	Designation	Analysis Method	Frequency of Sampling
AEM Ozone	4.0	SLAMS AQI	UV photometry	Continuously March 1 – October 31
PM2.5 Continuous	4.6	SLAMS AQI	Broadband Spectroscopy	Continuously
AEM Sulfur Dioxide	4.0	SLAMS	UV fluorescence	Continuously
Meteorological	4.6	Other	AQM grade instruments for wind speed and wind direction. Not reported to AQS.	Continuously

Quality Assurance Status:
All Quality Assurance procedures have been implemented in accordance with 40 CFR 58, Appendix A.

Area Representativeness:
This site represents population exposure on a neighborhood scale for ozone and particulates. This site also represents maximum concentrations on a neighborhood scale for SO_2.



CSA/MSA: Louisville/Jefferson County-Elizabethtown-Madison, KY-IN CSA; Louisville/Jefferson County, KY-IN MSA
401 KAR 50:020 Air Quality Region: Louisville Interstate (078)
Site Name: Kosmosdale
AQS Site ID: 21-111-0065
Location: 15501R Dixie Highway, Louisville, KY 40272
County: Jefferson
GPS Coordinates: 38.0296139, -85.911389 (NAD 83)
Date Established: TBD
Inspection Date: TBD
Inspection By: TBD
Site Approval Status: TBD

Due to the need for additional characterization of ambient air quality in the vicinity of the Jefferson County SO_2 nonattainment area in southwestern Jefferson County, a new site will be established. This site, named Kosmosdale, will be located approximately ¼ mile south-southwest of the Kosmos Cement Co. facility and approximately one mile south of the Jefferson County SO_2 nonattainment area. The operational date for this site has been delayed due to delays in the SIP submittal for the Southwest Jefferson County SO_2 non-attainment area.

Monitoring Objective:
The monitoring objectives are to determine compliance with National Ambient Air Quality Standards and to provide pollution levels for daily index reporting.

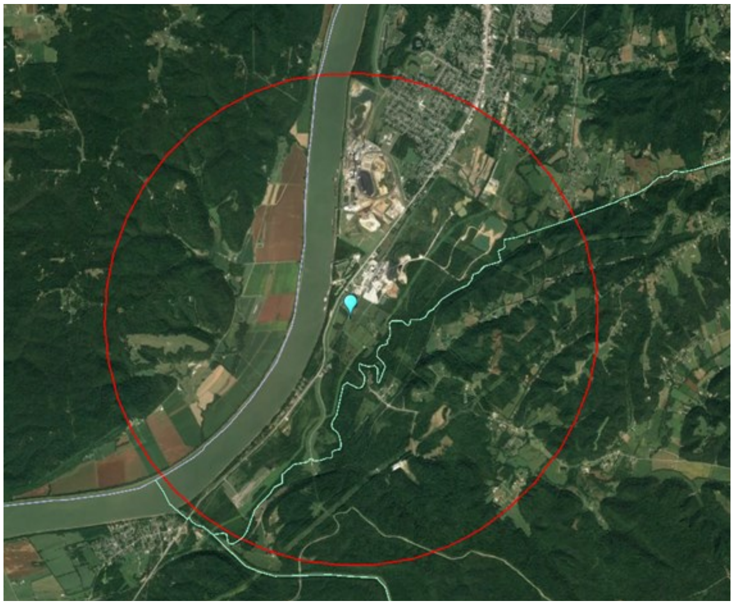
Monitors:

Monitor Type	Inlet Height (meters)	Designation	Analysis Method	Frequency of Sampling
AEM Sulfur Dioxide	TBD	SLAMS	UV fluorescence	Continuously
Meteorological	TBD	Other	AQM grade instruments for wind speed, wind direction, temperature, and humidity. Not reported to AQS; thus, there is no designation.	Continuously

Quality Assurance Status:
All Quality Assurance procedures will be implemented in accordance with 40 CFR 58, Appendix A.

Area Representativeness:
This site will represent population exposure on a neighborhood scale for sulfur dioxide.

Neighborhood Scale: Sulfur Dioxide



CSA/MSA: Louisville/Jefferson County-Elizabethtown-Madison, KY-IN CSA; Louisville/Jefferson County, KY-IN MSA
401 KAR 50:020 Air Quality Region: Louisville Interstate (078)
Site Name: Cannons Lane
AQS Site ID: 21-111-0067
Location: Bowman Field, 2730 Cannons Lane, Louisville, KY 40204
County: Jefferson
GPS Coordinates: 38.2288760, -85.654520 (NAD 83)
Date Established: July 1, 2008
Inspection Date: December 15, 2017
Inspection By: Shauna Switzer
Site Approval Status: EPA SLAMS approval on December 22, 2008; EPA NCore approval on October 30, 2009.

The station is located on property leased by LMAPCD. The site is located in the NE quadrant of Jefferson County and is approximately 9 km from the urban core of Metro Louisville. The site was originally established as a SLAMS site in 2008 and became a NCore site in 2009. In December 2010, a solar electric array designed to produce approximately 6,336 kWh per year was installed. The array provides over 50% of the power used by the air monitoring station. Upon inspection, the sample lines and monitors were found to be in good condition. The air monitoring site meets the criteria of 40 CFR Part 58, Appendices A, C, D, E and G.

Monitoring Objective:

The NCore Network addresses the following monitoring objectives:

- timely reporting of data to the public through AIRNow, air quality forecasting, and other public reporting mechanisms
- support development of emission strategies through air quality model evaluation and other observational methods
- accountability of emission strategy progress through tracking long-term trends of criteria and non-criteria pollutants and their precursors
- support long-term health assessments that contribute to ongoing reviews of the National Ambient Air Quality Standards (NAAQS)
- compliance through establishing nonattainment/attainment areas by comparison with the NAAQS
- support multiple disciplines of scientific research, including public health, atmospheric, and ecological.

Monitors:

Monitor Type	Inlet Height (meters)	Designation	Analysis Method	Frequency of Sampling
Carbon Monoxide	4.3	NCore SLAMS AQI	Automated Reference Method utilizing trace level non-dispersive infrared analysis.	Continuously
Nitrogen Dioxide (NO_2)	4.3	NCore SLAMS AQI	Cavity Attenuated Phase Shift Spectrometry	Continuously
Total Reactive Nitrogen (NO/NO_y)	10.0	NCore PAMS	Automated method utilizing trace level chemiluminescence analysis.	Continuously
Ozone	4.3	NCore PAMS SLAMS AQI	Automated Equivalent Method utilizing UV photometry analysis.	Continuously
Sulfur Dioxide	4.3	NCore SLAMS AQI	Automated Equivalent Method utilizing trace level UV fluorescence analysis.	Continuously
$PM_{2.5}$ and PM_{10} Continuous - PM_{Coarse} (PM_{10}-$PM_{2.5}$)	TBD	NCore SLAMS AQI	Broadband Spectroscopy	Continuously
$PM_{2.5}$ Speciation	2.2	NCore SLAMS	Multi-Species manual collection method utilizing thermal optical ion chromatography, gravimetric, and X-ray fluorescence.	24-hours every third day
$PM_{2.5}$ Carbon Speciation	2.4	NCore SLAMS	Multi-species manual collection method utilizing thermal optical and gravimetric analyses.	24-hours every third day
FRM $PM_{2.5}$	2.4	NCore SLAMS	Manual reference method utilizing gravimetric analysis	24-hours every third day
FRM $PM_{2.5}$ Collocated	TBD (Install 2019)	NCore SLAMS QA Collocated	Manual reference method utilizing gravimetric analysis	24-hours every sixth day
Volatile Organic Compounds	TBD (Install 2019)	PAMS	Automatic gas chromatograph with flame ionization detection	Continuously

Monitors (continued):

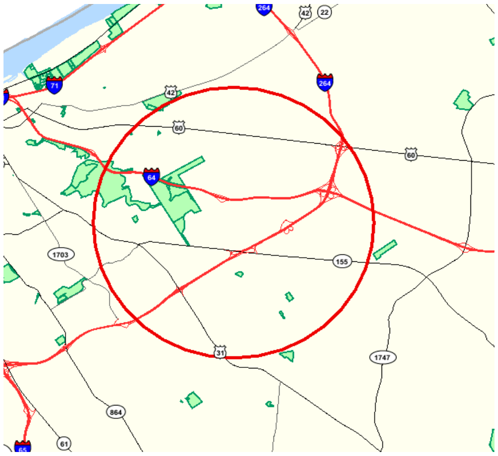
Monitor Type	Inlet Height (meters)	Designation	Analysis Method	Frequency of Sampling
Meteorological	9.3	NCore PAMS	Air Quality Measurements approved instrumentation for wind speed, wind direction, humidity, and temperature	Continuously
-Ceilometer	TBD (Install 2019)	PAMS	Pulsed diode laser light detection and ranging (LIDAR)	Continuously
-Solar Radiation	5.0	NCore PAMS	Air Quality Measurements approved instrumentation for solar radiation	Continuously
-Rain Gauge	1.8	NCore PAMS	Air Quality Measurements approved instrumentation for precipitation	Continuously
Radiation	1.5	RadNet	RadNet fixed station air monitor, manual and automated methods	Continuously + 2 weekly filters

Quality Assurance Status:
All Quality Assurance procedures have been implemented in accordance with 40 CFR 58, Appendix A. The District's current Quality Assurance Project Plan covers trace-level O_3, NO_x, SO_2, and CO, as well as $PM_{2.5}$ speciation, lead, and meteorological measurements. Standard operating procedures for trace-level CO, NO_x, NO_y, SO_2, O_3, $PM_{2.5}$, and meteorological measurements have been developed. Additional standard operating procedures manuals will be adopted or developed for new instrumentation.

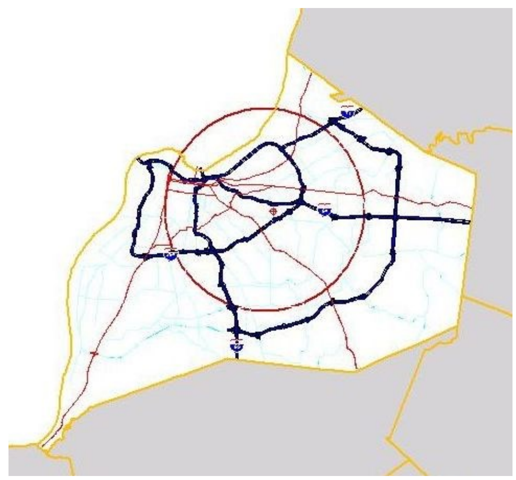
Area Representativeness:
The air monitoring equipment at the Cannon's Lane NCore station is specifically located at the urban and neighborhood scales. These scales are generally the most representative of the expected population exposures that occur throughout metropolitan areas.

Pollutant	Spatial Scale	Comments
Ozone	Neighborhood	
NO_x /NO_y	Neighborhood and Urban Scale	10 km radius
Carbon Monoxide	Neighborhood Scale	4 km radius
SO_2	Urban Scale	50 km radius
Particulates	Urban	50 km radius
Radiation	Urban	50 km radius

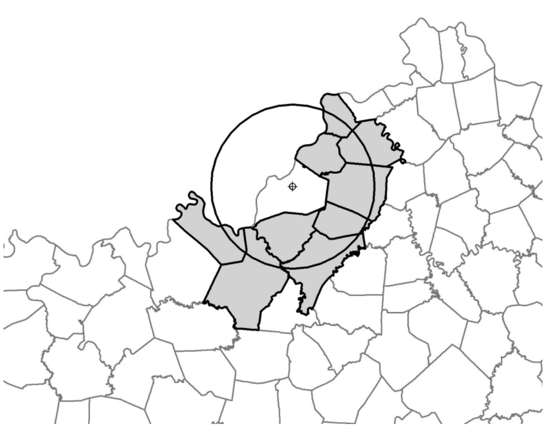
Neighborhood Scale:
Carbon Monoxide and Ozone



Neighborhood and Urban Scales:
(10 km radius)
Nitrogen Oxides



Urban Scale:
Particulates, Sulfur Dioxide, and Radiation



CSA/MSA: Louisville/Jefferson County-Elizabethtown-Madison, KY-IN CSA; Louisville/Jefferson County, KY-IN MSA
401 KAR 50:020 Air Quality Region: Louisville Interstate (078)
Site Name: Durrett Lane (Near-Road Site)
AQS Site ID: 21-111-0075
Location: 1517 Durrett Lane, Louisville, KY 40213
County: Jefferson
GPS Coordinates: 38.193632, -85.711950 (NAD 83)
Date Established: January 1, 2014
Inspection Date: December 15, 2017
Inspection By: Shauna Switzer
Site Approval Status: Site and monitors meet all design criteria for the monitoring network.

On February 9, 2010, the EPA released a new NO_2 Final Rule and a new set of monitoring requirements. Under the new monitoring requirements, State and Local agencies are required to establish near-road monitoring stations based upon core based statistical area (CBSA) populations and traffic metrics. The Louisville/Jefferson County, KY-IN MSA is required to establish not only a near-road nitrogen dioxide monitor, but also near-road $PM_{2.5}$ and carbon monoxide monitors. In response, LMAPCD has established a multi-pollutant near-road site that includes instrumentation to measure nitrogen dioxide, $PM_{2.5}$, carbon monoxide, and meteorology. The specific site was chosen following the development of a formal site proposal and a 30-day comment public period in April 2013. Data collection at the site began in January 2014. More information regarding near-road monitoring can be found in the appendices of this Annual Network Plan.

Monitoring Objective:
The monitoring objective will be to determine compliance with National Ambient Air Quality Standards for nitrogen dioxide, carbon monoxide, and particulate matter.

Monitors:

Monitor Type	Inlet Height (meters)	Designation	Analysis Method	Frequency of Sampling
AEM Nitrogen Dioxide (NO_2)	4.2	SLAMS	Cavity Attenuated Phase Shift Spectroscopy	Continuously
Carbon Monoxide	4.2	SLAMS	Automated Reference Method utilizing trace-level non-dispersive infrared analysis	Continuously
FRM $PM_{2.5}$	4.7	SLAMS	Manual Reference Method utilizing gravimetric analysis	One sample every third day
Meteorological	11.0	Other	AQM grade instruments for wind speed, wind direction, humidity, and temperature	Continuously
PM2.5 Continuous	TBD (Install 2019)	SPM	Broadband Spectroscopy	Continuously

Quality Assurance Status:
All Quality Assurance procedures will be implemented in accordance with 40 CFR 58, Appendix A.

Area Representativeness:
The site represents maximum concentrations on a middle scale.

Middle Scale

CSA/MSA: Louisville/Jefferson County-Elizabethtown-Madison, KY-IN CSA; Louisville/Jefferson County, KY-IN MSA
401 KAR 50:020 Air Quality Region: Louisville Interstate (078)
Site Name: Carrithers Middle School
AQS Site ID: 21-111-0080
Location: 4320 Billtown Road, Louisville, KY 40291
County: Jefferson
GPS Coordinates: 38.182511, -85.574167 (NAD 83)
Date Established: January 9, 2018
Inspection Date: TBD
Inspection By: TBD
Site Approval Status: TBD

Due to Jefferson County Public School's plan for significant modification to the Bates Elementary property, the Bates site was retired in early 2018. A new site was established on the ground of Carrithers Middle School, which is located three miles to the north of the Bates Elementary School site. The instrumentation from Bates was transferred to Carrithers and the new site became operational on 1/9/2018.

Monitoring Objective:
The monitoring objectives are to determine compliance with National Ambient Air Quality Standards and to provide pollution levels for daily index reporting.

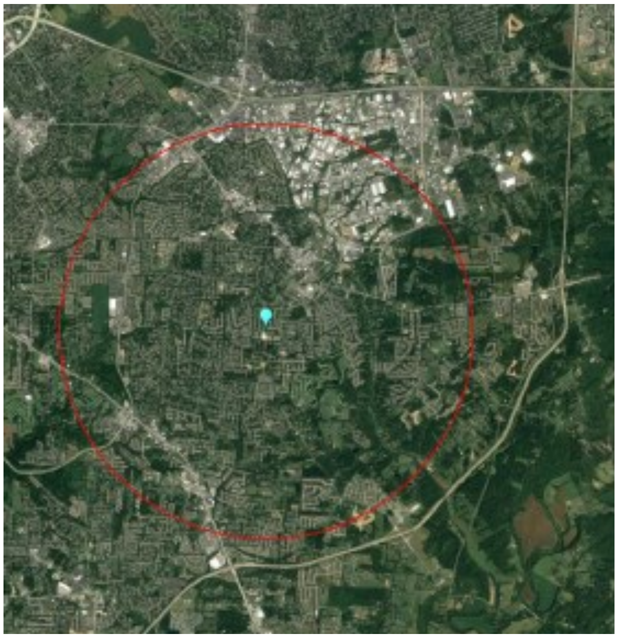
Monitors:

Monitor Type	Inlet Height (meters)	Designation	Analysis Method	Frequency of Sampling
AEM Ozone	TBD	SLAMS AQI	UV photometry	Continuously March 1 – October 31
$PM_{2.5}$ Continuous	TBD	SPM AQI	Broadband Spectroscopy	Continuously
Meteorological	TBD	Other	AQM grade instruments for wind speed, wind direction, temperature, and humidity. Not reported to AQS; thus, there is no designation.	Continuously

Quality Assurance Status:
All Quality Assurance procedures will be implemented in accordance with 40 CFR 58, Appendix A.

Area Representativeness:
This site also represents population exposure on a neighborhood scale for ozone and fine particulates.

Neighborhood Scale: Particulates and Ozone



CSA/MSA: Louisville/Jefferson County-Elizabethtown-Madison, KY-IN CSA; Louisville/Jefferson County, KY-IN MSA
401 KAR 50:020 Air Quality Region: Louisville Interstate (078)
Site Name: Firearms Training
AQS Site ID: 21-111-1041
Location: 4201 Algonquin Parkway, Louisville, KY 40211
County: Jefferson
GPS Coordinates: 38.23158, -85.82675 (NAD 83)
Date Established: April 13, 1978
Inspection Date: December 15, 2017
Inspection By: Shauna Switzer
Site Approval Status: Site and monitor meet all design criteria for the monitoring network.

The monitoring site is a stationary equipment shelter located on the grounds of the Firearms Training Center in Louisville, Kentucky. The sample inlet is 4.5 meters above ground level and 53.5 meters from the nearest road. Upon inspection, the sample lines and monitors were found to be in good condition. The air monitoring site meets the criteria established by 40 CFR Part 58, Appendices C, D, E and G.

LMAPCD replaced the existing shelter with a new, larger shelter in September, 2017 to house a continuous Toxics Monitor (Auto GC). Particulate instruments were transferred from Southwick Community Center site to the Firearms Training site. The particulate transfer was completed by January 1, 2018.

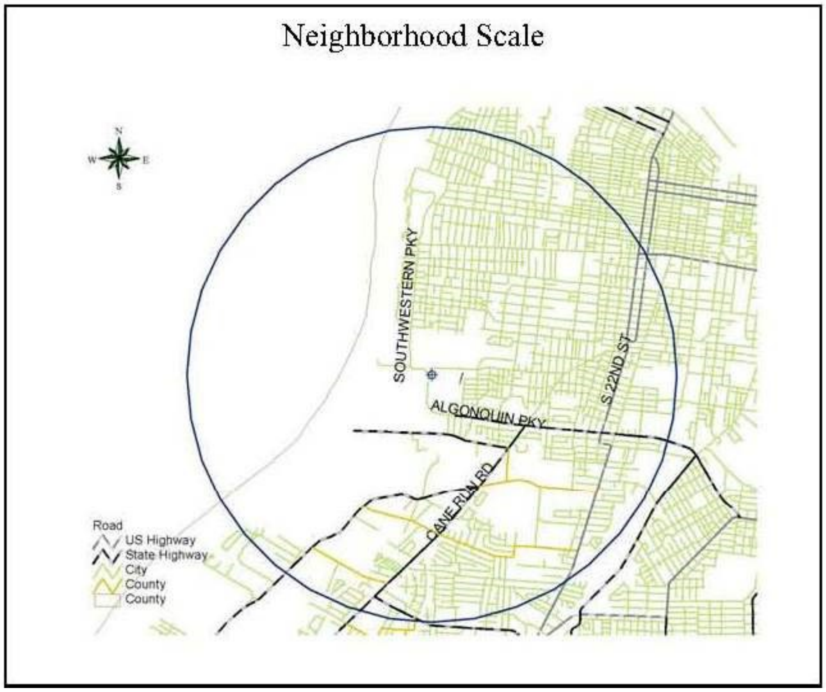
Monitoring Objective:
The monitoring objectives are to determine compliance with National Ambient Air Quality Standards and to detect episode levels for the activation of emergency control procedures.

Monitors:

Monitor Type	Inlet Height (meters)	Designation	Analysis Method	Frequency of Sampling
$PM_{2.5}$ & PM_{10} Contin-uous	TBD	SLAMS AQI	Broadband Spectroscopy (TAPI T640x)	Continuously
AEM Sulfur Dioxide	4.0	SLAMS	UV Fluorescence	Continuously
Volatile Organic Car-bon	TBD	SPM	Automatic gas chromatograph with flame ionization detection	Continuously
Meteorological	TBD	Other	AQM grade instruments for wind speed, wind direction, temperature, barometric pressure, and humidity.	Continuously

Quality Assurance Status:
All Quality Assurance procedures have been implemented in accordance with 40 CFR 58, Appendix A.

Area Representativeness:
This site represents population exposure on a neighborhood scale.



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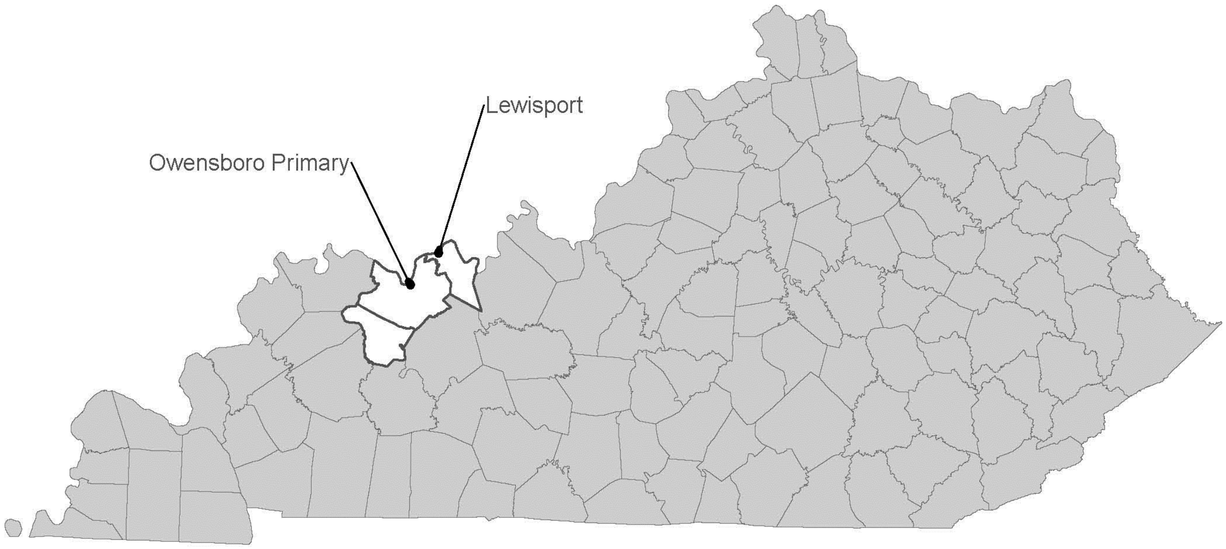
Owensboro, KY



AQS ID / County	Site Address	PM2.5	Cont. PM2.5	PM10	Cont. PM10	SO2	NO2	NOy	CO	O3	Pb	VOC	Carbonyl	PAH	PM2.5 Spec.	Carbon Spec.	RadNet	Met
21-059-0005 Daviess	716 Pleasant Valley Rd. Owensboro	1	1^{Sei}			1^{ei}	1^{ei}			1^{ei}								1
21-091-0012 Hancock	Second & Caroline St. Lewisport									1^{M}								
Totals	**2**	**1**	**1**			**1**	**1**			**2**								**1**

Tallies are equal to the actual number of monitors present. Superscripts represent additional information about the network.

e = Emergency Episode Monitor

S = Continuous T640 Monitor

i = AQI Reported

M = Maximum Ozone Concentration Site for MSA

Rev. 5/1/16

CSA/MSA: Owensboro, KY MSA
401 KAR 50:020 Air Quality Region: Evansville-Owensboro-Henderson Interstate (077)
Site Name: Owensboro Primary
AQS Site ID: 21-059-0005
Location: 716 Pleasant Valley Road, Owensboro, KY 42303
County: Daviess
GPS Coordinates: 37.780776, -87.075307 (NAD 83)
Date Established: December 1, 1970
Inspection Date: December 20, 2017
Inspection By: Shauna Switzer
Site Approval Status: Site and monitors meet all design criteria for the monitoring network.

The monitoring site is a stationary equipment shelter located on the grounds behind the Wyndall's Shopping Center in Owensboro, Kentucky. The sample inlets are 48.5 meters from the nearest road. Upon inspection, the sample lines and monitors were found to be in good condition. The site meets the requirements of 40 CFR 58, Appendices A, C, D, E and G.

Monitoring Objective:
The monitoring objectives are to determine compliance with National Ambient Air Quality Standards; to detect emergency pollution levels of criteria pollutants for activation of emergency control procedures. While not required for the CBSA, the site also provide levels of pollutants for daily index reporting.

Monitors:

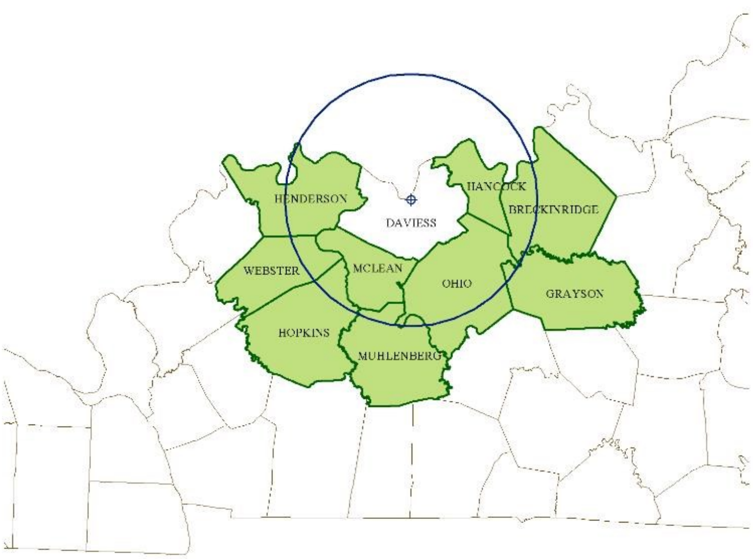
Monitor Type	Inlet Height (meters)	Designation	Analysis Method	Frequency of Sampling
AEM Nitrogen Dioxide (NO_2, NO, NO_x)	3.5	SLAMS EPISODE AQI	Chemiluminescence	Continuously
AEM Ozone	3.5	SLAMS EPISODE AQI	UV photometry	Continuously March 1 – October 31
FRM $PM_{2.5}$	2.2	SLAMS	Gravimetric	24-hours every third day
$PM_{2.5}$ Continuous	4.6	SPM EPISODE AQI	Broadband Spectroscopy	Continuously
AEM Sulfur Dioxide	3.5	SLAMS PWEI EPISODE AQI	UV fluorescence	Continuously
Meteorological	5.4	Other	AQM grade instruments for wind speed, wind direction, humidity, barometric pressure and temperature	Continuously

Quality Assurance Status:
All Quality Assurance procedures have been implemented in accordance with 40 CFR 58, Appendix A.

Area Representativeness:
This site represents population exposure on a neighborhood scale for particulates, ozone, and sulfur dioxide. This site also represents population exposure on an urban scale for nitrogen dioxide.

Neighborhood Scale: Ozone, Sulfur Dioxide, Particulates

Urban Scale: Nitrogen Dioxide



CSA/MSA: Owensboro, KY MSA
401 KAR 50:020 Air Quality Region: Evansville-Owensboro-Henderson Interstate (077)
Site Name: Lewisport
AQS Site ID: 21-091-0012
Location: Community Center Drive & First Street, Lewisport, KY 42351
County: Hancock
GPS Coordinates: 37.93829, -86.89719 (NAD 83)
Date Established: September 5, 1980
Inspection Date: December 20, 2017
Inspection By: Shauna Switzer
Site Approval Status: Site and monitor meet all design criteria for the monitoring network.

The monitoring site is a stationary equipment shelter located on the athletic fields of the former Lewisport Consolidated Elementary School in Lewisport, Kentucky. The sample inlet is 55.3 meters from the nearest road. Upon inspection, the sample line and monitor were found to be in good condition. The site meets the requirements of 40 CFR 58, Appendices A, C, D, and E.

Monitoring Objective:
The monitoring objectives are to determine compliance with National Ambient Air Quality Standards.

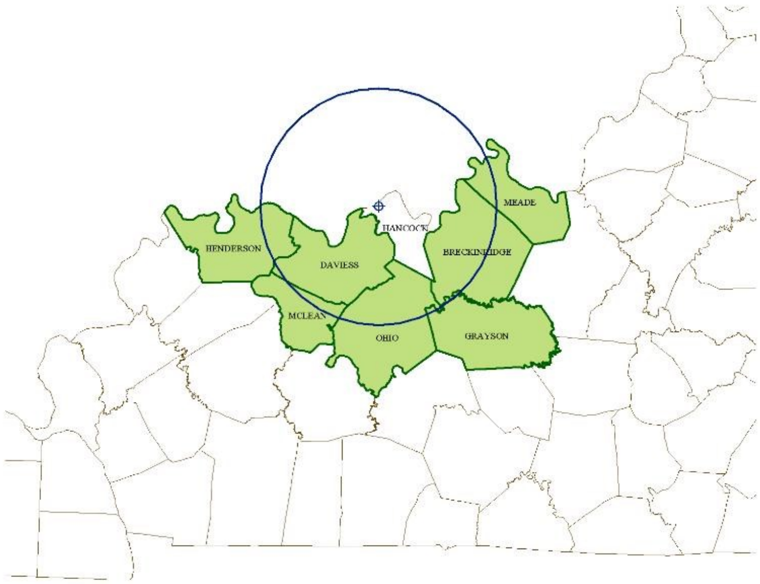
Monitors:

Monitor Type	Inlet Height (meters)	Designation	Analysis Method	Frequency of Sampling
AEM Ozone	3.7	SLAMS Maximum O_3	UV photometry	Continuously March 1 – October 31

Quality Assurance Status:
All Quality Assurance procedures have been implemented in accordance with 40 CFR 58, Appendix A.

Area Representativeness:
This site represents maximum concentrations on an urban scale.

Urban Scale



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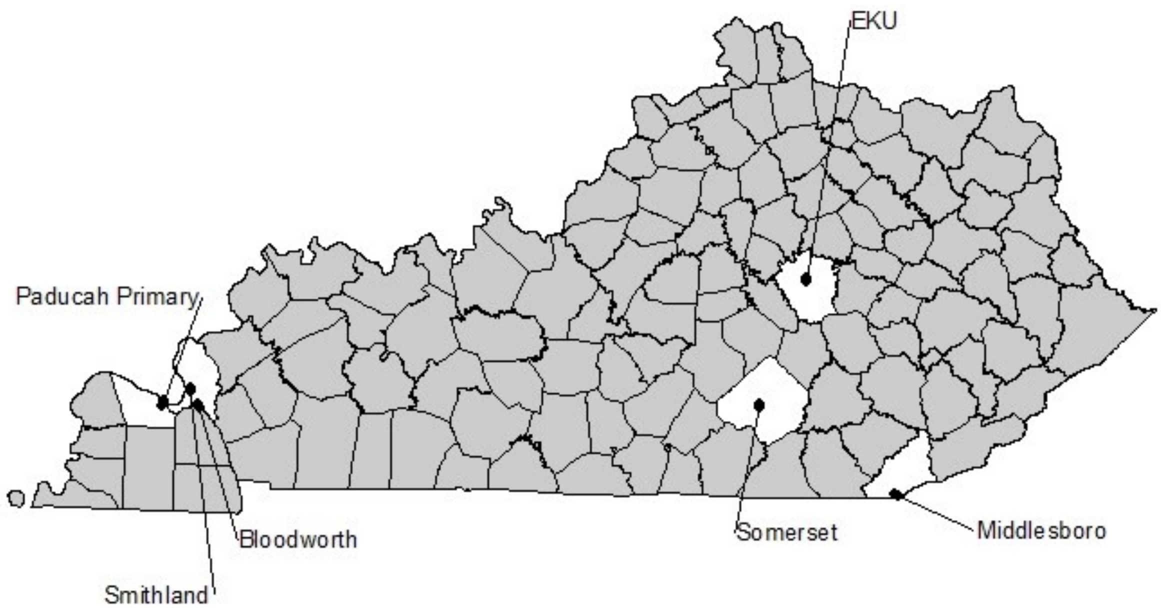
Micropolitan Statistical Areas



AQS ID / County	Site Address	PM2.5	Cont. PM2.5	PM10	Cont. PM10	SO2	NO2	NOy	CO	O3	Pb	VOC	Carbonyl	PAH	PM2.5 Spec.	Carbon Spec.	RadNet	Met
21-013-0002 Bell	1420 Dorchester Ave. Middlesboro	1								1								1
21-139-0003 Livingston	706 State Drive Smithland									1							1	
21-139-0004 Livingston	763 Bloodworth Road Smithland			1^{m}								1						1
21-145-1024 McCracken	2901 Powell Street Paducah	1	1^{Si}	1		1^{Pei}	1^{ei}			1^{ei}								
21-151-0005 Madison	Van Hoose Drive Richmond										2^{C}							
21-199-0003 Pulaski	305 Clifty Street Somerset	1								1								
Totals	**6**	**3**	**1**	**2**		**1**	**1**			**4**	**2**	**1**					**1**	**2**

Tallies are equal to the actual number of monitors present. Superscripts represent additional information about the network.

P= PWEI SO2 monitor required in CBSA.

C =Collocated
P =PWEI Monitor
S =Continuous T640 Monitor
m =PM10 Filter Analyzed for Metals
e =Emergency Episode Monitor
i =AQI Reported

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CSA/MSA: Middlesborough, KY Micropolitan Statistical Area
401 KAR 50:020 Air Quality Region: Appalachian Intrastate (101)
Site Name: Middlesboro
AQS Site ID: 21-013-0002
Location: Middlesboro Airport, 1420 Dorchester Avenue, Middlesboro, KY 40965
County: Bell
GPS Coordinates: 36.60843, -83.73694 (NAD 83)
Date Established: February 14, 1992
Inspection Date: December 5, 2017
Inspection By: Shauna Switzer
Site Approval Status: Site and monitors meet all design criteria for the monitoring network.

The monitoring site is a stationary equipment shelter located on the grounds of the Middlesboro Airport in Middlesboro, Kentucky. The sample inlets are 93.5 meters from the nearest road. Upon inspection the sample lines and monitors were found to be in good condition. The site meets the requirements of 40 CFR 58, Appendices A, C, D, and E.

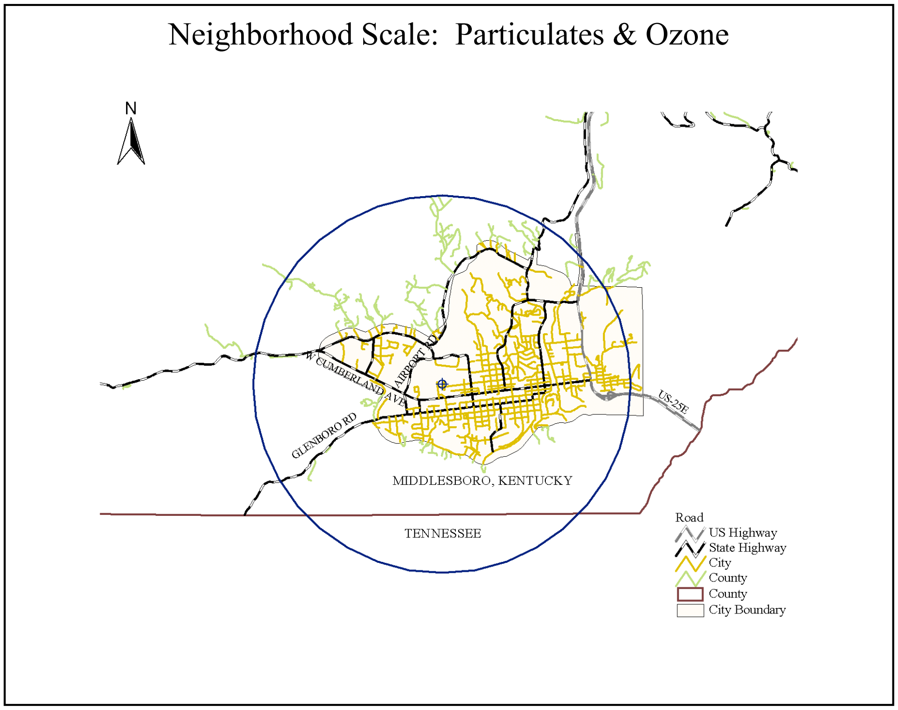
Monitoring Objective:
The monitoring objectives are to determine compliance with National Ambient Air Quality Standards and to provide information on the transport of ozone into the region.

Monitors:

Monitor Type	Inlet Height (meters)	Designation	Analysis Method	Frequency of Sampling
AEM Ozone	3.8	SPM	UV photometry	Continuously March 1 – October 31
FRM $PM_{2.5}$	5.0	SPM	Gravimetric	24-hours every sixth day
Meteorological	5.8	Other	AQM grade instruments for wind speed, wind direction, humidity, barometric pressure and temperature	Continuously

Quality Assurance Status:
All Quality Assurance procedures have been implemented in accordance with 40 CFR 58, Appendix A.

Area Representativeness:
The site represents population exposure on a neighborhood scale for particulates and ozone.



CSA/MSA: Paducah-Mayfield, KY-IL CSA; Paducah, KY-IL Micropolitan Statistical Area
401 KAR 50:020 Air Quality Region: Paducah-Cairo Interstate (072)
Site Name: Smithland
AQS Site ID: 21-139-0003
Location: Livingston County Road Dept., 730 State Drive, Smithland, KY 42081
County: Livingston
GPS Coordinates: 37.155392, -88.394024 (NAD 83)
Date Established: April 1, 1988
Inspection Date: December 19, 2017
Inspection By: Shauna Switzer
Site Approval Status: Site and monitors meet all design criteria for the monitoring network.

The monitoring site is a stationary equipment shelter located on the grounds of the Livingston County Road Dept. facility in Smithland, Kentucky. The sample inlets are 178.9 meters from the nearest road. Upon inspection, the sample lines and monitors were found to be in good condition. The site meets the requirements of 40 CFR 58, Appendices A, C, D, and E.

Monitoring Objective:
The monitoring objective is to determine compliance with National Ambient Air Quality Standards.

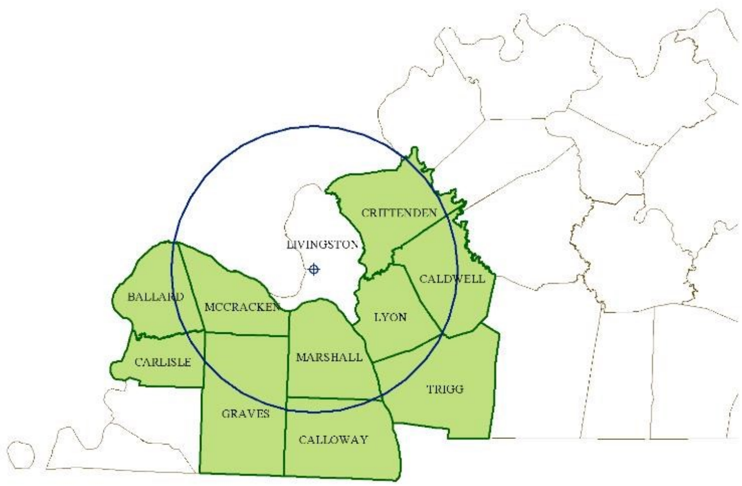
Monitors:

Monitor Type	Inlet Height (meters)	Designation	Analysis Method	Frequency of Sampling
AEM Ozone	3.8	SLAMS	UV photometry	Continuously
Radiation	1.3	RadNet	RadNet fixed stationary monitor, manual and automated methods	Continuously & 2 weekly filters

Quality Assurance Status:
All Quality Assurance procedures have been implemented in accordance with 40 CFR 58, Appendix A.

Area Representativeness:
This site represents maximum concentrations on an urban scale.

Urban Scale



CSA/MSA: Paducah-Mayfield, KY-IL CSA; Paducah, KY-IL Micropolitan Statistical Area
401 KAR 50:020 Air Quality Region: Paducah-Cairo Interstate (072)
Site Name: Bloodworth
AQS Site ID: 21-139-0004
Location: 763 Bloodworth Road, Smithland, KY 42081
County: Livingston
GPS Coordinates: 37.07151, -88.33389 (NAD 83)
Date Established: September 15, 1986
Inspection Date: December 19, 2017
Inspection By: Shauna Switzer
Site Approval Status: Site and monitors meet all design criteria for the monitoring network.

The monitoring site is a stationary equipment shelter located at the residence of 763 Bloodworth Road in Livingston County, Kentucky. The sample inlets are 8 meters from the nearest road, which is an access road for a residence. Upon inspection, the inlet and sampler were found to be in good condition. The site meets the requirements of 40 CFR 58, Appendices A, C, D, and E.

Monitoring Objective:
The monitoring objective is to determine compliance with National Ambient Air Quality Standards for PM_{10} and to detect and quantify air toxics in ambient air.

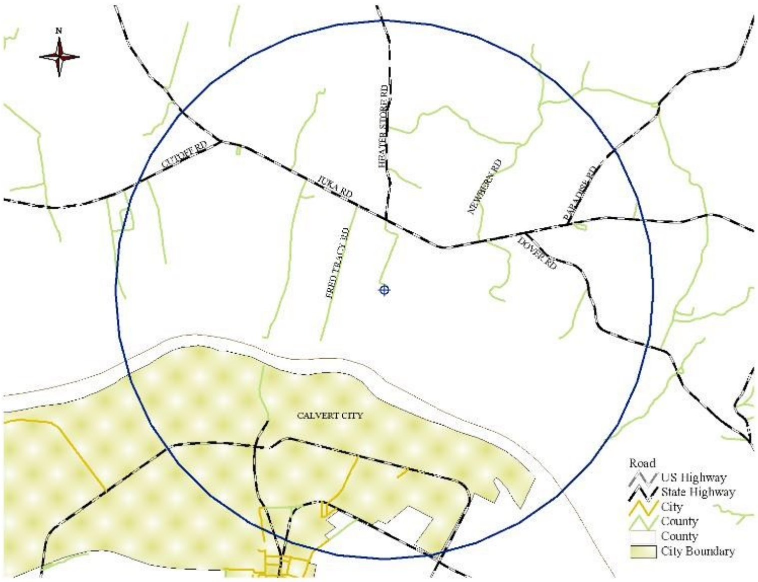
Monitors:

Monitor Type	Inlet Height (meters)	Designation	Analysis Method	Frequency of Sampling
Volatile Organic Compounds	4.3	SPM-Other	EPA method TO-15	24-hours every sixth day
FRM PM_{10}	4.4	SPM	Gravimetric	24-hours every sixth day
- Metals PM_{10}		SPM-Other	Determined from the PM_{10} sample using EPA method IO 3.5	Same as PM_{10}
Meteorological	5.6	Other	AQM grade instruments for wind speed, wind direction, humidity, barometric pressure and temperature	Continuously

Quality Assurance Status:
All Quality Assurance procedures have been implemented in accordance with 40 CFR 58, Appendix A.

Area Representativeness:
The site represents source impacts on a neighborhood scale.

Neighborhood Scale



CSA/MSA: Paducah-Mayfield, KY-IL CSA; Paducah, KY-IL Micropolitan Statistical Area
401 KAR 50:020 Air Quality Region: Paducah-Cairo Interstate (072)
Site Name: Jackson Purchase-Paducah Primary
AQS Site ID: 21-145-1024
Location: Jackson Purchase RECC, 2901 Powell Street, Paducah, KY 42003
County: McCracken
GPS Coordinates: 37.05822, -88.57251 (NAD 83)
Date Established: August 15, 1980
Inspection Date: December 19, 2017
Inspection By: Shauna Switzer
Site Approval Status: Site and monitors meet design criteria for the monitoring network.

The monitoring site is a stationary equipment shelter located on the grounds of the Jackson Purchase RECC in Paducah, Kentucky. While the site meets most of the requirements established by 40 CFR 58, Appendices C, D, E and G, the sample inlets are only 9.1 meters from the nearest road, which is closer than the distances allowed by 40 CFR 58, Appendix E. Due to the small traffic count of the street and the unlikely influence of vehicle-exhaust on data, KDAQ has received EPA-approval for a waiver from the minimum allowable road-distances for all monitors at the site.

Monitoring Objective:
The monitoring objectives are to determine compliance with National Ambient Air Quality Standards and to detect elevated pollutant levels for activation of emergency control procedures for nitrogen dioxide, ozone, and sulfur dioxide. While not required for the CBSA, the site also provides pollutant levels for daily air quality index reporting.

Monitors:

Monitor Type	Inlet Height (meters)	Designation	Analysis Method	Frequency of Sampling
AEM Nitrogen Dioxide (NO_2, NO, NO_x)	3.6	SLAMS EPISODE AQI	Chemiluminescence	Continuously
AEM Sulfur Dioxide	3.6	SLAMS AQI EPISODE	UV fluorescence	Continuously
AEM Ozone	3.6	SLAMS AQI EPISODE	UV photometry	Continuously March 1 – October 31

Monitors (continued):

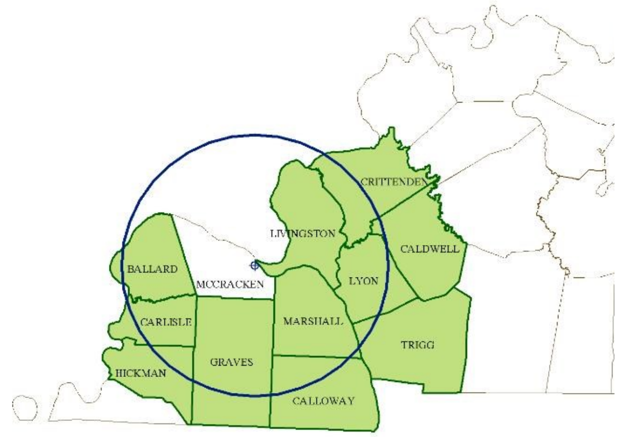
$PM_{2.5}$ Continuous	4.7	SPM AQI	Broadband Spectroscopy	Continuously
FRM $PM_{2.5}$	4.7	SLAMS	Gravimetric	24-hours every third day
FEM PM_{10}	4.5	SLAMS	Gravimetric	24-hours every sixth day

Quality Assurance Status:

Area Representativeness:
This site represents population exposure on a neighborhood scale for ozone, particulates, and sulfur dioxide. This site also represents population exposure on an urban scale for nitrogen dioxide.

Neighborhood Scale: Ozone, Particulates, Sulfur Dioxide

Urban Scale: Nitrogen Dioxide



CSA/MSA: Lexington-Fayette-Richmond-Frankfort KY CSA; Richmond-Berea, KY Micropolitan Statistical Area
401 KAR 50:020 Air Quality Region: Bluegrass Intrastate (102)
Site Name: EKU
AQS Site ID: 21-151-0005
Location: Eastern Kentucky University, Van Hoose Drive, Richmond, KY 40475
County: Madison
GPS Coordinates: 37.73635, -84.29169 (NAD 83)
Date Established: November 17, 2017
Inspection Date: June 30, 2016
Inspection By: Shauna Switzer
Site Approval Status: Site and monitors meet all design criteria for the monitoring network.

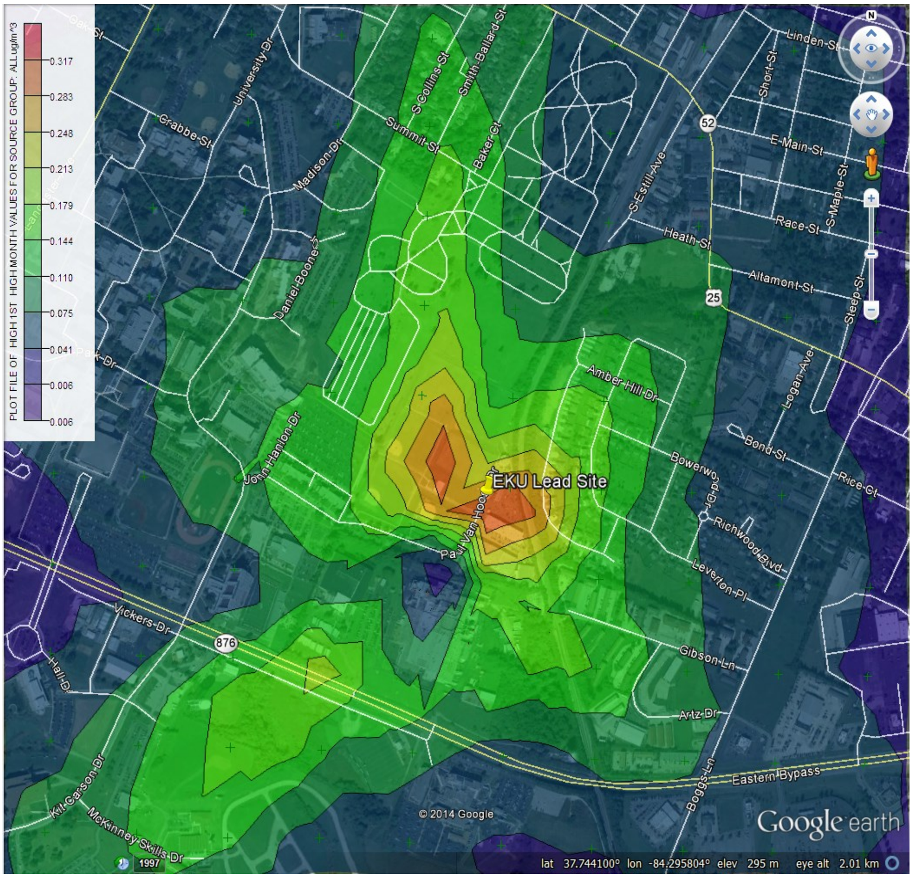
The site is located behind the Gentry Facilities Services building and is adjacent to Eastern Kentucky University's athletic fields. The sample inlets are 2.9 meters from the nearest road. Upon inspection, the sample inlet and monitor were found to be in good condition. The site meets the requirements of 40 CFR 58, Appendices A, C, D and E.

Monitoring Objective:
The monitoring objectives are to determine compliance with National Ambient Air Quality Standards.

Monitors:

Monitor Type	Inlet Height (meters)	Designation	Analysis Method	Frequency of Sampling
FRM Lead	2.2	SLAMS	High volume air sampler. Analysis via ICP-MS.	24-hours every sixth day
Collocated FRM Lead	2.3	SLAMS	High volume air sampler. Analysis via ICP-MS.	24-hours every twelfth day

Quality Assurance Status:
All Quality Assurance procedures have been implemented in accordance with 40 CFR 58, Appendix A.



Area Representativeness:
This site represents source impacts on a micro scale for lead.

Micro Scale: Lead (100 m)

CSA/MSA: Somerset, KY Micropolitan Statistical Area
401 KAR 50:020 Air Quality Control Region: South Central Kentucky Intrastate (105)
Site Name: Somerset
AQS Site ID: 21-199-0003
Location: Somerset Gas Company Warehouse, 305 Clifty Street, Somerset, KY 42501
County: Pulaski
GPS Coordinates: 37.09798, -84.61152 (NAD 83)
Date Established: February 14, 1992
Inspection Date: December 12, 2017
Inspection By: Shauna Switzer
Site Approval Status: Site and monitors meet all design criteria for the monitoring network.

The monitoring site is a stationary equipment shelter located on the grounds of the Somerset Gas Company Warehouse on Clifty Street in Somerset, KY. The sample inlets are 10 meters from the nearest road, which is a dead-end street with little traffic. Upon inspection the sample line and monitors were found to be in good condition. The site meets the requirements of 40 CFR 58, Appendices A, C, D, and E.

Monitoring Objective:
The monitoring objectives are to determine compliance with National Ambient Air Quality Standards.

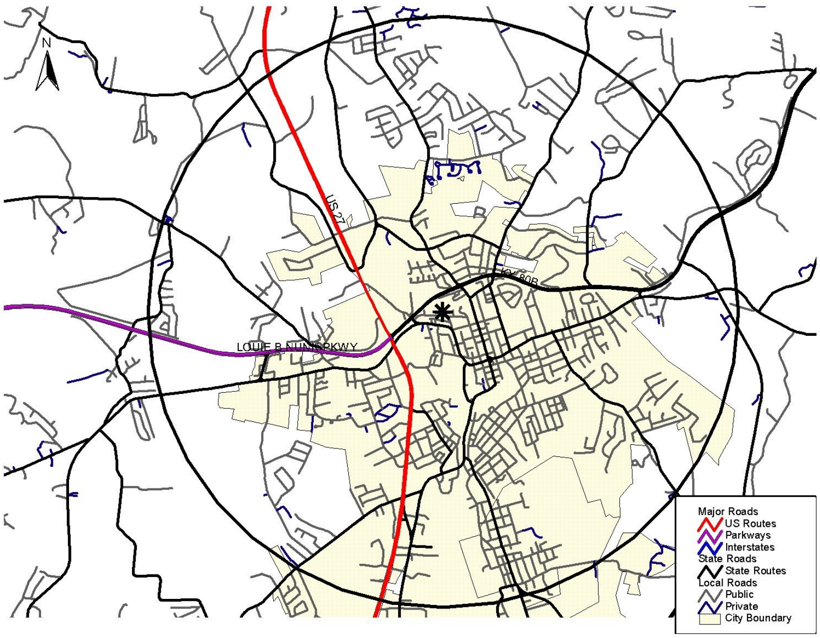
Monitors:

Monitor Type	Inlet Height (meters)	Designation	Analysis Method	Frequency of Sampling
AEM Ozone	4.2	SPM	UV photometry	Continuously March 1 – October 31
FRM $PM_{2.5}$	4.5	SPM	Gravimetric	24-hours every third day

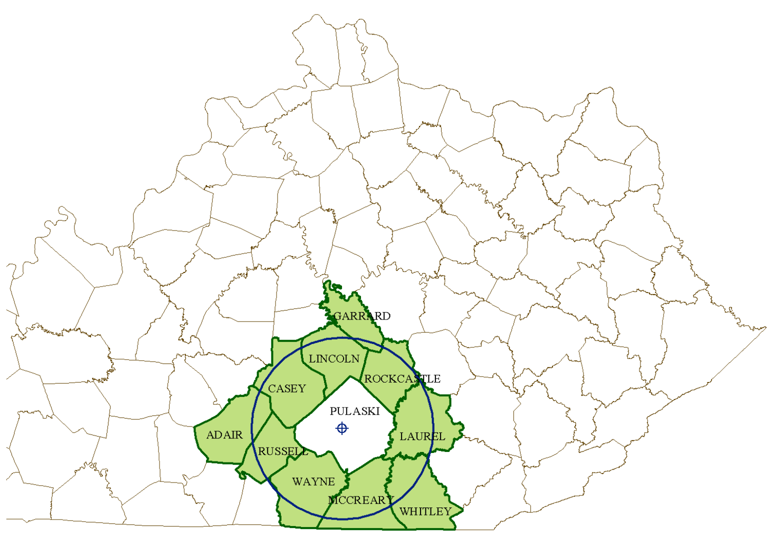
Quality Assurance Status:
All Quality Assurance procedures have been implemented in accordance with 40 CFR 58, Appendix A.

Area Representativeness:
The site represents population exposure on an urban scale for ozone. This site also represents population exposure on a neighborhood scale for particulates.

Neighborhood Scale: Particulates



Urban Scale: Ozone



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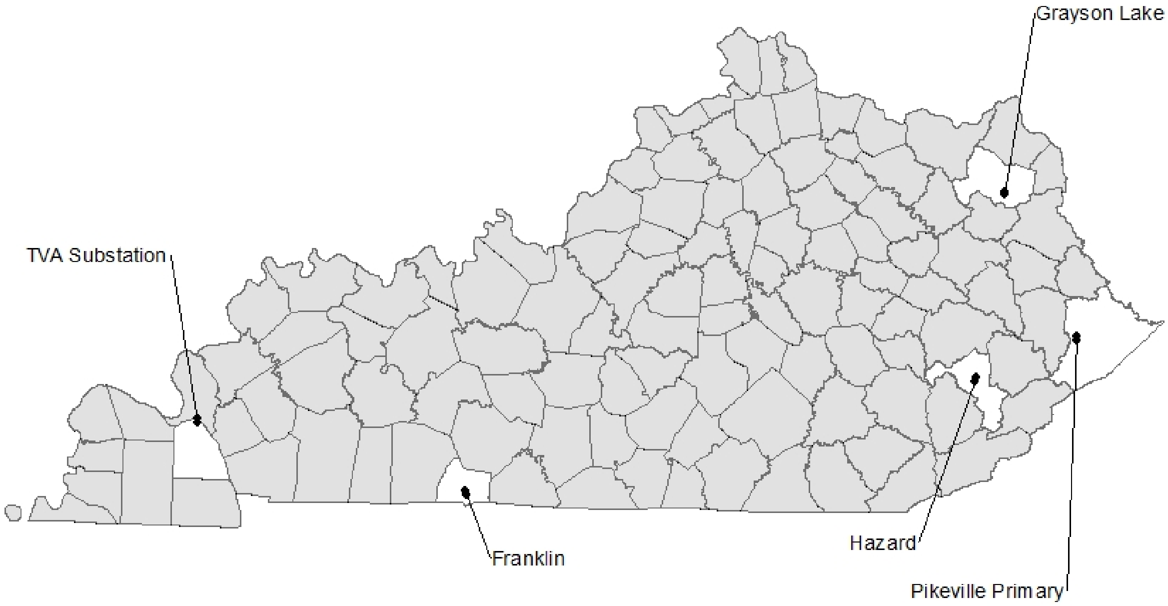
Not in a Metropolitan or Micropolitan Statistical Area



AQS ID / County	Site Address	PM2.5	Cont. PM2.5	PM10	Cont. PM10	SO2	NO2	NOy	CO	O3	Pb	VOC	Carbonyl	PAH	PM2.5 Spec.	Carbon Spec.	RadNet	Met
21-043-0500 Carter	1486 Camp Webb Road Grayson	1^{X}		2^{Cm}						1		2^{D}	2^{D}	1				1
21-157-0014 Marshall	Industrial Parkway Calvert City											2^{C}						
21-193-0003 Perry	354 Perry Park Road Hazard	1	1^{t}							1^{e}								1
21-195-0002 Pike	109 Loraine Street Pikeville	1	$1^{S,i}$							1^{i}								
21-213-0004 Simpson	573 Harding Road Franklin									1								1
Totals	**5**	**3**	**2**	**2**						**4**		**4**	**2**	**1**				**3**

Tallies are equal to the actual number of monitors present. Superscripts represent additional information about the network.

D =Duplicate
C =Collocated
t =Continuous TEOM Monitor
S =Continuous PM T640
m =PM10 Filter Analyzed for Metals
i =AQI Reported
X =Regional Background PM2.5 Monitor

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CSA/MSA: Not in a MSA - Rural
401 KAR 50:020 Air Quality Region: Huntington (WV)-Ashland (KY)-Portsmouth-Ironton (OH) Interstate (103)
Site Name: Grayson Lake
AQS Site ID: 21-043-0500
Location: Camp Robert Webb, 1486 Camp Webb Road, Grayson Lake, KY 41143
County: Carter
GPS Coordinates: 38.23887, -82.98810 (NAD 83)
Date Established: May 13, 1983
Inspection Date: December 4, 2017
Inspection By: Shauna Switzer
Site Approval Status: Site and monitors meet all design criteria for the monitoring network.

The monitoring site is a stationary equipment shelter in a fenced area located in a remote section of Camp Webb in Grayson, Kentucky. The nearest road is a service road to the site and is 108 meters from the site. Upon inspection, the sample lines and monitors were found to be in good condition. The site meets the requirements of 40 CFR 58, Appendices A, C, D, and E.

Monitoring Objective:
The monitoring objectives are to determine compliance with National Ambient Air Quality Standards; to determine background levels of $PM_{2.5}$ and PM_{10}; to provide ozone data upwind of the Ashland area; and to measure rural concentrations of a sub-group of air toxics for use in a national air toxics assessment.

Monitors:

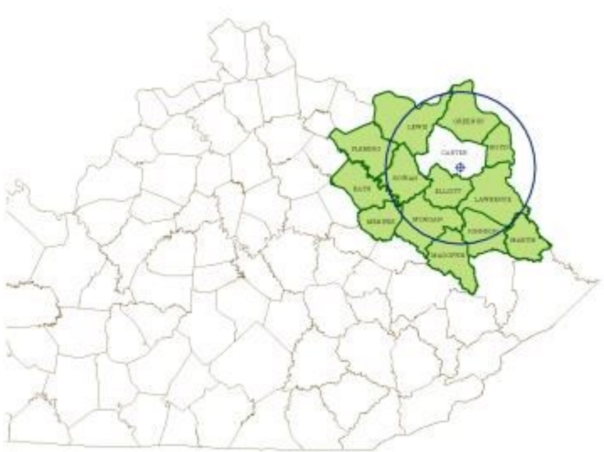
Monitor Type	Inlet Height (meters)	Designation	Analysis Method	Frequency of Sampling
AEM Ozone	3.7	SPM	UV photometry	Continuously March 1 – October 31
FRM PM_{10}	2.1	SLAMS	Gravimetric	24-hours every sixth day
- Metals PM_{10}		NATTS SPM-Other	Determined from the PM_{10} samples using EPA method IO 3.5	Same as PM_{10}
Collocated PM_{10}	2.1	SLAMS	Gravimetric	24-hours every twelfth day
- Collocated metals PM_{10}		NATTS SPM-Other	Determined from the PM_{10} samples using EPA method IO 3.5	24-hours; six samples per year

FRM $PM_{2.5}$	2.3	SLAMS	Gravimetric	24-hours every third day
Volatile Organic Compounds	3.7	NATTS SPM-Other	EPA method TO-15.	24-hours every sixth day
- Duplicate Volatile Organic Compounds		NATTS SPM-Other	EPA method TO-15. Collected via same sampling system as primary VOCs.	24-hours; six samples per year
Polycyclic Aromatic Hydrocarbons	2.1	NATTS SPM-Other	EPA method TO-13A	24-hours every sixth day
Carbonyls	4.0	NATTS SPM-Other	EPA method TO-11A	24-hours every sixth day
- Duplicate Carbonyls		NATTS SPM-Other	EPA method TO-11A. Collected via same sampling system as primary carbonyls.	24-hours; six samples per year
Meteorological	11.75	Other	AQM grade instruments for wind speed, wind direction, relative humidity, and temperature	Continuously

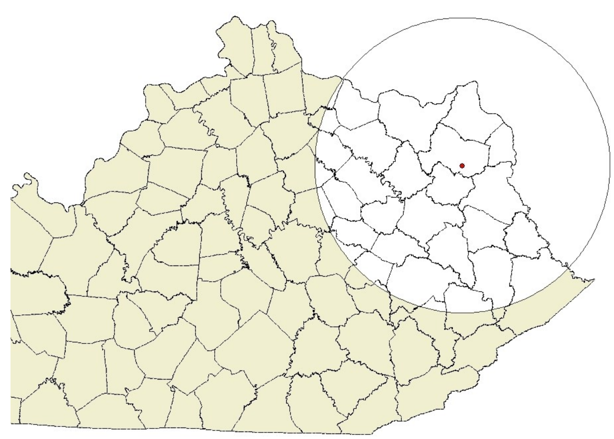
Quality Assurance Status:
All Quality Assurance procedures have been implemented in accordance with 40 CFR 58, Appendix A.

Area Representativeness:
The site represents background levels on an urban scale for particulates and air toxics. This site also represents upwind/background levels on an regional scale for ozone.

Urban Scale: Particulates & Air Toxics



Regional Scale: Ozone



CSA/MSA: Not in a MSA - Rural
401 KAR 50:020 Air Quality Control Region: Paducah – Cairo Interstate (072)
Site Name: TVA Substation
AQS Site ID: 21-157-0014
Location: Plant Cutoff Road & Industrial Parkway, Calvert City, KY 42029
County: Marshall
GPS Coordinates: 37.04520, -88.33087 (NAD 83)
Date Established: January 1, 2005
Inspection Date: December 19, 2017
Inspection By: Shauna Switzer
Site Approval Status: Site and monitors meet all design criteria for the monitoring network.

The monitoring site is located off Ballpark Road in Calvert City, Kentucky. The inlets are approximately 231.6 meters from the nearest road. Upon inspection, the sample inlets and monitors were found to be in good condition.

Due to expansion of the fenced-compound of the TVA electrical substation, the samplers were relocated in June 2013. The new location is approximately 20 meters northwest from the original location and is still along the fence-line of the compound.

Monitoring Objective:
The monitoring objectives are to detect and quantify air toxic pollutants.

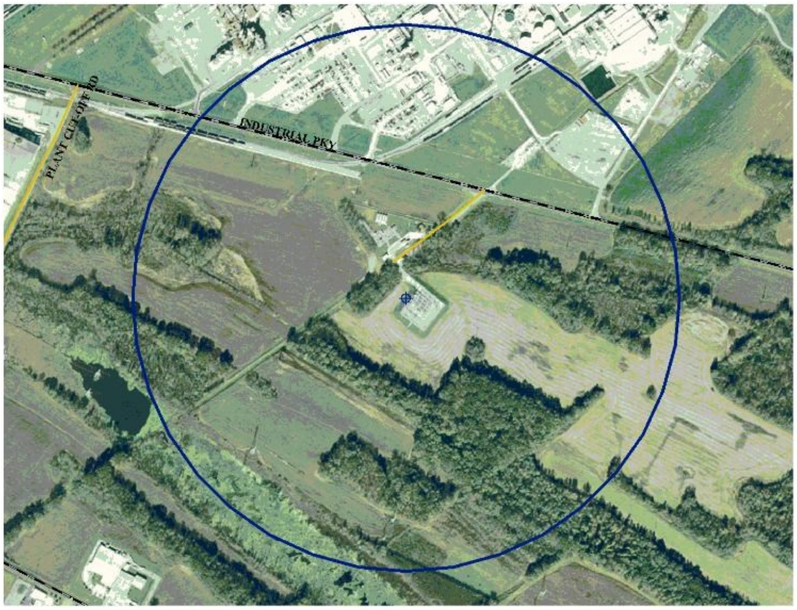
Monitors:

Monitor Type	Inlet Height (meters)	Designation	Analysis Method	Frequency of Sampling
Volatile Organic Compounds	2.0	SPM-Other	EPA method TO-15	24-hours every sixth day
Collocated Volatile Organic Compounds	1.9	SPM-Other	EPA method TO-15	24-hours every twelfth day

Quality Assurance Status:
All Quality Assurance procedures have been implemented in accordance with 40 CFR 58, Appendix A.

Area Representativeness:
This site represents source oriented exposure on a middle scale.

Middle Scale



CSA/MSA: Not in a MSA - Rural
401 KAR 50:020 Air Quality Control Region: Appalachian Intrastate (101)
Site Name: Hazard
AQS Site ID: 21-193-0003
Location: Perry County Horse Park, 354 Perry Park Road, Hazard, KY 41701
County: Perry
GPS Coordinates: 37.28329, -83.20932 (NAD 83)
Date Established: April 1, 2000
Inspection Date: December 5, 2017
Inspection By: Shauna Switzer
Site Approval Status: Site and monitors meet all design criteria for the monitoring network.

The monitoring site is a stationary equipment shelter located on the grounds of the Perry County Horse Park in Hazard, Kentucky. The sample inlets 29.2 meters from the nearest road. Upon inspection the sample lines and monitors were found to be in good condition. This site meets the requirements of 40 CFR 58, Appendices A, C, D, and E.

Monitoring Objective:
The monitoring objectives are to determine compliance with National Ambient Air Quality Standards and to detect elevated pollutant levels for activation of emergency control procedures for ozone.

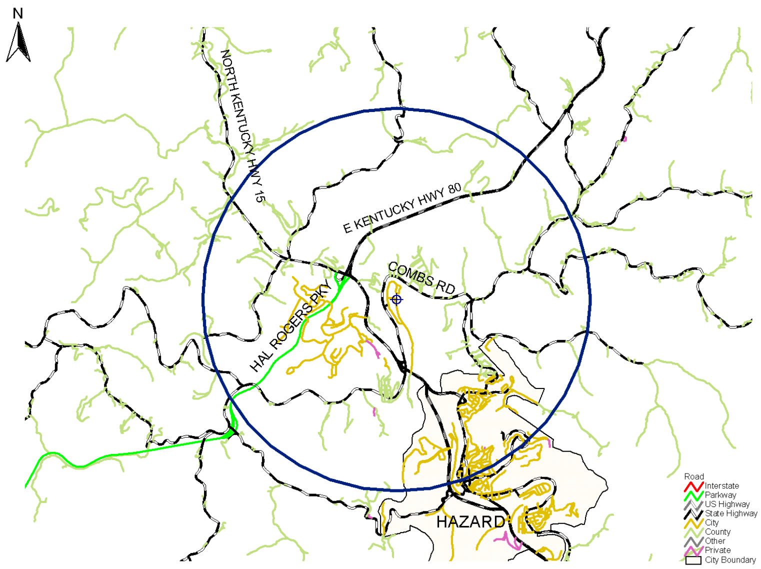
Monitors:

Monitor Type	Inlet Height (meters)	Designation	Analysis Method	Frequency of Sampling
AEM Ozone	3.7	SPM EPISODE	UV photometry	Continuously March 1 – October 31
FRM $PM_{2.5}$	2.3	SPM	Gravimetric	24-hours every sixth day
$PM_{2.5}$ TEOM	4.6	SPM	Tapered element oscillating microbalance, gravimetric	Continuously
Meteorological	5.6	Other	AQM grade instruments for wind speed, wind direction, relative humidity, barometric pressure, and temperature	Continuously

Quality Assurance Status:
All Quality Assurance procedures have been implemented in accordance with 40 CFR 58, Appendix A.

Area Representativeness:
The site represents population exposure on a neighborhood scale.

Neighborhood Scale



CSA/MSA: Not in a MSA - Rural
401 KAR 50:020 Air Quality Control Region: Appalachian Intrastate (101)
Site Name: Pikeville Primary
AQS Site ID: 21-195-0002
Location: KYTC District Office, 109 Loraine Street, Pikeville, KY 41501
County: Pike
GPS Coordinates: 37.48260, -82.53532 (NAD 83)
Date Established: May 1, 1994
Inspection Date: December 5, 2017
Inspection By: Shauna Switzer
Site Approval Status: Site and monitors meet all design criteria for the monitoring network.

The monitoring site is a stationary equipment shelter located behind the KYTC District Office building in Pikeville, KY. The sample inlets are 91.1 meters from the nearest road. Upon inspection the sample lines and monitors were found to be in good condition. This site meets the requirements of 40 CFR 58, Appendices A, C, D, E and G.

Monitoring Objective:
The monitoring objectives are to determine compliance with National Ambient Air Quality Standards. While not required, the site also provides pollutant levels for daily air quality index reporting.

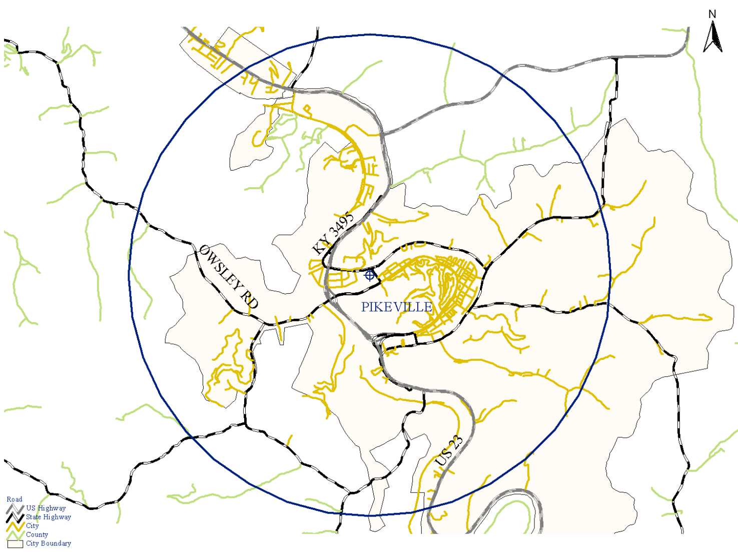
Monitors:

Monitor Type	Inlet Height (meters)	Designation	Analysis Method	Frequency of Sampling
AEM Ozone	3.6	SPM AQI	UV photometry	Continuously March 1 – October 31
FRM $PM_{2.5}$	4.6	SLAMS	Gravimetric	24-hours every third day
$PM_{2.5}$ Continuous	TBD (Install date 1/31/18)	SPM AQI	Broadband Spectroscopy	Continuously

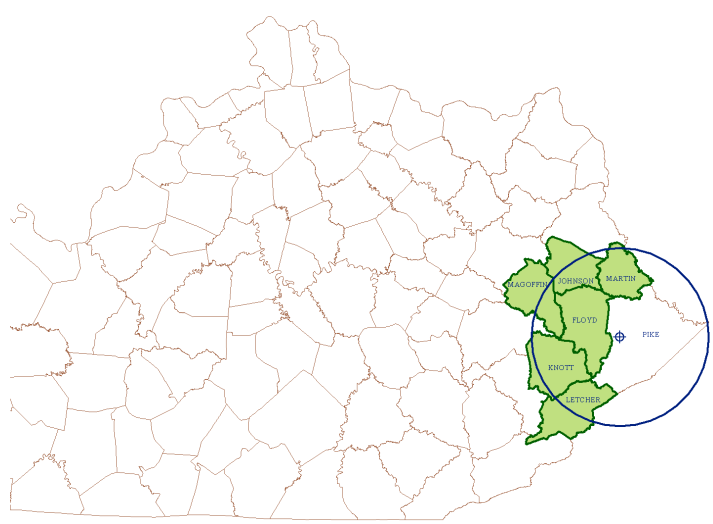
Quality Assurance Status:
All Quality Assurance procedures have been implemented in accordance with 40 CFR 58, Appendix A.

Area Representativeness:
The site represents population exposure on a neighborhood scale for particulates. This site also represents population exposure on an urban scale for ozone.

Neighborhood Scale: Particulates



Urban Scale: Ozone



CSA/MSA: Not in a MSA - Rural
401 KAR 50:020 Air Quality Control Region: South Central Kentucky Intrastate (105)
Site Name: Franklin
AQS Site ID: 21-213-0004
Location: KYTC Maintenance Facility, 573 Harding Road (KY1008), Franklin, KY 42134
County: Simpson
GPS Coordinates: 36.708607, -86.566284 (NAD 83)
Date Established: June 19, 1991
Inspection Date: December 15, 2017
Inspection By: James Plunkett
Site Approval Status: Site and monitors meet all design criteria for the monitoring network.

The monitoring site is a stationary equipment shelter located on the grounds of the KYTC Garage on Harding Road (KY1008) in Franklin, Kentucky. The sample inlet is 41.5 meters from the nearest road. Upon inspection, the sample line and monitor were found to be in good condition. The site meets the requirements of 40 CFR 58, Appendices A, C, D, and E.

Monitoring Objective:
The monitoring objectives are to determine compliance with National Ambient Air Quality Standards; to measure ozone levels upwind of Bowling Green; and to provide data on interstate ozone transport.

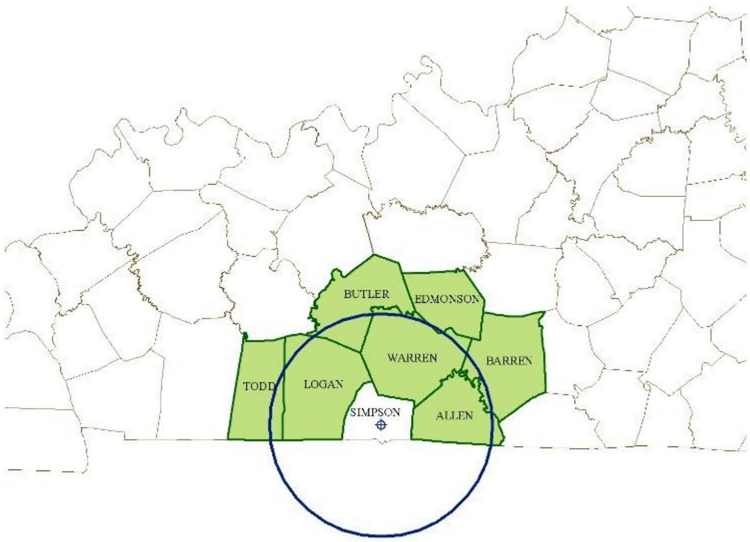
Monitors:

Monitor Type	Inlet Height (meters)	Designation	Analysis Method	Frequency of Sampling
AEM Ozone	4.4	SPM	UV photometry	Continuously March 1 – October 31
Meteorological	5.8	Other	AQM grade instruments for wind speed, wind direction, relative humidity, barometric pressure, and temperature	Continuously

Quality Assurance Status:
All Quality Assurance procedures have been implemented in accordance with 40 CFR 58, Appendix A.

Area Representativeness:
The site represents population exposure on an urban scale.

Urban Scale



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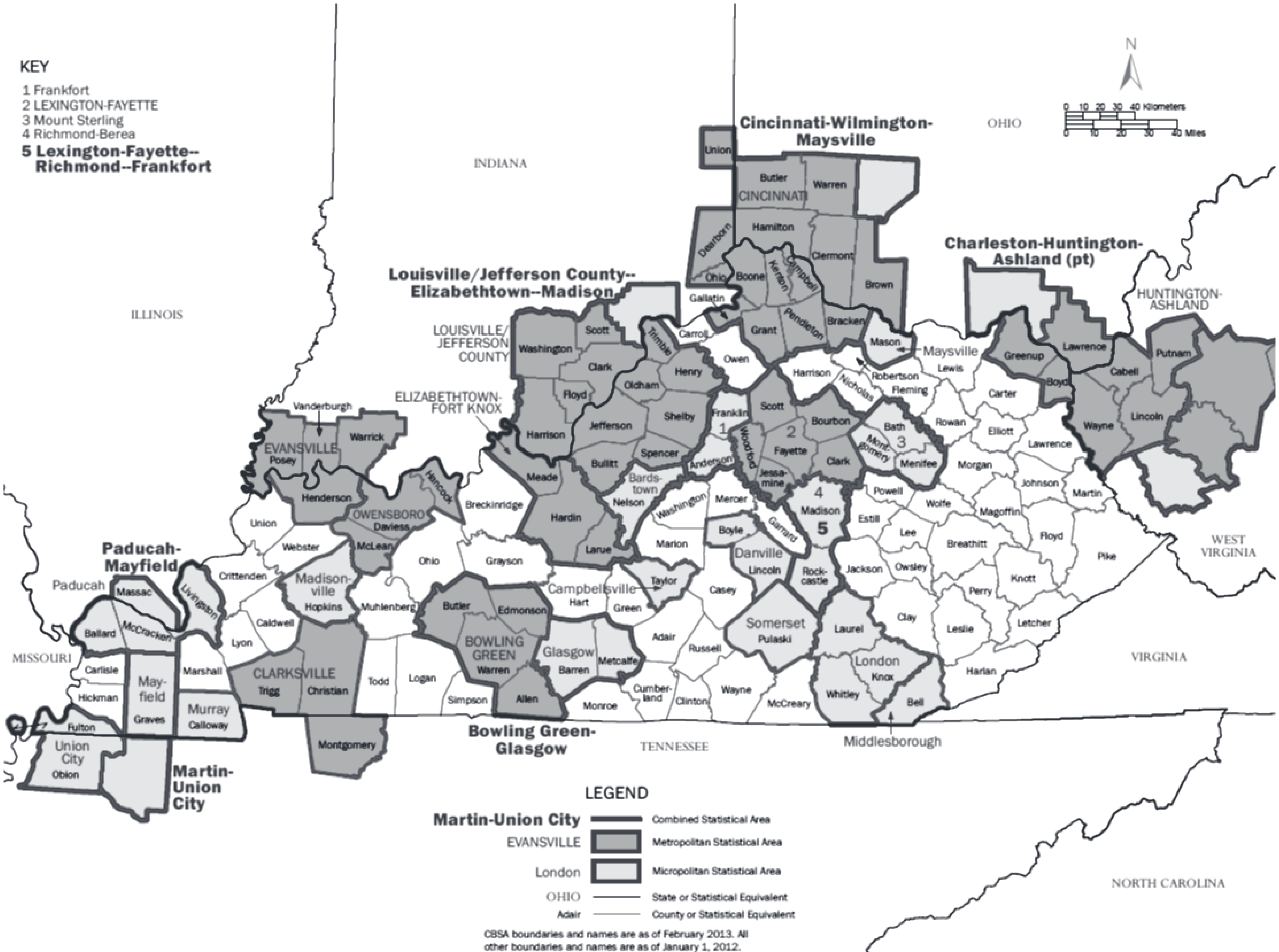
APPENDIX A

KENTUCKY CORE-BASED STATISTICAL AREAS AND COUNTIES MAP

Kentucky - Core Based Statistical Areas (CBSAs) and Counties



APPENDIX B

MEMORANDUM OF AGREEMENT
CINCINNATI, OH-KY-IN MSA

MEMORANDUM OF AGREEMENT
ON AIR QUALITY MONITORING FOR CRITERIA POLLUTANTS FOR
THE CINCINNATI OH-KY-IN
METROPOLITAN STATISTICAL AREA (MSA)

Participating Agencies:

Kentucky Department for Environmental Protection (KDEP)
Division for Air Quality (DAQ)

Hamilton County Department of Environmental Services (HCDOES)

Indiana Department of Environmental Management (IDEM)
Office of Air Quality (OAQ)

PURPOSE/OBJECTIVES/GOALS

The purpose of this Memorandum of Agreement (MOA) is to establish the Cincinnati OH-KY-IN Metropolitan Statistical Area (MSA) Criteria Pollutant Air Quality Monitoring Agreement among KDEP, IDEM, and HCDOES to collectively meet United States Environmental Protection Agency (EPA) minimum monitoring requirements for particles of an aerodynamic diameter of 10 micrometers and less (PM10), particles of an aerodynamic diameter of 2.5 micrometers and less (PM2.5), and ozone; as well as other criteria pollutant air quality monitoring deemed necessary to meet the needs of the MSA as determined reasonable by all parties. According to 40 CFR Part 58, Appendix D, the Cincinnati OH-KY-IN MSA minimum monitoring requirements (based on a population of 2,172,000) are (2) ozone monitors, (2-4) PM-10 monitors, (3) FRM PM-2.5 monitors, and (2) collocated continuous PM-2.5 monitors with the FRM PM-2.5 monitors. This MOA will formalize and reaffirm the collective agreement in order to provide adequate criteria pollutant monitoring for the Cincinnati OH-KY-IN MSA as required by 40 CFR 58 Appendix D, Section 2(e).

PM2.5 MSA monitoring network includes:

County	Federal Reference Method PM2.5	Continuous PM2.5	Speciation PM2.5	Collocated PM2.5
Campbell County, KY KDEP	1	1	0	0
Boone County, KY KDEP	0	0	0	0
Hamilton County, OH **HCDOES**	4	2	1	1
Butler County, OH **HCDOES**	2	0	0	1
Clermont County, OH **HCDOES**	1	1	0	0
Warren County, OH **HCDOES**	1	1	0	0
Franklin County, IN **IDEM**	0	0	0	0
Dearborn County, IN **IDEM**	0	0	0	0
Ohio County, IN **IDEM**	0	0	0	0

Criteria Air Pollutant MSA monitoring network includes:

County	PM10	O_3	NO_x/NO/NO2	CO	SO_2
Campbell County, KY **KDEP**	0	1	1	0	1
Boone County, KY **KDEP**	0	1	0	0	0
Hamilton County, OH **HCDOES**	3	3	1	1	1
Butler County, OH **HCDOES**	2	2	0	0	0
Clermont County, OH **HCDOES**	0	1	0	0	0
Warren County, OH **HCDOES**	0	1	0	0	0
Franklin County, IN **IDEM**	0	0	0	0	0
Dearborn County, IN **IDEM**	0	0	0	0	0
Ohio County, IN **IDEM**	0	0	0	0	0

RESPONSIBLITIES/ACTIONS

Each of the parties to this Agreement is responsible for ensuring that its obligations under the MOA are met. As conditions warrant, the affected agencies may conduct telephone conference calls, meetings, or other communications to discuss monitoring activities for the MSA. Each affected agency shall inform the other affected agencies via telephone or email of any monitoring changes occurring within its jurisdiction of the MSA at its earliest convenience, after learning of the need for the change or making the changes. Such unforeseen changes may include evictions from monitoring sites, destruction of monitoring sites due to natural disasters, or any occurrences that result in an extended (greater than one quarter) or permanent change in the monitoring network.

LIMITATIONS

- All commitments made in this MOA are subject to the availability of appropriated funds and each agency's budget priorities. Nothing in this MOA obligates KDEP, IDEM, or HCDOES to expend appropriations or to enter into any contract, assistance agreement, interagency agreement or other financial obligation.

- This MOA is neither a fiscal nor a funds obligation document. Any endeavor involving reimbursement or contribution of funds between parties to this agreement will be handled in accordance with applicable laws, regulations, and procedures, and will be subject to separate agreements that will be affected in writing by representatives of the parties.

- This MOA does not create any right or benefit enforceable by law or equity against KDEP, IDEM, or HCDOES, their officers or employees, or any other person. This MOA does not apply to any entity outside KDEP, IDEM, or HCDOES.

- No proprietary information or intellectual property is anticipated to arise out of this MOA.

TERMINATION

This Memorandum of Agreement may be revised upon the mutual consent of KDEP, IDEM, and HCDOES. Each party reserves the right to terminate this MOA. A thirty (30) day written notice must be given prior to the date of termination.

APPROVALS

We agree with the provisions outlined in this Memorandum of Agreement and commit our agencies to implement them in a spirit of cooperation and mutual support.

Kentucky Department for Environmental Protection
Division for Air Quality

BY: John Lyons John S. Lyons

TITLE: Director, Division for Air Quality

DATE: 5/13/10

Hamilton County Department of Environmental Services

BY: Cory Chadwick Cory R. Chadwick

TITLE: Director

DATE: 5/13/10

Indiana Department of Environmental Management
Office of Air Quality

BY: Keith Baugues Keith Baugues

TITLE: Assistant Commissioner, Office of Air Quality

DATE: 5/14/10

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APPENDIX C

MEMORANDUM OF AGREEMENT
EVANSVILLE, IN-KY MSA

MEMORANDUM OF AGREEMENT
ON AIR QUALITY MONITORING FOR CRITERIA POLLUTANTS FOR
THE EVANSVILLE, IN-HENDERSON, KY
METROPOLITAN STATISTICAL AREA (MSA)

Participating Agencies:

Kentucky Department for Environmental Protection (KDEP)
Division for Air Quality (DAQ)

Indiana Department of Environmental Management (IDEM)
Office of Air Quality (OAQ)

PURPOSE/OBJECTIVES/GOALS

The purpose of this Memorandum of Agreement (MOA) is to establish the Evansville, IN-Henderson, KY Metropolitan Statistical Area (MSA) Criteria Pollutant Air Quality Monitoring Agreement among KDEP and IDEM to collectively meet United States Environmental Protection Agency (EPA) minimum monitoring requirements for particles of an aerodynamic diameter of 10 micrometers and less (PM 10), particles of an aerodynamic diameter of 2.5 micrometers and less (PM2.5), and ozone; as well as other criteria pollutant air quality monitoring deemed necessary to meet the needs of the MSA as determined reasonable by all parties. According to 40 CFR Part 58, Appendix D, the Evansville, IN-Henderson, KY MSA minimum monitoring requirements (based on a population of 350,000) are (2) ozone monitors, (0-1) PM-10 monitors, (1) FRM PM-2.5 monitor, and (1) collocated continuous PM-2.5 monitor with the FRM pm-2.5 monitor. This MOA will formalize and reaffirm the collective agreement in order to provide adequate criteria pollutant monitoring for the Evansville, IN-Henderson, KY MSA as required by 40 CFR 58 Appendix D, Section 2, (e).

PM 2.5 MSA monitoring network includes:

County	Federal Reference Method PM2.5	Continuous PM2.5	Speciation PM2.5	Collocated PM2.5
Henderson County, KY **KDEP**	1	1	0	0
Vanderburgh County, IN **IDEM**	3	1	1	1

Criteria Air Pollutant MSA monitoring network includes:

County	PM10	O_3	NO_x/NO/NO2	CO	SO_2
Henderson County, KY **KDEP**	1	1	0	0	1
Vanderburgh County, IN **IDEM**	1	2	1	1	1

RESPONSIBLITIES/ACTIONS

Each of the parties to this Agreement is responsible for ensuring that its obligations under the MOA are met. As conditions warrant, the affected agencies may conduct telephone conference calls, meetings, or other communications to discuss monitoring activities for the MSA. Each affected agency shall inform the other affected agencies via telephone or email of any monitoring changes occurring within its jurisdiction of the MSA at its earliest convenience, after learning of the need for the change or making the changes. Such unforeseen changes may include evictions from monitoring sites, destruction of monitoring sites due to natural disasters, or any occurrences that result in an extended (greater than one quarter) or permanent change in the monitoring network.

LIMITATIONS

- All commitments made in this MOA are subject to the availability of appropriated funds and each agency's budget priorities. Nothing in this MOA obligates KDEP or IODEM to expend appropriations or to enter into any contract, assistance agreement, interagency agreement or other financial obligation.
- This MOA is neither a fiscal nor a funds obligation document. Any endeavor involving reimbursement or contribution of funds between parties to this agreement will be handled in accordance with applicable laws, regulations, and procedures, and will be subject to separate agreements that will be affected in writing by representatives of the parties.
- This MOA does not create any right or benefit enforceable by law or equity against KDEP or IDEM, their officers or employees, or any other person. This MOA does not apply to any entity outside KDEP or IDEM.
- No proprietary information or intellectual property is anticipated to arise out of this MOA.

TERMINATION

This Memorandum of Agreement may be revised upon the mutual consent of KDEP and IDEM. Each party reserves the right to terminate this MOA. A thirty (30) day written notice must be given prior to the date of termination.

APPROVALS

We agree with the provisions outlined in this Memorandum of Agreement and commit our agencies to implement them in a spirit of cooperation and mutual support.

Kentucky Department for Environmental Protection
Division for Air Quality

BY: John. S. Lyons

TITLE: Director, Division for Air Quality

DATE: 5/14/10

Indiana Department of Environmental Management
Office of Air Quality

BY: Keith Baugues Keith Baugues

TITLE: Assistant Commissioner, Office of Air Quality

DATE: 5/24/10

APPENDIX D

MEMORANDA OF AGREEMENT
CLARKSVILLE, TN-KY MSA

RECEIVED

JUL 15 2014

DIRECTOR'S OFFICE
DIVISION FOR AIR QUALITY

STATE OF TENNESSEE
DEPARTMENT OF ENVIRONMENT AND CONSERVATION

Division of Air Pollution Control
William R. Snodgrass TN Tower
312 Rosa L. Parks Ave., 15th Floor
Nashville, Tennessee 37243

July 1, 2014

Sean Alteri, Director
Kentucky Division for Air Quality
Kentucky Department for Environmental Protection
200 Fair Oaks Lane
Frankfort, KY 40601

Dear Mr. Alteri:

The United States Environmental Protection Agency (EPA) revised monitoring regulations found in 40 CFR Part 58, Appendix D states in part: "The EPA recognizes that there may be situations where the EPA Regional Administrator and the affected State or local agencies may need to augment or to divide the overall MSA/CSA monitoring responsibilities and requirements among these various agencies to achieve an effective network design. Full monitoring requirements apply separately to each affected State or local agency in the absence of an agreement between the affected agencies and the EPA Regional Administrator." This revision of the CFR also describes the minimum monitoring requirements for the NAAQS pollutants, including continuous PM 2.5 as it applies to MSA areas where the population is sufficient to warrant monitoring for that pollutant. Tennessee and Kentucky share the Clarksville, TN-KY MSA, which is comprised of Trigg and Christian counties in Kentucky and Montgomery county in Tennessee. The US Census Bureau lists this area as containing a population in excess of 260,000.

CBSA Code	Geographic area	Legal/statistical Area description	July 1, 2013 Estimate	2010 Census
17300	Clarksville, TN-KY	Metropolitan Statistical Area	272,579	260,625

The Tennessee Division of Air Pollution Control (TDAPC) currently operates one (1) PM 2.5 FRM monitor and one (1) continuous PM 2.5 monitor in this area. The TDAPC believes the operation of the existing PM 2.5 monitors; (FRM and continuous), are sufficient to properly characterize the particulate air quality in the entire Clarksville, TN-KY MSA and comply with the requirements for both population and concentration based monitoring identified in the revised monitoring regulations as found at 40 CFR58,AppD. The TDAPC would like to invite the

Kentucky Division for Air Quality to participate in Tennessee's annual ambient air monitoring network review. Tennessee commits to sharing with Kentucky any and all quality assured ambient air monitoring data collected in the Tennessee portion of the Clarksville, TN-KY MSA. Tennessee also will notify Kentucky in advance of the intent to relocate or shutdown any of the PM 2.5 monitors referenced above so that adequate monitoring arrangements can be made to meet the entire MSA monitoring requirements for PM 2.5.

Sincerely,

Barry R. Stephens

Barry R. Stephens, PE
Director, Air Pollution Control Division

BRS/lb
Cc: Heather McTeer-Toney, US EPA Region IV

Steven L. Beshear
Governor

Leonard K. Peters
Secretary

Energy and Environment Cabinet
Department for Environmental Protection
Division for Air Quality
200 Fair Oaks Lane, 1st Floor
Frankfort, Kentucky 40601-1403
Web site: air.ky.gov

May 15, 2015

Mr. Barry R. Stephens, PE
Director
Tennessee Division of Air Pollution Control
312 Rosa L. Parks Avenue, 15th Floor
Nashville, TN 37243

Dear Mr. Stephens:

In a letter from your office dated July 1, 2014, the Tennessee Division of Air Pollution Control (TDAPC) agreed to operate a continuous $PM_{2.5}$ monitor and an intermittent FRM $PM_{2.5}$ sampler, to meet the minimum network design requirements stated in 40 CFR 58, Appendix D for the Clarksville, TN-KY metropolitan statistical area (MSA). The Kentucky Division for Air Quality (Division) appreciates TDAPC's cooperation and looks forward to participating in TDAPC's annual air monitoring network review.

The Division currently operates one (1) intermittent FRM $PM_{2.5}$ sampler and one (1) continuous ozone monitor at the Hopkinsville site (21-047-0006) in Christian County. In accordance with Table D-2 of 40 CFR 58, Appendix D, one (1) ozone monitor is required to be operated in the Clarksville, TN-KY MSA, based upon the most current population estimates from the US Census Bureau, as well as 2012-2014 ozone design values.

Geographic Area	Area Description	2014 USCB Population Estimate	2014 Three-Year Ozone DV (ppm)
Christian County, KY	County	74,250	0.067
Trigg County, KY	County	14,142	0.069 (CASTNET)
Montgomery County, TN	County	189,961	N/A
Clarksville, TN-KY	**MSA**	**278,353**	**0.069**

To satisfy the regulatory requirement, the Division agrees to operate one ozone monitor at the Hopkinsville site. Also, the Division agrees to notify TDAPC in the event that shutdown or relocation of the ozone monitor is necessary.

Despite the fact that 2012-2014 design values show that no FRM $PM_{2.5}$ samplers are required in the Clarksville MSA, the Division will continue to operate the $PM_{2.5}$ sampler at

Hopkinsville. The Division also agrees to notify TDAPC in the event that the Hopkinsville FRM $PM_{2.5}$ sampler must be shutdown or relocated, as it is the design value monitor for the MSA.

The Division commits to sharing with TDAPC any and all quality-assured ambient monitoring data collected in the Kentucky portion of the Clarksville, TN-KY MSA. The Division also welcomes TDAPC participation in Kentucky's annual network review process. If you have any questions or concerns, please contact me at 502-564-3999.

Sincerely,

Sean Alteri

Sean Alteri,
Director

SA/jfm
c: -Heather McTeer Toney, USEPA Region IV
-Daniel Garver, USEPA Region IV

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APPENDIX E

LMAPCD
AMBIENT AIR MONITORING
NETWORK 2018

Appendix E - Part A
LMAPCD Proposed Network Changes

AIR POLLUTION CONTROL DISTRICT

Louisville Metro Air Pollution Control District's Proposed Changes to the Ambient Air Quality Monitoring Network

May, 2018

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LMAPCD Proposed Network Changes – Overview 2

Particulate Matter Instrument Proposed Changes 2

LMAPCD Intended Use of Continuous $PM_{2.5}$ Monitors 3

Photochemical Assessment Monitoring Station (PAMS) 4

Kosmosdale SO_2 Site 4

Conclusion 4

LMAPCD Proposed Network Changes – Overview

The Louisville Metro Air Pollution Control District (LMAPCD) is proposing some changes to the ambient monitoring network during the 2018 Network Planning period (July 2018 through June 2019). The main changes being proposed for LMAPCD's ambient monitoring network include changes to the methodology for collecting and reporting particulate matter measurements (both PM_{10} and $PM_{2.5}$) and the installation of additional equipment at the Cannons Lane NCore station for the required Photochemical Assessment Monitoring Station (PAMS) implementation. LMAPCD anticipates implementing a new site in southwestern Jefferson County for measurements of SO_2 in an area identified outside the Southwest Jefferson County SO_2 Nonattainment area. The details concerning these proposed changes are presented below.

Particulate Matter Instrument Proposed Changes

Per the 2017 Network Plan, LMAPCD is currently evaluating the API Teledyne T640 particulate analyzer. The analyzer ran for a period of time in LMAPCD's shop area and was installed at the Firearms Training site as a special purpose monitor in the Spring of 2018. The API T640 analyzer is operating alongside a Met One BAM1020 PM_{10} and $PM_{2.5}$ instrument, as well as collocated FRM Partisol 2025i instruments. If the evaluation of the API T640 particulate analyzer proves to be successful both from an operational and data comparability standpoint, the following changes are expected for calendar year 2019:

- Watson Lane
  - Install API T640 $PM_{2.5}$ analyzer to replace the existing $PM_{2.5}$ BAM1020.
  - Request removal of PM_{10} BAM1020.
- Firearms Training
  - Install API T640x system to measure $PM_{2.5}$ and PM_{10} to replace the existing $PM_{2.5}$ and PM_{10} BAM1020s instruments.
  - Additionally, remove the $PM_{2.5}$ FRM 2025i primary and collocated samplers.
- Cannons Lane
  - Install API T640x system to measure $PM_{2.5}$, PM_{10}, and PM_c to replace the existing $PM_{2.5}$ / PM_{10} BAM pair PM_c system.
  - Additionally, install a $PM_{2.5}$ FRM 2025i collocated sampler for $PM_{2.5}$ FRM collocation.
- Carrithers Middle School
  - Install API T640 $PM_{2.5}$ analyzer to replace the existing $PM_{2.5}$ BAM1020. Upon installation of the API T640 analyzer, the $PM_{2.5}$ monitor will remain a SPM, and LMAPCD is requesting that the $PM_{2.5}$ data not be subject to the $PM_{2.5}$ NAAQS.
- Durrett Lane
  - Install API T640 $PM_{2.5}$ analyzer as a special purpose monitor to evaluate against the existing $PM_{2.5}$ FRM 2025i sampler. The API T640 $PM_{2.5}$ SPM would be in place for one year with $PM_{2.5}$ FRM to assess optical measurement in the near road environment. Some research has indicated that optical measurements of PM may not be accurate in depicting ultrafine particles; therefore this special evaluation period is warranted at the Durrett Lane Near Road site due to the unique emissions characteristics at this site.

Based on discussions with other monitoring agencies, LMAPCD expects the evaluation to result in a switchover from BAM1020 instruments to APIT640 instruments. The evaluation period will also allow for LMAPCD staff to develop standard operating procedures and become more familiar with the instrument before officially implementing throughout the network. The official replacement of BAM1020 instruments with APIT640s will likely occur during the 1st quarter of 2019.

LMAPCD Intended Use of Continuous $PM_{2.5}$ Monitors

Through the remainder of calendar year 2018, LMAPCD will continue to operate BAM1020s for collection of $PM_{2.5}$ and PM_{10} data. All $PM_{2.5}$ data collected with these BAM instruments are subjected to the $PM_{2.5}$ NAAQS with the exception of the Carrithers Middle School $PM_{2.5}$ BAM as it utilizes a sharp cut cyclone, instead of the FEM approved very sharp cut cyclone. As discussed above, LMAPCD plans to replace BAM1020 instruments with APIT T640 or T640x analyzers in 2019. The switch is not intended to result in any changes to the $PM_{2.5}$ NAAQS comparability. While the Carrithers Middle School $PM_{2.5}$ monitor will become an FEM with the installation of the APIT640, the monitor will still be considered a Special Purpose Monitor and ***LMAPCD is requesting that the data not be subject to NAAQS comparison***. Similarly, the installation of an APIT640 instrument at LMAPCD's near road site at Durrett Lane will result in a continuous FEM monitor at that site, but ***LMAPCD is requesting that the data not be subject to NAAQS comparison***. Table 1 and Table 2 serve to clarify the intended use of $PM_{2.5}$ data for calendar years 2018 and 2019, respectively.

Continuous $PM_{2.5}$ Monitors Operated by LMAPCD – Current (2018)								
Site Name	*AQS ID*	*Parameter Code*	*POC*	*Monitor Type*	*Method*	*Primary Monitor?*	*Compare to NAAQS?*	*Eligible for AQI?*
Watson Lane	21-111-0051	88101	3	SLAMS	BAM1020 w/VSCC	Yes	Yes	Yes
Cannons Lane	21-111-0067	88101	3	SLAMS	BAM1020 w/VSCC	No – FRM	Yes	Yes
Carrithers Middle School	21-111-0080	88501	3	SPM	BAM1020 w/SCC	Yes	No	Yes
Firearms Training	21-111-1041	88101	3	SLAMS	BAM1020 w/VSCC	No – FRM	Yes	Yes
Firearms Training	21-111-1041	88101	4	SPM	APIT640	No – FRM	No	No

Table 1 - List of LMAPCD continuous PM2.5 monitors that are currently in place and will remain in place through 2018. Green shading shows those monitors intended for PM2.5 NAAQS comparison with light red shading showing those monitors not intended for PM2.5 NAAQS comparison.

Continuous $PM_{2.5}$ Monitors Operated by LMAPCD – Proposed (2019)								
Site Name	*AQS ID*	*Parameter Code*	*POC*	*Monitor Type*	*Method*	*Primary Monitor?*	*Compare to NAAQS?*	*Eligible for AQI?*
Watson Lane	21-111-0051	88101	3	SLAMS	APIT640	Yes	Yes	Yes
Cannons Lane	21-111-0067	88101	3	SLAMS	APIT640x	No – FRM	Yes	Yes
Durrett Lane (Near Road)	21-111-0075	88101	3	SPM	APIT640	No – FRM	No	Yes
Carrithers Middle School	21-111-0080	88101	3	SPM	APIT640	Yes	No	Yes
Firearms Training	21-111-1041	88101	3	SLAMS	APIT640x	Yes	Yes	Yes

Table 2 – A proposed list of LMAPCD continuous PM2.5 monitors expected to be in place for 2019. Green shading shows those monitors intended for PM2.5 NAAQS comparison with light red shading showing those monitors not intended for PM2.5 NAAQS comparison.

Photochemical Assessment Monitoring Station (PAMS)

Per EPA requirements, PAMS monitoring is required for the Louisville MSA and shall be conducted at the Cannons Lane NCore monitoring station. Per PAMS requirements, the following additional parameters are required to be installed at the Cannons Lane NCore station by June 1, 2019:

- Continuous VOCs via Auto GC
- Ultra Violet Solar Radiation
- Mixing Height data via Ceilometer
- Barometric Pressure
- Carbonyls

In order to accommodate the new instrumentation for PAMS, it is likely that an additional shelter will be needed at the Cannons Lane site. Due to funding limitations, the EPA is not able to provide funding for all equipment at one time. Instead, the funding will likely be provided over a multi-year period. As such, it is unlikely that all of the required instrumentation will be operational by the June 1, 2019 deadline. APCD plans to purchase the additional PAMS instrumentation in the following order of priority:

1.) Install new shelter to house new equipment
2.) Install Auto GC at CLAMS with goal of being operational by 6/1/19
3.) Install a ceilometer at CLAMS with goal of being operational by 6/1/19
4.) Install a barometric pressure sensor at CLAMS with goal of being operational by 6/1/19
5.) Install an Ultra Violet pyranometer at CLAMS with goal of being operational by 6/1/20
6.) Install instrumentation to measure Carbonyls at CLAMS with goal of being operational by 6/1/20

LMAPCD will work as diligently as possible to install and operate the new PAMS instrumentation so that meaningful, valid data can be collected and reported to EPA's AQS database. Funding constraints may limit the amount of time that LMAPCD staff have to become familiar with the new instrumentation. As such, LMAPCD does not plan to report these PAMS data to EPA's database until there is adequate confidence in the data being collected.

Kosmosdale SO_2 Site

APCD has received approval from EPA for the installation of an additional site for monitoring SO_2 concentrations in an area outside the Southwest Jefferson County SO_2 Nonattainment area. Although installation and operation of the new site was anticipated by January 1, 2018, delays in approval of the SIP submittal for the nearby Southwest Jefferson County SO_2 Nonattainment area by EPA have delayed the project. APCD will continue to work with EPA, KYDAQ, and permitted facilities to install the site and monitoring equipment in a timely manner.

Conclusion

The majority of the changes being proposed for the Network Planning period (July 2018 – June 2019) do not significantly alter LMAPCD's criteria pollutant network. Most of the changes involve altering the methodology for collecting and reporting $PM_{2.5}$ and PM_{10} data. The most substantial change to LMAPCD's network will be the installation of several pieces of equipment at the Cannons Lane NCore station to meet PAMS requirements. The PAMS instrumentation is new to most state, local, and tribal agencies, and as such, additional effort will likely be needed to make sure that the instrumentation is producing meaningful, valid data. In an effort to ensure that the Louisville Metropolitan Statistical Area (MSA) continues to meet minimum monitoring requirements, Table 3 provides a summary of the number of ambient air quality monitoring sites in operation for each pollutant group within the Louisville MSA. The following changes are noted between the current and proposed changes:

- Increase of one $PM_{2.5}$ site is result of Carrithers $PM_{2.5}$ non-FEM BAM being converted to the FEM approved T640. While LMAPCD is requesting that the Carrithers $PM_{2.5}$ T640 not be comparable to the $PM_{2.5}$ NAAQS, it is listed in Table 3 since it is a $PM_{2.5}$ FEM.
- Decrease of one PM_{10} site is result of removing Watson Lane PM_{10}BAM from operation
- Increase of one SO_2 site is result of proposed addition of the Kosmosdale site
- Increase of one PAMS site is result of proposed addition of PAMS instrumentation at Cannons Lane

As can be seen in Table 3, the Louisville MSA continues to meet the EPA minimum monitoring requirements through the collective efforts of the Indiana Department of Environmental Management (IDEM), Kentucky Division for Air Quality (KDAQ), and the LMAPCD. It should also be noted that the operation of ambient air quality monitors by the LMAPCD alone meets the EPA minimum monitoring requirements.

Louisville / Jefferson County MSA Monitoring Requirements

	O_3	$PM_{2.5}$	PM_{10}	PM_c	SO_2	NO_2	CO	Toxics	PAMS
# Sites Required by CFR	2	3	2-4	1	1	2	2	0	1
# Sites Before proposed Changes	7 (3)	7 (4)	4 (3)	1 (1)	4 (3)	2 (2)	2 (2)	1 (1)	0 (0)
# Sites After proposed Changes	7 (3)	8 (5)	3 (2)	1 (1)	5 (4)	2 (2)	2 (2)	1 (1)	1 (1)

Table 3 - Summary of monitoring requirements in Louisville / Jefferson County MSA compared to number of monitors / sites before and after network changes. Numbers in parenthesis represents number of sites that APCD operates (versus total number in MSA).

Appendix E - Part B
LMAPCD Equipment Inventory

Louisville Air Pollution Control District Ambient Monitoring Group Instrument & Equipment Inventory - May, 2018						
Location	**Instrument Type**	**Manufacturer**	**Model**	**Serial Number**	**Condition**	**Status**
Carrithers	Calibrator	API	T703	255	Good	In Use
Carrithers	Datalogger	ESC Agilaire LLC	8832	4411	Fair	In Use
Carrithers	O3 Analyzer	API	T400	315	Good	In Use
Carrithers	PM	Met One	BAM	T18984	Good	In Use
Carrithers	RH/Temp Probe	RM Young	41382	n/a	Good	In Use
Carrithers	RH/Temp Sensor	Vaisala	HMW93D	n/a	Good	In Use
Carrithers	Shelter	EKTO Mfg.	81012	4234-1	Fair	In Use
Carrithers	Wind Monitor	RM Young	05103VM-42	n/a	Good	In Use
CLAMS	Anemometer	RM Young	85000	UB00002568	Good	In Use
CLAMS	Calibrator	API	T700U	107	Good	In Use
CLAMS	CO Analyzer	Thermo	48i-TLE	0814429-062	Fair	In Use
CLAMS	Datalogger	ESC Agilaire LLC	8832	4410	Good	In Use
CLAMS	Meteorology Tower	Aluma Tower	T-35H	AP-29071-U-4	Good	In Use
CLAMS	NO2 Analyzer	API	T500U	169	Good	In Use
CLAMS	Noy Analyzer	Thermo	42i-Y	0814428-734	Fair	In Use
CLAMS	O3 Analyzer	API	T400	1467	Good	In Use
CLAMS	PM	Met One	Super SASS	1046	Good	In Use
CLAMS	PM	Thermo	2025i	20607	Good	In Use
CLAMS	PM	Met One	SASS	3567	Fair	In Use
CLAMS	PM	Met One	SASS	6079	Fair	In Use
CLAMS	PM	URG	3000N	BN-251	Fair	In Use
CLAMS	PM	URG	3000N	BN-933	Fair	In Use
CLAMS	PM	Met One	BAM	K19862	Fair	In Use
CLAMS	PM	Met One	BAM	K19863	Fair	In Use
CLAMS	Pyranometer	Met One	394	34257	Good	In Use
CLAMS	RadNet	HI-Q	HVP-4004BRL-S	17603	Fair	In Use
CLAMS	Rain	Met One	370	U10772	Good	In Use
CLAMS	RH/Temp Probe	RM Young	41382	TS-14425	Good	In Use
CLAMS	RH/Temp Sensor	Vaisala	HMW93D	H05200002	Good	In Use
CLAMS	Shelter	Modular Connections	MCP-296	MC2519	Good	In Use
CLAMS	SO2 Analyzer	API	T100U	276	Good	In Use

LMAPCD Equipment Inventory
(Continued)

Louisville Air Pollution Control District Ambient Monitoring Group Instrument & Equipment Inventory - May, 2018						
Location	Instrument Type	Manufacturer	Model	Serial Number	Condition	Status
CLAMS	TEOM Shelter	EKTO Mfg.	432-SP	3200-7	Poor	In Use
CLAMS	TEOM Shelter	EKTO Mfg.	432-SP	3535-6	Good	In Use
CLAMS	Wind Monitor	RM Young	5305AQ	n/a	Good	In Use
CLAMS	Zero Air	API	T701H	773	Fair	In Use
FireArms	Anemometer	RM Young	85000	UB3773	Good	In Use
FireArms	Auto GC Air generator	Chromatotec	airmoPure D	56430717	Good	In Use
FireArms	Auto GC C3-C6	Chromatotec	airmoVOC A21022	56410717	Good	In Use
FireArms	Auto GC C6-C12	Chromatotec	airmoVOC C6-C12 A21022	26400717	Good	In Use
FireArms	Auto GC Calibrator	Chromatotec	airmoCal	56440717	Good	In Use
FireArms	Calibrator	API	T700	289	Good	In Use
FireArms	Datalogger	ESC Agilaire LLC	8832	4294	Fair	In Use
FireArms	Datalogger	ESC Agilaire LLC	8872	n/a	Good	In Use
FireArms	PM	API	T640	151	Good	In Use
FireArms	PM	Thermo	2025i	20612	Good	In Use
FireArms	PM	Thermo	2025i	20614	Good	In Use
FireArms	PM	Met One	BAM	N2946	Fair	In Use
FireArms	PM	Met One	BAM	T18981	Good	In Use
FireArms	RH/Temp Sensor	Vaisala	HMW93D	n/a	Good	In Use
FireArms	Shelter	EKTO Mfg.	8812	4222	Good	In Use
FireArms	SO2 Analyzer	API	T100	1322	Good	In Use
FireArms	Zero Air	API	T701M	647	Good	In Use
Near Road	Anemometer	RM Young	85000	4675	Fair	In Use
Near Road	Calibrator	API	T700U	106	Good	In Use
Near Road	CO Analyzer	API	T300U	155	Fair	In Use
Near Road	Datalogger	ESC Agilaire LLC	8832	4293	Fair	In Use
Near Road	Meteorology Tower	Aluma Tower	T-135	AT-213072-Y-6-1	Good	In Use
Near Road	NO2 Analyzer	API	T500U	168	Good	In Use
Near Road	PM	Thermo	2025i	20608	Good	In Use
Near Road	RH/Temp Probe	RM Young	41382	25029	Fair	In Use
Near Road	RH/Temp Sensor	Vaisala	HMW93D	n/a	Good	In Use
Near Road	Shelter	CAS	CAS	3200-7	Good	In Use

LMAPCD Equipment Inventory
(Continued)

Louisville Air Pollution Control District Ambient Monitoring Group Instrument & Equipment Inventory - May, 2018						
Location	Instrument Type	Manufacturer	Model	Serial Number	Condition	Status
Near Road	Wind Monitor	RM Young	05305V	128356	Fair	In Use
Near Road	Zero Air	API	T701M	839	Good	In Use
Southwick	Baro Pressure	RM Young	61302V	BPA1240	Good	In Use
Southwick	Meteorology Tower	Aluma Tower	Meteorology Tower	n/a	Good	In Use
Southwick	PM	Thermo	2025B	20450	Fair	In Use
Southwick	PM	Thermo	2025B	21665	Fair	In Use
Southwick	PM	Met One	BAM	T18983	Good	In Use
Southwick	Rain	Met One	0.1 Rain Gauge	E5009	Good	In Use
Southwick	RH/Temp Probe	RM Young	41372VC	Y490092	Fair	In Use
Southwick	Shelter	Met One	BAM Shelter	n/a	Good	In Use
Southwick	TEOM Shelter	EKTO Mfg.	432-SP	3408-6	Good	In Use
Southwick	TEOM Shelter	EKTO Mfg.	432-SP	3408-7	Good	In Use
Watson	Anemometer	RM Young	85000	n/a	Good	In Use
Watson	Calibrator	API	T700	1620	Good	In Use
Watson	Datalogger	ESC Agilaire LLC	8832	4291	Fair	In Use
Watson	O3 Analyzer	API	T400	1468	Good	In Use
Watson	PM	Met One	BAM	N3593	Fair	In Use
Watson	PM	Met One	BAM	T18977	Good	In Use
Watson	RH/Temp Probe	RM Young	41382	n/a	Good	In Use
Watson	RH/Temp Sensor	Vaisala	HMW93D	J0871073	Good	In Use
Watson	Shelter	EKTO Mfg.	8812	3728-1	Good	In Use
Watson	SO2 Analyzer	API	T100	1321	Good	In Use
Watson	Zero Air	API	T701M	648	Good	In Use
Shop	Air Toxics FTIR	IMACC	M-ZSE12-180	M0015	Good	Spare
Shop	Air Toxics Sampler	Thermo	Miran Saphire	79545411	Good	Spare
Shop	Anemometer	Met One	50.5	B-1031	Poor	Spare
Shop	Anemometer	RM Young	85000	UB-1309	Good	Spare
Shop	Anemometer	RM Young	5305AQ	VW101749	Good	Spare
Shop	Anemometer	Met One	50.5	Y3338	Good	Spare
Shop	Calibrator	API	T750	054	Good	In Use
Shop	Calibrator	API	T700E	1038	Good	In Use

LMAPCD Equipment Inventory
(Continued)

Louisville Air Pollution Control District Ambient Monitoring Group Instrument & Equipment Inventory - May, 2018						
Location	Instrument Type	Manufacturer	Model	Serial Number	Condition	Status
Shop	Calibrator	API	T700	1619	Good	In Use
Shop	Calibrator	API	T700U	174	Good	In Use
Shop	Calibrator	API	T700	290	Good	In Use
Shop	CO Analyzer	API	T300U	281	Good	In Use
Shop	Datalogger	ESC Agilaire LLC	8832	2713K	Fair	In Use
Shop	Datalogger	ESC Agilaire LLC	8832	4691K	Fair	In Use
Shop	Flow Standard	MesaLab	Bios Dry Cal	105393	Fair	In Use
Shop	Flow Standard	AliCat	FP-25	148162	Good	In Use
Shop	Flow Standard	Chinook	SLP	170606	Good	In Use
Shop	Flow Standard	Chinook	SLP	170607	Good	In Use
Shop	Flow Standard	Fluke	Fluke	2213	Good	In Use
Shop	Flow Standard	MesaLab	Delta Cal	465	Fair	In Use
Shop	Flow Standard	MesaLab	Delta Cal	466	Fair	In Use
Shop	Flow Standard	Chinook	SLP	M41005	Fair	In Use
Shop	Flow Standard	Chinook	SLP	M41006	Fair	In Use
Shop	Flow Standard	Chinook	SLP	M41007	Fair	In Use
Shop	Flow Standard	Chinook	SLP	M70204	Fair	In Use
Shop	Lab Fridge	Thermo	REL1204A	155472601160526	Good	In Use
Shop	Met Station	Met One	Portable	5876	Fair	Spare
Shop	Met Station	Met One	Portable	E5678	Good	Spare
Shop	NO2 Analyzer	API	T500U	170	Good	Spare
Shop	Noy Analyzer	API	T200U	316	Good	Spare
Shop	O3 Analyzer	API	T400	316	Good	In Use
Shop	O3 Analyzer	Thermo	49C	413906-381	Poor	Spare
Shop	O3 Analyzer	Thermo	49C	417007-061	Poor	Spare
Shop	O3 Analyzer	Thermo	49iPS	617817-229	Good	In Use
Shop	O3 Analyzer	Thermo	49i	617817-230	Fair	Spare
Shop	O3 Analyzer	Thermo	49C	70020-364	Good	In Use
Shop	O3 Analyzer	Thermo	49C	74462-376	Poor	Spare
Shop	PM	URG	3000N	1045	Fair	Spare
Shop	PM	Thermo	2025B	22560	Fair	Parts

LMAPCD Equipment Inventory
(Continued)

Louisville Air Pollution Control District Ambient Monitoring Group Instrument & Equipment Inventory - May, 2018						
Location	Instrument Type	Manufacturer	Model	Serial Number	Condition	Status
Shop	PM	Met One	SASS	6080	Fair	Spare
Shop	PM	Met One	BAM	H1710	Fair	Spare
Shop	Pump	Rocker	Rocker	B001	Fair	Spare
Shop	Pump	Rocker	Rocker	B002	Fair	In Use
Shop	Pump	Rocker	Rocker	C031	Fair	Spare
Shop	Pump	Rocker	Rocker	H005	Fair	In Use
Shop	Pyranometer	Met One	394	33927	Good	Spare
Shop	Pyranometer	Met One	PSP	33927F3	Fair	Spare
Shop	Pyranometer	Met One	PSP	34257F3	Good	Spare
Shop	Rain	RM Young	52202	TB03206	Good	Spare
Shop	RH/Temp Probe	RM Young	41382	21011	Good	Spare
Shop	RH/Temp Sensor	Vaisala	HMW93D	n/a	Good	Spare
Shop	RH/Temp Sensor	Vaisala	HMW93D	N1540017	Fair	In Use
Shop	RH/Temp Standard	Vaisala	HPM	10013	Fair	In Use
Shop	RH/Temp Standard	Vaisala	HPM	J0871073	Fair	In Use
Shop	RH/Temp Transmitter	Vaisala	HMW71Y	W3650008	Fair	Spare
Shop	RH/Temp Transmitter	Vaisala	HMW71Y	X0840020	Fair	Spare
Shop	SO2 Analyzer	API	T100U	081	Fair	In Use
Shop	SO2 Analyzer	Thermo	43i-TLE	814428-732	Fair	Spare
Shop	Temp Probe	RM Young	41342VF	41376A	Fair	Spare
Shop	Temp Probe	RM Young	41342VF	TS05123	Good	Spare
Shop	Vehicle	Ford	F250	1268	Good	In Use
Shop	Vehicle	Ford	Focus	1706	Good	In Use
Shop	Vehicle	Ford	Transit	2116	Good	In Use
Shop	Vehicle	Ford	F350	2966	Poor	In Use
Shop	Vehicle	Ford	Ranger	3114	Poor	In Use
Shop	Vehicle	Ford	Explorer	3500	Fair	In Use
Shop	Vehicle	Ford	Escape	3700	Fair	In Use
Shop	Wind Monitor	RM Young	05103VM	WM101749	Spare	Spare
Shop	Wind Monitor	RM Young	05103VM	WM47808	Spare	Spare
Shop	Zero Air	API	T701M	604	Good	In Use

LMAPCD Equipment Inventory
(Continued)

Louisville Air Pollution Control District Ambient Monitoring Group Instrument & Equipment Inventory - May, 2018						
Location	Instrument Type	Manufacturer	Model	Serial Number	Condition	Status
Shop	Zero Air	API	T751	62	Good	In Use
Shop	Zero Air	API	T701M	801	Good	In Use
Shop	Zero Air	API	T701M	802	Good	Spare
Warehouse	Air Toxics UV	IMACC	Air Toxics UV	Air Toxics UV	Fair	Not In Use
Warehouse	Analyzer	EcoTech	300	1586	Poor	Not In Use
Warehouse	Calibrator	Thermo	146C	0417007-062	Poor	Not In Use
Warehouse	Calibrator	Thermo	146i	0814428-735	Fair	Not In Use
Warehouse	Calibrator	Thermo	146C	382	Poor	Not In Use
Warehouse	Calibrator	EcoTech	6100	4012	Poor	Not In Use
Warehouse	Calibrator	Thermo	146C	70386-365	Poor	Not In Use
Warehouse	CO Analyzer	Thermo	48C	351	Poor	Not In Use
Warehouse	CO Analyzer	Thermo	48C	417007-060	Poor	Not In Use
Warehouse	CO Analyzer	Thermo	48i-TLE	617817-228	Fair	Not In Use
Warehouse	CO Analyzer	Thermo	48C	67474-356	Poor	Not In Use
Warehouse	CO Analyzer	Thermo	48C	68840-361	Poor	Not In Use
Warehouse	Datalogger	ESC Agilaire LLC	8816	1917	Fair	Not In Use
Warehouse	Datalogger	ESC Agilaire LLC	8816	1971	Fair	Not In Use
Warehouse	Datalogger	ESC Agilaire LLC	8816	1972	Fair	Not In Use
Warehouse	Datalogger	ESC Agilaire LLC	8816	1973	Fair	Not In Use
Warehouse	Datalogger	ESC Agilaire LLC	8816	2423	Fair	Not In Use
Warehouse	Datalogger	ESC Agilaire LLC	8816	2764	Fair	Not In Use
Warehouse	Datalogger	ESC Agilaire LLC	8816	3303	Poor	Not In Use
Warehouse	Datalogger	ESC Agilaire LLC	8816	3304	Poor	Not In Use
Warehouse	Datalogger	ESC Agilaire LLC	8816	3305	Poor	Not In Use
Warehouse	Datalogger	ESC Agilaire LLC	8816	3306	Fair	Not In Use
Warehouse	Datalogger	ESC Agilaire LLC	8816	3307	Fair	Not In Use
Warehouse	Datalogger	ESC Agilaire LLC	8816	3308	Fair	Not In Use
Warehouse	Datalogger	ESC Agilaire LLC	8816	3801	Good	Not In Use
Warehouse	Datalogger	ESC Agilaire LLC	8832	4291	Fair	Not In Use
Warehouse	Datalogger	ESC Agilaire LLC	8816	4422	Fair	Not In Use
Warehouse	Datalogger	ESC Agilaire LLC	8816	4423	Fair	Not In Use

LMAPCD Equipment Inventory
(Continued)

Louisville Air Pollution Control District Ambient Monitoring Group Instrument & Equipment Inventory - May, 2018						
Location	Instrument Type	Manufacturer	Model	Serial Number	Condition	Status
Warehouse	Datalogger	ESC Agilaire LLC	8816	4424	Fair	Not In Use
Warehouse	Datalogger	ESC Agilaire LLC	8832	5058	Poor	Not In Use
Warehouse	Datalogger	ESC Agilaire LLC	8832	A1014	Good	Not In Use
Warehouse	Meteorology Tower	Aluma Tower	Meteorology Tower	n/a	Good	Not In Use
Warehouse	NO2 Analyzer	Thermo	42C	070415-365	Poor	Not In Use
Warehouse	NO2 Analyzer	API	T200UP	085	Good	Not In Use
Warehouse	NO2 Analyzer	API	T200	341	Fair	Not In Use
Warehouse	NO2 Analyzer	EcoTech	Ecotech Serinus	40-10-51	Poor	Not In Use
Warehouse	NO2 Analyzer	Thermo	42C	70979-367	Poor	Not In Use
Warehouse	O3 Analyzer	Thermo	49C	43374-269	Poor	Not In Use
Warehouse	O3 Analyzer	Thermo	49C	47646-280	Poor	Not In Use
Warehouse	O3 Analyzer	Thermo	49C	64282-342	Poor	Not In Use
Warehouse	PM	Thermo	2025B	21310	Fair	Not In Use
Warehouse	PM	Thermo	2025B	21656	Fair	Not In Use
Warehouse	PM	Thermo	2025B	21666	Fair	Not In Use
Warehouse	PM	Met One	SASS	3565	Fair	Not In Use
Warehouse	PM	Met One	BAM	N3596	Fair	Not In Use
Warehouse	Shelter	EKTO Mfg.	8812	3876-1	Poor	Not In Use
Warehouse	SO2 Analyzer	Thermo	43C	436610-205	Poor	Not In Use
Warehouse	SO2 Analyzer	Thermo	43C	518612-095	Poor	Not In Use
Warehouse	SO2 Analyzer	Thermo	43C	69873-364	Poor	Not In Use
Warehouse	TEOM	R&P	1400a	230750005	Poor	Not In Use
Warehouse	TEOM	R&P	1400a	23746	Poor	Not In Use
Warehouse	TEOM	R&P	1400a	23748	Poor	Not In Use
Warehouse	TEOM	R&P	1400ab	24059	Poor	Not In Use
Warehouse	TEOM	R&P	1400ab	24097	Poor	Not In Use
Warehouse	TEOM	R&P	1400a	24601	Poor	Not In Use
Warehouse	TEOM	R&P	1400ab	24885	Poor	Not In Use
Warehouse	TEOM	R&P	1400ab	24926	Poor	Not In Use
Warehouse	TEOM Shelter	EKTO Mfg.	432-SP	3278-10	Good	Not In Use
Warehouse	TEOM Shelter	EKTO Mfg.	432-SP	3278-9	Good	Not In Use

LMAPCD Equipment Inventory
(Continued)

Louisville Air Pollution Control District Ambient Monitoring Group Instrument & Equipment Inventory - May, 2018						
Location	Instrument Type	Manufacturer	Model	Serial Number	Condition	Status
Warehouse	Zero Air	API	T701M	835	Poor	Not In Use
Warehouse	Zero Air	API	T701M	837	Poor	Not In Use

APPENDIX F

KDAQ INTENDED USE OF CONTINUOUS $PM_{2.5}$ FEMS

Appendix F
KDAQ Intended Use of Continuous $PM_{2.5}$ FEMs

Historically, continuous $PM_{2.5}$ monitors that are designated as Federal Equivalent Methods (FEMs) have been excluded from comparisons to the $PM_{2.5}$ NAAQS, as long as these monitors were specified as special-purpose monitors (SPMs). Data from these monitors was used for reporting of the AQI. Monitors could remain designated as SPMs for a period of two years of operation at each site. However, after that two-year period, the data was eligible for comparison to the NAAQS, regardless of monitor-type designation.

In December 2012, a new PM NAAQS and set of monitoring rules were finalized. These new monitoring rules amended the previous requirement to compare all data from FEMs collected after a period of two-years to the NAAQS. Instead, agencies could operate a continuous $PM_{2.5}$ FEM for longer than two years and could elect to exclude the data from NAAQS-comparisons, provided that the monitor did not meet certain performance specifications. Data from monitors established for less than two years and designated as SPM remain ineligible for attainment decisions. Specifically, the final rule allows certain continuous $PM_{2.5}$ FEM data to be excluded if:

- the monitor does not meet performance criteria when compared to the data collected from collocated Federal Reference Methods (FRMs);
- the monitoring agency requests exclusion of data; and,
- the EPA Regional Office approves exclusion of the data.

Regardless of whether an exclusion is sought, each agency must address the use of all continuous $PM_{2.5}$ FEMs in the network. Each monitor must be properly referenced by a set of parameter codes, primary monitor designations, and monitor-types.

During the upcoming monitoring year, KDAQ plans to install FEM Teledyne-API model T640 $PM_{2.5}$ mass monitors at four sites: Elizabethtown, Hazard, Lexington Primary, and Ed Spear Park (Smiths Grove) sites. KDAQ intends to eventually replace all non-FEM TEOMs with FEM T640s within the next few years. As such, T640s may be installed at additional sites, as resources allow. KDAQ requests EPA-approval to exclude data collected from all FEM T640 monitors from NAAQS comparisons for the allowable two-year comparability studies.

The monitor designations for Teledyne-API T640 continuous $PM_{2.5}$ FEMs that will be operated by KDAQ are summarized in the chart below:

Elizabethtown (21-093-0006); Hazard (21-193-0003); Lexington Primary(21-067-0012); Ed Spear Park (21-227-0009)								
Scenario	**Parameter Name**	**Parameter Code**	**Pollution Occurrence Code (POC)**	**Monitor Type**	**Primary Monitor (Collocation)**	**Used for substitutions of missing primary data?**	**Used for NAAQS Comparisons?**	**Eligible for AQI?**
PM2.5 Continuous FEM is being tested and is less than 24 old; FRM is retained as the Primary monitor.	PM2.5 Local Conditions	88101	3	SPM & Non-Regulatory	FRM	No	No	Yes

APPENDIX G

NEAR-ROAD MONITORING

Appendix G
Part A - Near-Road Monitoring

On February 9, 2010, the EPA released a new NO_2 Final Rule and a new set of monitoring requirements. Under the new monitoring requirements, State and Local agencies are required to establish NO_2 near-road monitoring stations based upon core based statistical area (CBSA) populations and traffic metrics.

Specifically, the final rule required:

- 1 near-road monitor in CBSAs with populations greater than or equal to 500,000; and
- 2 near-road monitors in CBSAs with populations greater than or equal to 2,500,000.

Additionally, the final rule required:

- 2 near-road monitors for any road segment that has an annual average daily traffic (AADT) count of 250,000 or more.

Similarly, the EPA revised the $PM_{2.5}$ NAAQS and monitoring rule on December 14, 2012, and the CO monitoring rule on August 31, 2011. Together, these rules require CO and $PM_{2.5}$ monitoring to be established at near-road sites for any CBSA with a population of one-million or greater. Ultimately, near-road sites are intended to be multi-pollutant sites. These sites are used to characterize the impacts vehicle exhaust and traffic patterns on public health.

In March 2013, the EPA finalized the use of a "phased" approach for establishing NO_2 near-road monitoring sites across the Nation. The phased approach necessitates:

- Phase 1: One required near-road monitor in CBSAs with a population of 1,000,000 or more must be established by January 1, 2014.
- Phase 2: Any second required near-road monitor in CBSAs that have a population greater than 2,500,000, or have a population of 500,000 or greater and have a traffic segment with an AADT of 250,000 or more, must be established by January 1, 2015.
- Phase 3: Required sites in remaining CBSAs with populations of 500,000 or more must be established by January 1, 2017.

Based upon population estimates and AADT counts, near-road monitors were required to be established in the following CBSAs during the implementation of Phase 1. No Phase 2 monitors are required in Kentucky.

CBSA Name (500,000 or more people)	2015 CBSA Population Estimate*	Highest Road Segment 2-Way AADT for CBSA**	Number of Monitors Required in CBSA
Cincinnati-Middletown, OH-KY-IN	2,128,603	193,399	1
Louisville-Jefferson County, KY-IN	1,251,351	166,432	1

*Source: US Census Bureau, 2015 Population Estimates (Last accessed: April 5, 2016)

**Source: KYTC Traffic Database. http://datamart.business.transportation.ky.gov/EDSB_SOLUTIONS/CTS/. Last accessed: June 2015

The determination of the final locations of near-road monitoring locations within these CBSAs was a cooperative effort between multiple State and Local Agencies. The exact location of each site was determined using the following criteria:

- Fleet mix
- Roadway design
- Traffic congestion patterns
- Local topography
- Meteorology
- Population exposure
- Employee and public safety
- Site logistics

The requirement for a near-road site in the Cincinnati, OH-KY-IN MSA is fulfilled by a Memorandum of Agreement (MOA). The site is located in Ohio and is operated by the Southwest Ohio Air Quality Agency.

The near-road site in the Louisville-Jefferson County, KY-IN MSA has been established and is operated by the Louisville Metro Air Pollution Control District (LMAPCD). Specifics regarding this site are included in the site detail pages of this Annual Network Plan.

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APPENDIX H

KENTUCKY SO_2 PWEI VALUES

Appendix H
Kentucky SO_2 PWEI Values

40 CFR 58, Appendix D, requires that a minimum number of SO_2 monitors be operated based upon a Population Weighted Emissions Index (PWEI) values. This index, which is calculated for each Core Based Statistical Area (CBSA), is calculated by multiplying the population of each CBSA and the total amount of SO_2, in tons per year, that is emitted within the CBSA, based upon aggregated county level emissions data from the National Emissions Inventory (NEI). The result is then divided by one million to provide the PWEI value, which is expressed in a unit of million persons-tons per year.

The minimum number of monitors required are:

- 3 monitors in CBSAs with index values of 1,000,000 or more;
- 2 monitors in CBSAs with index values less than 1,000,000 but greater than 100,000; and
- 1 monitor in CBSAs with index values greater than 5,000.

Additionally, the EPA Regional Administrator may, at their discretion, require additional monitors beyond the minimum required by PWEI calculations. However, Kentucky currently does not have any Regional Administrator required SO_2 monitors.

Based upon Kentucky's calculated PWEI values, the following CBSAs require SO_2 monitors:

Kentucky CBSAs	2015 PWEI* (million persons-tons per year)	Number of SO_2 Monitors Required	Number of SO_2 Monitors Present	Kentucky Site Name	Kentucky AQS ID
Cincinnati, OH-KY-IN	380,617	2	6**	NKU	21-037-3002
Evansville, IN-KY	7,771	1	1	Baskett	21-101-0014
Huntington-Ashland, WV-KY-OH	4,553	1	2	Ashland Primary	21-019-0017
				Worthington	21-089-0007
Lexington-Fayette, KY	3,522	1	2	Lexington Primary	21-067-0012
				Nicholasville	21-113-0001
Louisville-Jefferson County, KY-IN	60,030	1	3***	Watson Lane	21-111-0051
				Cannons Lane	21-111-0067
				Firearms Training	21-111-1041
Paducah, KY-IL	5,514	1	1	Jackson Purchase	21-145-1024

* 2015 PWEI calculated from 2013 USCB Population Estimates and 2011 NEI.
** Additional monitors operated by SWOAQA in Ohio.
***Monitors operated by the Louisville Metro Air Pollution Control District

APPENDIX I

EPA CASTNET STATIONS IN KENTUCKY

Appendix I
EPA CASTNET Stations in Kentucky

The Clean Air Status and Trends Network (CASTNET) is a nation-wide, long-term monitoring network designed to measure acidic pollutants and ambient ozone concentrations in rural areas. CASTNET is managed collaboratively by the Environmental Protection Agency – Clean Air Markets Division (EPA), the National Park Service – Air Resources Division (NPS), and the Bureau of Land Management – Wyoming State Office (BLM-WSO). In addition to EPA, NPS, and BLM-WSO, numerous other participants provide network support including tribes, other federal agencies, States, private land owners, and universities. More information about CASTNET can be found at: https://www.epa.gov/castnet

KDAQ does not operate nor serve as the Primary Quality Assurance Organization for any site in the CASTNET network. However, KDAQ does maintain a cooperative relationship with the staff of Mammoth Cave National Park. At the request of KDAQ, the NPS has designated the ozone monitor as the "Maximum O_3 Concentration" site for the Bowling Green, KY MSA. More information about the Mammoth Cave site can be found in the site detail pages of the Annual Network Plan.

KDAQ requested that EPA designate the CASTNET ozone monitor at the Cadiz site (21-221-9991) as the "Maximum O_3 Concentration" site for the Clarksville, TN-KY MSA. EPA agreed to the change and has since updated the metadata for the monitor in AQS.

Clean Air Status & Trends Network (CASTNET)

Kentucky Ozone Monitors

Monitor ID	Monitor Name	County/ Metropolitan Statistical Area	Designation	Monitoring Scale
21-061-0501	Mammoth Cave National Park	Edmonson/ Bowling Green, KY MSA	CASTNET Non-EPA Federal Maximum O_3 Concentration*	Regional
21-175-9991	Crockett	Morgan/ Not in a MSA	CASTNET EPA	Regional
21-221-9991	Cadiz	Trigg/ Clarksville, TN-KY MSA	CASTNET EPA Maximum O_3 Concentration**	Regional
21-229-9991	Mackville (POC 1)	Washington/ Not in a MSA	CASTNET EPA	Regional
21-229-9991	Mackville Collocated (POC 2)	Washington/ Not in a MSA	CASTNET- QA Collocated*** EPA	Regional

* Maximum Ozone Concentration Site for the Bowling Green, KY MSA

** Maximum Ozone Concentration site for the Clarksville, TN-KY MSA

***Not usable for NAAQS comparisons

APPENDIX J

KDAQ EQUIPMENT INVENTORY

Appendix J
KDAQ Equipment Inventory

Location	Item	Description	Condition	Comments
21st & Greenup	PM2.5 Sampler	Partisol Plus 2025 Sequential	Good	In Use
21st & Greenup	PM2.5 Sampler	Partisol Plus 2025 Sequential	Fair	In Use
Baskett	Calibrator	Teledyne-API 700 E	Fair	In Use
Baskett	O3 Monitor	Teledyne-API T400	Good	In Use
Baskett	PM10 Sampler	Partisol 2000	Good	In Use
Baskett	PM2.5 Continuous	Teledyne API T640	Good	In Use
Baskett	PM2.5 Sampler	Partisol Plus 2025i Sequential	Good	In Use
Baskett	Zero Air Unit	Teledyne-API 701E Zero Air	Good	In Use
Baskett	SO2 Monitor	API100E	Good	In Use
Baskett	Datalogger	Agilaire 8872 Data Logger	Good	In Use
Bloodworth	Air Toxics- VOCs	Xontech 911a	Good	In Use
Bloodworth	PM10 Sampler	Partisol 2000	Good	In Use
Buckner	Datalogger	ESC 8832 Data Logger	Good	In Use
Buckner	O3 Monitor	Teledyne-API T400	Good	In Use
Buckner	Photometer	Teledyne-API 703E	Good	In Use
Buckner	Zero Air Unit	Teledyne-API 701 Zero Air	Fair	In Use
East Bend	Datalogger	ESC Model 8832	Good	In Use
East Bend	Meteorological- Probe	41372VC RH/Temp	Fair	In Use
East Bend	O3 Monitor	Teledyne-API T400	Good	In Use
East Bend	Photometer	Teledyne-API 703E	Good	In Use
East Bend	Zero Air Unit	Teledyne-API 701 Zero Air	Fair	In Use
EKU	Lead Sampler- TSP	Tisch Model TE-5170DV-BL TSP	Good	In Use
EKU	Lead Sampler- TSP	Tisch Model TE-5170DV-BL TSP	Good	In Use
E-town	Datalogger	ESC Model 8832	Good	In Use
E-town	O3 Monitor	Teledyne-API T400	Good	In Use
E-town	Photometer	Teledyne-API 703E	Good	In Use
E-town	PM2.5 Continuous	Thermo Scientific TEOM 1405	Good	In Use
E-town	PM2.5 Sampler	Partisol Plus 2025 Sequential	Good	In Use
E-town	PM2.5 Sampler	Partisol Plus 2025 Sequential	Good	In Use
E-town	Zero Air Unit	Teledyne-API 701 Zero Air	Good	In Use
FIVCO	Air Toxics- VOCs/Carbonyls	ATEC 2200	Fair	In Use
FIVCO	Calibrator	Teledyne-API T700	Good	In Use
FIVCO	O3 Monitor	Teledyne-API T400	Good	In Use
FIVCO	Datalogger	Agilaire 8872 Data Logger	Good	In Use
FIVCO	Meteorological- Probe	41372VC RH/Temp	Fair	In Use
FIVCO	NOx Monitor	Teledyne-API 200E	Good	In Use
FIVCO	PM2.5 Continuous	Teledyne API T640	Good	In Use
FIVCO	PM2.5 Sampler	Partisol Plus 2025 Sequential	Good	In Use
FIVCO	SO2 Monitor	Teledyne-API T100	Good	In Use
FIVCO	Zero Air Unit	Teledyne-API 701 Zero Air	Good	In Use
Franklin	Datalogger	ESC Model 8832	Fair	In Use
Franklin	Meteorological- Probe	41372VC RH/Temp	Fair	In Use
Franklin	Photometer	Teledyne-API 703E	Good	In Use
Franklin	Zero Air Unit	Teledyne-API 701 Zero Air	Good	In Use
Grayson Lake	Air Toxics- PAHs	PUF Air Sampler, Brushless	Good	In Use
Grayson Lake	Air Toxics- VOCs/Carbonyls	ATEC 2200-2, Dual Channel	Good	In Use
Grayson Lake	Datalogger	ESC Model 8832	Good	In Use
Grayson Lake	Meteorological- Pressure	Barometric Pressure 61202V	Fair	In Use
Grayson Lake	Meteorological- Probe	41372VC RH/Temp	Fair	In Use
Grayson Lake	O3 Monitor	Teledyne-API T400	Good	In Use
Grayson Lake	Photometer	Teledyne-API 703E	Good	In Use
Grayson Lake	PM10 Sampler	Partisol 2000	Good	In Use
Grayson Lake	PM10 Sampler	Partisol 2000	Good	In Use
Grayson Lake	PM2.5 Sampler	Partisol Plus 2025i Sequential	Good	In Use
Grayson Lake	Zero Air Unit	Teledyne-API 701 Zero Air	Good	In Use

Appendix J
KDAQ Equipment Inventory (Continued)

Location	Item	Description	Condition	Comments
Hazard	Datalogger	ESC Model 8832	Fair	In Use
Hazard	O3 Monitor	Teledyne-API 400E	Good	In Use
Hazard	PM2.5 Continuous	Thermo Scientific TEOM 1405	Good	In Use
Hazard	Zero Air Unit	Teledyne_API 701 Zero Air	Good	In Use
Hazard	PM2.5 Sampler	Partisol Plus 2025i Sequential	Good	In Use
Hazard	Photometer	Teledyne-API 703E	Good	In Use
Hopkinsville	Datalogger	ESC Model 8832	Fair	In Use
Hopkinsville	Photometer	Teledyne-API 703E	Good	In Use
Hopkinsville	PM2.5 Sampler	Partisol Plus 2025 Sequential	Good	In Use
Hopkinsville	Zero Air Unit	Teledyne-API 701 Zero Air	Good	In Use
Hopkinsville	O3 Monitor	Teledyne-API 400E	Good	In Use
JPRECC	Calibrator	Teledyne-API 700 E	Good	In Use
JPRECC	Datalogger	Agilaire 8872 Data Logger	Good	In Use
JPRECC	NOx Monitor	Teledyne-API 200E	Good	In Use
JPRECC	O3 Monitor	Teledyne-API T400	Fair	Backup/Spare
JPRECC	O3 Monitor	Teledyne-API T400	Good	In Use
JPRECC	PM10 Sampler	Partisol 2000	Good	In Use
JPRECC	PM2.5 Continuous	Teledyne API T640	Good	In Use
JPRECC	PM2.5 Sampler	Partisol Plus 2025 Sequential	Fair	In Use
JPRECC	SO2 Monitor	Teledyne-API T100	Good	In Use
Lewisport	Datalogger	ESC Model 8832	Fair	In Use
Lewisport	O3 Monitor	Teledyne-API T400	Good	In Use
Lewisport	Photometer	Teledyne-API 703E	Good	In Use
Lewisport	Zero Air Unit	Teledyne-API 701 Zero Air	Good	In Use
Lexington Primary	Calibrator	Teledyne-API 700 E	Good	In Use
Lexington Primary	Datalogger	ESC Model 8832	Good	In Use
Lexington Primary	NOx Monitor	Teledyne-API 200E	Good	In Use
Lexington Primary	O3 Monitor	Teledyne-API T400	Good	In Use
Lexington Primary	PM10 Sampler	Partisol 2000	Good	In Use
Lexington Primary	PM2.5 Continuous	Thermo Scientific TEOM 1405	Good	In Use
Lexington Primary	PM2.5 Sampler	Partisol Plus 2025 Sequential	Good	In Use
Lexington Primary	SO2 Monitor	Teledyne-API T100	Good	In Use
Lexington Primary	Zero Air Unit	Teledyne-API 701 Zero Air	Good	In Use
Lexington Primary	Zero Air Unit	Teledyne-API 701E Zero Air	Good	In Use
Middlesboro	Datalogger	ESC Model 8832	Good	In Use
Middlesboro	Meteorological- Probe	41372VC RH/Temp	Fair	In Use
Middlesboro	O3 Monitor	Teledyne-API T400	Good	In Use
Middlesboro	Photometer	Teledyne-API 703E	Good	In Use
Middlesboro	PM2.5 Sampler	Partisol Plus 2025i Sequential	Good	In Use
Middlesboro	Zero Air Unit	Teledyne-API 701 Zero Air	Good	In Use
Nicholasville	Calibrator	Teledyne-API 700 E	Fair	In Use
Nicholasville	Meteorological- Probe	Humidity and Temperature	Fair	In Use
Nicholasville	O3 Monitor	Teledyne-API T400	Good	In Use
Nicholasville	SO2 Monitor	Teledyne-API T100	Good	In Use
Nicholasville	Zero Air Unit	Teledyne-API 701 Zero Air	Good	In Use
Nicholasville	Datalogger	Agilaire 8872 Data Logger	Good	In Use
NKU	Calibrator	Teledyne-API T700	Good	In Use
NKU	Datalogger	Agilaire 8872 Data Logger	Good	In Use
NKU	NOx Monitor	Teledyne-API 200E	Good	In Use
NKU	O3 Monitor	Teledyne-API T400	Good	In Use
NKU	PM2.5 Continuous	Teledyne API T640	New	In Use
NKU	PM2.5 Sampler	Partisol Plus 2025 Sequential	Good	In Use
NKU	SO2 Monitor	Teledyne-API T104	Good	In Use
Owensboro Primary	Calibrator	Teledyne-API T700	Good	In Use
Owensboro Primary	Datalogger	Agilaire 8872 Data Logger	Good	In Use
Owensboro Primary	NOx Monitor	Teledyne-API 200E	Good	In Use
Owensboro Primary	O3 Monitor	Teledyne-API T400	Good	In Use

Appendix J
KDAQ Equipment Inventory (Continued)

Location	Item	Description	Condition	Comments
Owensboro Primary	PM2.5 Continuous	Teledyne API T640	Good	In Use
Owensboro Primary	PM2.5 Sampler	Partisol Plus 2025 Sequential	Good	In Use
Owensboro Primary	PM2.5 Sampler	Partisol Plus 2025i Sequential	Good	In Use
Owensboro Primary	SO2 Monitor	Teledyne-API T101	Good	In Use
Owensboro Primary	Zero Air Unit	Teledyne-API 701 Zero Air	Good	In Use
Paducah Regional Office	O3 Monitor	Teledyne-API T400	Good	Backup/Spare
Pikeville	Datalogger	Agilaire 8872 Data Logger	Fair	In Use
Pikeville	O3 Monitor	Teledyne-API T400	Good	In Use
Pikeville	Photometer	Teledyne-API 703E	Good	In Use
Pikeville	PM2.5 Continuous	Teledyne API T640	Good	In Use
Pikeville	PM2.5 Sampler	Partisol Plus 2025 Sequential	Good	In Use
Pikeville	Zero Air Unit	Teledyne-API 701E Zero Air	Good	In Use
Pikeville	PM2.5 Sampler	Partisol Plus 2025 Sequential	Good	Spare
Sebree	Datalogger	ESC Model 8832	Good	In Use
Sebree	SO2 Monitor	Teledyne-API T100	Good	In Use
Sebree	Zero Air Unit	Teledyne-API 701 Zero Air	Fair	In Use
Sebree	Calibrator	Teledyne-API 700 E	Good	In Use
Shepherdsville	Datalogger	Agilaire 8872 Data Logger	Fair	In Use
Shepherdsville	Photometer	Teledyne-API 703E	Good	In Use
Shepherdsville	Zero Air Unit	Teledyne-API 701 Zero Air	Fair	In Use
Smithland	Datalogger	ESC Model 8832	Good	In Use
Smithland	O3 Monitor	Teledyne-API T400	Good	In Use
Smithland	Photometer	Teledyne-API 703E	Good	In Use
Smithland	Zero Air Unit	Teledyne-API 701 Zero Air	Good	In Use
Smiths Grove	Datalogger	ESC Model 8832	Fair	In Use
Smiths Grove	O3 Monitor	Teledyne-API T400	Good	Backup/Spare
Smiths Grove	O3 Monitor	Teledyne-API T400	Good	In Use
Smiths Grove	Photometer	Teledyne-API 703E	Good	In Use
Smiths Grove	PM2.5 Continuous	Thermo Scientific TEOM 1405	Good	In Use
Smiths Grove	PM2.5 Sampler	Partisol Plus 2025i Sequential	Good	In Use
Smiths Grove	PM2.5 Sampler	Partisol Plus 2025 Sequential	Good	In Use
Smiths Grove	Zero Air Unit	Teledyne-API 701 Zero Air	Fair	In Use
Somerset	Datalogger	ESC Model 8832	Fair	In Use
Somerset	O3 Monitor	Teledyne-API T400	Good	In Use
Somerset	Photometer	Teledyne-API 703E	Good	In Use
Somerset	PM2.5 Sampler	Partisol Plus 2025i Sequential	Good	In Use
Somerset	Zero Air Unit	Teledyne-API 701 Zero Air	Good	In Use
TSB- Technical Support Shop	Air Toxics- VOCs	Xontech 911a	Good	Spare
TSB- Technical Support Shop	Air Toxics- VOCs/Carbonyls	ATEC 2200	Fair	Spare
TSB- Technical Support Shop	Air Toxics- VOCs/Carbonyls	ATEC 2200	Fair	Spare
TSB- Technical Support Shop	Air Toxics- VOCs/Carbonyls	ATEC 2200	Fair	Spare
TSB- Technical Support Shop	Air Toxics- VOCs/Carbonyls	ATEC 2200-2, Dual Channel	Good	Spare
TSB- Technical Support Shop	Air Toxics- VOCs/Carbonyls	ATEC 2200-2, Dual Channel	Good	Spare
TSB- Technical Support Shop	Air Toxics- VOCs/Carbonyls	ATEC 2200-2, Dual Channel	Fair	Spare
TSB- Technical Support Shop	Air Toxics- VOCs/Carbonyls	ATEC 2200-2, Dual Channel	Good	Spare
TSB- Technical Support Shop	Air Toxics- VOCs/Carbonyls	ATEC 2200-2, Dual Channel	Good	Spare
TSB- Technical Support Shop	Calibrator	Teledyne-API 700 E	Good	Spare
TSB- Technical Support Shop	Calibrator	Teledyne-API 700 E	Good	Spare
TSB- Technical Support Shop	Calibrator	Teledyne-API 700 E	Good	Spare
TSB- Technical Support Shop	Calibrator	Teledyne-API 700 E	Good	Spare
TSB- Technical Support Shop	Calibrator	Teledyne-API 700 E	Good	Spare
TSB- Technical Support Shop	Calibrator	Teledyne-API 700 E	Good	Spare
TSB- Technical Support Shop	Calibrator	Teledyne-API 700 E	Fair	Spare
TSB- Technical Support Shop	Calibrator	Teledyne-API T700	Good	Spare
TSB- Technical Support Shop	Calibrator	Teledyne-API T700	Good	Spare
TSB- Technical Support Shop	Calibrator	Teledyne-API T700	Good	Spare
TSB- Technical Support Shop	Calibrator	Teledyne-API T700	Good	Spare
TSB- Technical Support Shop	Calibrator	Teledyne-API T700	Good	Spare

Appendix J
KDAQ Equipment Inventory (Continued)

Location	Item	Description	Condition	Comments
TSB- Technical Support Shop	Datalogger	ESC Model 8832	Fair	Spare
TSB- Technical Support Shop	Datalogger	ESC Model 8832	Fair	Spare
TSB- Technical Support Shop	Datalogger	ESC Model 8832	Fair	Spare
TSB- Technical Support Shop	Datalogger	ESC Model 8832	Fair	Spare
TSB- Technical Support Shop	Datalogger	ESC Model 8832	Fair	Spare
TSB- Technical Support Shop	Datalogger	ESC Model 8832	Fair	Spare
TSB- Technical Support Shop	Datalogger	ESC Model 8832	Fair	Spare
TSB- Technical Support Shop	Datalogger	ESC Model 8832	Fair	Spare
TSB- Technical Support Shop	Datalogger	ESC Model 8832	Fair	Spare
TSB- Technical Support Shop	Datalogger	ESC Model 8832	Fair	Spare
TSB- Technical Support Shop	Datalogger	ESC Model 8832	Fair	Spare
TSB- Technical Support Shop	Datalogger	ESC Model 8832	Good	Spare
TSB- Technical Support Shop	Datalogger	ESC Model 8832	Fair	Spare
TSB- Technical Support Shop	Datalogger	ESC Model 8832	Fair	Spare
TSB- Technical Support Shop	Datalogger	ESC Model 8832	Fair	Spare
TSB- Technical Support Shop	Datalogger	ESC Model 8832	Fair	Spare
TSB- Technical Support Shop	Datalogger	ESC Model 8832	Good	Spare
TSB- Technical Support Shop	Datalogger	ESC Model 8832	Fair	Spare
TSB- Technical Support Shop	Datalogger	ESC Model 8832	Good	Spare
TSB- Technical Support Shop	Datalogger	ESC Model 8832	Fair	Spare
TSB- Technical Support Shop	Datalogger	ESC Model 8832	Good	Spare
TSB- Technical Support Shop	Datalogger	ESC Model 8832	Fair	Spare
TSB- Technical Support Shop	Datalogger	ESC Model 8832	Fair	Spare
TSB- Technical Support Shop	Datalogger	Agilaire Model 8872	Good	New
TSB- Technical Support Shop	Datalogger	Agilaire Model 8872	Good	New
TSB- Technical Support Shop	Datalogger	ESC Model 8832	Good	Spare
TSB- Technical Support Shop	Datalogger	ESC Model 8832	Good	Spare
TSB- Technical Support Shop	Datalogger	ESC Model 8832	Good	Spare
TSB- Technical Support Shop	Datalogger	ESC Model 8832	Good	Spare
TSB- Technical Support Shop	Datalogger	ESC Model 8832	Good	Spare
TSB- Technical Support Shop	Datalogger	ESC Model 8832	Good	Spare
TSB- Technical Support Shop	Datalogger	ESC Model 8832	Good	Spare
TSB- Technical Support Shop	Datalogger	ESC Model 8832	Good	Spare
TSB- Technical Support Shop	Lead Sampler- TSP	Tisch Model TE-5170DV-BL TSP	Good	Spare
TSB- Technical Support Shop	Lead Sampler- TSP	Tisch Model TE-5170DV-BL TSP	Good	Spare
TSB- Technical Support Shop	Lead Sampler- TSP	Tisch Model TE-5170DV-BL TSP	Good	Spare
TSB- Technical Support Shop	Lead Sampler- TSP	Tisch Model TE-5170DV-BL TSP	Good	Spare
TSB- Technical Support Shop	Meteorological- Pressure	Barometric Pressure 61202V	Fair	Spare
TSB- Technical Support Shop	Meteorological- Probe	Humidity and Temperature 41382VC	Fair	Spare
TSB- Technical Support Shop	Meteorological- Solar	Solar Radiation CMP4	Fair	Spare
TSB- Technical Support Shop	NOx Monitor	Teledyne-API 200E	Good	Spare
TSB- Technical Support Shop	NOx Monitor	Teledyne-API 200E	Fair	Spare
TSB- Technical Support Shop	NOx Monitor	Teledyne-API 200E	Fair	Spare
TSB- Technical Support Shop	NOx Monitor	Teledyne-API 200E	Fair	Spare
TSB- Technical Support Shop	NOx Monitor	Teledyne-API 200E	Fair	Spare
TSB- Technical Support Shop	NOx Monitor	Teledyne-API 200E	Fair	Spare
TSB- Technical Support Shop	NOx Monitor	Teledyne-API 200E	Fair	Spare
TSB- Technical Support Shop	NOx Monitor	Teledyne-API 200E	Fair	Spare
TSB- Technical Support Shop	NOx Monitor	Teledyne-API 200E	Fair	Spare
TSB- Technical Support Shop	O3 Monitor	Teledyne-API 400E	Fair	Spare
TSB- Technical Support Shop	O3 Monitor	Teledyne-API 400E	Fair	Spare
TSB- Technical Support Shop	O3 Monitor	Teledyne-API 400E	Fair	Spare
TSB- Technical Support Shop	O3 Monitor	Teledyne-API 400E	Fair	Spare
TSB- Technical Support Shop	O3 Monitor	Teledyne-API 400E	Fair	Spare
TSB- Technical Support Shop	O3 Monitor	Teledyne-API 400E	Fair	Spare
TSB- Technical Support Shop	O3 Monitor	Teledyne-API 400E	Fair	Spare
TSB- Technical Support Shop	O3 Monitor	Teledyne-API 400E	Fair	Spare
TSB- Technical Support Shop	O3 Monitor	Teledyne-API 400E	Fair	Spare
TSB- Technical Support Shop	O3 Monitor	Teledyne-API 400E	Fair	Spare

Appendix J
KDAQ Equipment Inventory (Continued)

Location	Item	Description	Condition	Comments
TSB- Technical Support Shop	O3 Monitor	Teledyne-API T400	Good	Spare
TSB- Technical Support Shop	O3 Monitor	Teledyne-API T400	Good	Spare
TSB- Technical Support Shop	O3 Monitor	Teledyne-API T400	Good	Spare
TSB- Technical Support Shop	O3 Monitor	Teledyne-API T400	Good	Spare
TSB- Technical Support Shop	O3 Monitor	Teledyne-API T400	Good	Spare
TSB- Technical Support Shop	O3 Monitor	Teledyne-API T400	Good	Spare
TSB- Technical Support Shop	O3 Monitor	Teledyne-API T400	Good	Spare
TSB- Technical Support Shop	O3 Monitor	Teledyne-API T400	Good	Spare
TSB- Technical Support Shop	O3 Monitor	Teledyne-API T400	Good	Spare
TSB- Technical Support Shop	O3 Monitor	Teledyne-API T400	Good	Spare
TSB- Technical Support Shop	Photometer	Teledyne-API 703E	Good	Spare
TSB- Technical Support Shop	Photometer	Teledyne-API 703E	Good	Spare
TSB- Technical Support Shop	PM10 Sampler	Partisol 2000	Poor	Spare
TSB- Technical Support Shop	PM10 Sampler	Partisol 2000	Poor	Spare
TSB- Technical Support Shop	PM10 Sampler	Partisol 2000	Good	Spare
TSB- Technical Support Shop	PM10 Sampler	Partisol 2000	Good	Spare
TSB- Technical Support Shop	PM10 Sampler	Partisol 2000	Good	Spare
TSB- Technical Support Shop	PM10 Sampler	Partisol 2000	Good	Spare
TSB- Technical Support Shop	PM10 Sampler	Partisol 2000	Good	Spare
TSB- Technical Support Shop	PM10 Sampler	Partisol 2000	Good	Spare
TSB- Technical Support Shop	PM10 Sampler	Partisol 2000	Good	Spare
TSB- Technical Support Shop	PM2.5 Continuous	Thermo Scientific TEOM 1405	New	Spare
TSB- Technical Support Shop	PM2.5 Continuous	Thermo Scientific TEOM 1405	New	Spare
TSB- Technical Support Shop	PM2.5 Continuous	Thermo Scientific TEOM 1405	Good	Spare
TSB- Technical Support Shop	PM2.5 Continuous	Thermo Scientific TEOM 1400	Good	Spare
TSB- Technical Support Shop	PM2.5 Continuous	Thermo Scientific TEOM 1400	Good	Spare
TSB- Technical Support Shop	PM2.5 Continuous	Thermo Scientific TEOM 1400	Good	Spare
TSB- Technical Support Shop	PM2.5 Continuous	Thermo Scientific TEOM 1400	Good	Spare
TSB- Technical Support Shop	PM2.5 Continuous	Thermo Scientific TEOM 1400	Good	Spare
TSB- Technical Support Shop	PM2.5 Continuous	Thermo Scientific TEOM 1400	Good	Spare
TSB- Technical Support Shop	PM2.5 Continuous	Thermo Scientific TEOM 1400	Good	Spare
TSB- Technical Support Shop	PM2.5 Continuous	Thermo Scientific TEOM 1400	Good	Spare
TSB- Technical Support Shop	PM2.5 Continuous	Thermo Scientific TEOM 1405	Good	Spare
TSB- Technical Support Shop	PM2.5 Continuous	Thermo Scientific TEOM 1405	Good	Spare
TSB- Technical Support Shop	PM2.5 Sampler	Partisol Plus 2025i Sequential	Good	Spare
TSB- Technical Support Shop	PM2.5 Sampler	Partisol Plus 2025 Sequential	Good	Spare
TSB- Technical Support Shop	PM2.5 Sampler	Partisol Plus 2025 Sequential	Good	Spare
TSB- Technical Support Shop	PM2.5 Sampler	Partisol Plus 2025 Sequential	Good	Spare
TSB- Technical Support Shop	PM2.5 Sampler	Partisol Plus 2025i Sequential	Good	Spare
TSB- Technical Support Shop	PM2.5 Sampler	Partisol Plus 2025 Sequential	Good	Spare
TSB- Technical Support Shop	PM2.5 Sampler	Partisol Plus 2025 Sequential	Good	Spare
TSB- Technical Support Shop	PM2.5 Sampler	Partisol Plus 2025 Sequential	Good	Spare
TSB- Technical Support Shop	PM2.5 Sampler	Partisol Plus 2025 Sequential	Good	Spare
TSB- Technical Support Shop	PM2.5 Sampler	Partisol Plus 2025 Sequential	Good	Spare
TSB- Technical Support Shop	PM2.5 Sampler	Partisol Plus 2025 Sequential	Good	Spare
TSB- Technical Support Shop	PM2.5 Sampler	Partisol Plus 2025 Sequential	Good	Spare
TSB- Technical Support Shop	PM2.5 Sampler	Partisol Plus 2025 Sequential	Good	Spare
TSB- Technical Support Shop	PM2.5 Sampler	Partisol Plus 2025 Sequential	Good	Spare
TSB- Technical Support Shop	PM2.5 Sampler	Partisol Plus 2025 Sequential	Good	Spare
TSB- Technical Support Shop	PM2.5 Sampler	Partisol Plus 2025i Sequential	Good	Spare
TSB- Technical Support Shop	SO2 Monitor	Teledyne-API 100E	Fair	Spare
TSB- Technical Support Shop	SO2 Monitor	Teledyne-API 100E	Fair	Spare
TSB- Technical Support Shop	SO2 Monitor	Teledyne-API 100E	Fair	Spare
TSB- Technical Support Shop	SO2 Monitor	Teledyne-API 100E	Fair	Spare
TSB- Technical Support Shop	SO2 Monitor	Teledyne-API 100E	Fair	Spare
TSB- Technical Support Shop	SO2 Monitor	Teledyne-API T100	Good	Spare
TSB- Technical Support Shop	SO2 Monitor	Teledyne-API T100	Good	Spare
TSB- Technical Support Shop	SO2 Monitor	Teledyne-API T100	Good	Spare
TSB- Technical Support Shop	SO2 Monitor	Teledyne-API T100	Good	Spare
TSB- Technical Support Shop	SO2 Monitor	Teledyne-API T100	Good	Spare
TSB- Technical Support Shop	SO2 Monitor	Teledyne-API T100	Good	Spare

Appendix J
KDAQ Equipment Inventory (Continued)

Location	Item	Description	Condition	Comments
TSB- Technical Support Shop	Zero Air Unit	Teledyne-API 701 Zero Air	Good	Spare
TSB- Technical Support Shop	Zero Air Unit	Teledyne-API 701 Zero Air	Good	Spare
TSB- Technical Support Shop	Zero Air Unit	Teledyne-API 701 Zero Air	Good	Spare
TSB- Technical Support Shop	Zero Air Unit	Teledyne-API 701E Zero Air	Good	Spare
TSB- Technical Support Shop	Zero Air Unit	Teledyne-API 701 Zero Air	Good	Spare
TSB- Technical Support Shop	Zero Air Unit	Teledyne-API 701 Zero Air	Good	Spare
TSB- Technical Support Shop	Zero Air Unit	Teledyne-API 701 Zero Air	Fair	Spare
TSB- Technical Support Shop	Zero Air Unit	Teledyne-API 701 Zero Air	Fair	Spare
TSB- Technical Support Shop	Zero Air Unit	Teledyne-API 701 Zero Air	Fair	Spare
TSB- Technical Support Shop	Zero Air Unit	Teledyne-API 701 Zero Air	Fair	Spare
TSB- Technical Support Shop	Zero Air Unit	Teledyne-API 701 Zero Air	Fair	Spare
TSB-Quality Assurance Shop	Audit Calibrator	Environics 6103	Fair	In Use
TSB-Quality Assurance Shop	Audit Calibrator	Environics 6100	Fair	In Use
TSB-Quality Assurance Shop	Audit Calibrator	Environics 6100	Fair	In Use
TSB-Quality Assurance Shop	Audit Calibrator	Environics 6103	Fair	In Use
TSB-Quality Assurance Shop	Audit Calibrator	Environics Multigas & Ozone Transfer Std	Good	In Use
TSB-Quality Assurance Shop	Audit Calibrator	Environics Multigas & Ozone Transfer Std	Good	In Use
TSB-Quality Assurance Shop	Audit Calibrator	Environics Multigas & Ozone Transfer Std	Good	In Use
TSB-Quality Assurance Shop	Audit Calibrator	Environics Multigas & Ozone Transfer Std	Good	In Use
TSB-Quality Assurance Shop	Zero Air Unit	Teledyne-API Model 751H Zero Air	Good	In Use
TSB-Quality Assurance Shop	Zero Air Unit	Teledyne-API Model 751H Zero Air	Good	In Use
TSB-Quality Assurance Shop	Zero Air Unit	Teledyne-API Model 751H Zero Air	Good	In Use
TSB-Quality Assurance Shop	Zero Air Unit	Teledyne-API Model S7000 Zero Air	Fair	In Use
TSB-Quality Assurance Shop	Zero Air Unit	Teledyne-API Model S7000 Zero Air	Fair	In Use
TSB-Quality Assurance Shop	Zero Air Unit	Teledyne-API Model 751H Zero Air	Good	In Use
TVA	Air Toxics- VOCs	Xontech 911a	Good	In Use
TVA	Air Toxics- VOCs	Xontech 911a	Good	In Use
Worthington	Calibrator	Teledyne-API 700 E	Good	In Use
Worthington	Datalogger	Agilaire 8872 Data Logger	Fair	In Use
Worthington	O3 Monitor	Teledyne-API T400	Good	In Use
Worthington	SO2 Monitor	Teledyne-API T100	Good	In Use
Worthington	Zero Air Unit	Teledyne-API 701E Zero Air	Good	In Use

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APPENDIX K

PUBLIC COMMENTS

KENTUCKY DIVISION FOR AIR QUALITY
AMBIENT AIR MONITORING NETWORK
Comments Received 6/25/2018

Energy and Environment Cabinet
Department for Environmental Protection
Division for Air Quality

A public comment period on the KENTUCKY DIVISION FOR AIR QUALITY AMBIENT AIR MONITORING NETWORK PLAN 2018 was held from May 24, 2018 through June 23, 2018.

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KDAQ AIR MONITORING STATIONS
BY
REGIONAL OFFICE

2018 KDAQ MONITORING STATIONS BY REGIONAL OFFICE

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UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
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OCT 2 3 2018

Mr. Sean Alteri
Director
Kentucky Division for Air Quality
Department for Environmental Protection
300 Sower Boulevard, Floor 2
Frankfort, Kentucky 40601-6571

Dear Mr. Alteri:

Thank you for submitting the 2018 annual ambient air monitoring network plan (Network Plan) for the Commonwealth of Kentucky, dated June 28, 2018. The Network Plan covers Kentucky's ambient air monitoring network, which is comprised of assets and resources managed by the Kentucky Division for Air Quality (KDAQ) and the Louisville Metro Air Pollution Control District (LMAPCD). The Network Plan is required by 40 Code of Federal Regulations (CFR) §58.10.

The U.S. Environmental Protection Agency understands that the KDAQ provided a 30-day public comment for the Network Plan and received no comments. The EPA has reviewed the Network Plan provided by the KDAQ.

On February 1, 2018, the EPA approved the installation of a state and local air monitoring station (SLAMS) sulfur dioxide (SO_2) monitor to represent maximum concentrations in the southwestern portion of Jefferson County. This site is being established as part of an Agreed Board Order between the LMAPCD and Kosmos Cement Company. The installation has since been delayed due to issues regarding property access. The EPA appreciates that the LMAPCD and Kosmos Cement Company are making progress to resolve these issues and anticipates that the site will be installed in early 2019.

Effective June 1, 2019, the LMAPCD is required to have PAMS equipment implemented at the Cannons Lane National Core (NCore) site (AQS ID: 21-111-0067). To meet these requirements, the LMAPCD intends to install an auto GC, a ceilometer and a barometric pressure sensor by June 1, 2019. In addition, a new shelter will be installed to accommodate the new equipment. However, the LMAPCD, due to current funding limitations, does not believe the required ultraviolet pyranometer and carbonyls sampler will be installed until June 1, 2020. The EPA understands the LMAPCD's concerns and will work to get the required funding to the agency as soon as possible.

With this letter, the EPA approves the Kentucky Network Plan. We have enclosed comments on the Network Plan and details of the review. Thank you for working with the EPA to monitor air pollution and promote healthy air quality in Kentucky. If you have any questions or concerns, please contact Gregg Worley at (404) 562-9141 or Mike Moeller at (404) 562-8985.

Sincerely,

Carol L. Kemker for

Beverly H. Banister
Director
Air, Pesticides and Toxics Management Division

Enclosure

cc: Mr. Keith Talley
Director, Louisville Metro Air Pollution Control District

CY 2018 Commonwealth of Kentucky Ambient Air Monitoring Network Plan
U.S. EPA Region 4 Comments and Recommendations

This document contains U.S. Environmental Protection Agency comments and recommendations on the Commonwealth of Kentucky's 2018 Ambient Air Monitoring Network Plan (Network Plan). Ambient air monitoring rules, which include regulatory requirements that address network plans, data certification, and minimum monitoring requirements, among other requirements, are found in 40 CFR Part 58. Minimum monitoring requirements for criteria pollutants are listed in 40 CFR Part 58, Appendix D. Minimum monitoring requirements are listed for ozone (O_3), particulate matter less than 2.5 microns ($PM_{2.5}$), particulate matter less than 10 microns (PM_{10}), nitrogen dioxide (NO_2), sulfur dioxide (SO_2), carbon monoxide (CO), and lead (Pb).

The minimum monitoring requirements are based on core based statistical area (CBSA) boundaries as defined by the U.S. Office of Management and Budget (OMB), July 1, 2017, population estimates from the U.S. Census Bureau, and historical ambient air monitoring data. Minimum monitoring requirements for O_3, $PM_{2.5}$, and PM_{10} only apply to metropolitan statistical areas (MSAs), which are a subset of CBSAs. OMB currently defines 26 CBSAs in the Commonwealth of Kentucky. These CBSAs and the respective July 1, 2017, population estimates from the U.S. Census Bureau are shown in Table 1.

Table 1: Core Based Statistical Areas and July 1, 2017 Population Estimates

CBSA Name	CBSA Type	Population
Cincinnati, OH-KY-IN	Metropolitan Statistical Area	2,179,082
Louisville/Jefferson County, KY-IN	Metropolitan Statistical Area	1,293,953
Lexington-Fayette, KY	Metropolitan Statistical Area	512,650
Huntington-Ashland, WV-KY-OH	Metropolitan Statistical Area	356,474
Evansville, IN-KY	Metropolitan Statistical Area	315,669
Clarksville, TN-KY	Metropolitan Statistical Area	285,042
Bowling Green, KY	Metropolitan Statistical Area	174,835
Elizabethtown-Fort Knox, KY	Metropolitan Statistical Area	150,430
London, KY	Micropolitan Statistical Area	127,615
Owensboro, KY	Metropolitan Statistical Area	118,376
Richmond-Berea, KY	Micropolitan Statistical Area	107,924
Paducah, KY-IL	Micropolitan Statistical Area	97,037
Frankfort, KY	Micropolitan Statistical Area	73,029
Somerset, KY	Micropolitan Statistical Area	64,449
Danville, KY	Micropolitan Statistical Area	54,380
Glasgow, KY	Micropolitan Statistical Area	53,908
Mount Sterling, KY	Micropolitan Statistical Area	46,761
Bardstown, KY	Micropolitan Statistical Area	45,640
Madisonville, KY	Micropolitan Statistical Area	45,547
Murray, KY	Micropolitan Statistical Area	38,919
Mayfield, KY	Micropolitan Statistical Area	37,121
Union City, TN-KY	Micropolitan Statistical Area	36,577
Central City, KY	Micropolitan Statistical Area	30,816
Middlesborough, KY	Micropolitan Statistical Area	26,894
Campbellsville, KY	Micropolitan Statistical Area	25,472
Maysville, KY	Micropolitan Statistical Area	17,174

Monitoring Network Changes

The Kentucky Division for Air Quality (KDAQ) and the Louisville Metro Air Pollution Control District (LMAPCD) have requested to make the following changes to the Kentucky network (Table 2).

Table 2: Proposed Changes in Monitoring

CBSA	AQS ID	Site Name	Pollutant	Type	Comments
Huntington-Ashland, WV-KY-OH	21-019-0017	Ashland Primary	VOC	SPM	Acknowledged: Permanently discontinue special-purpose VOC sampling. Effective December 31, 2018.
Louisville-Jefferson County, KY-IN	21-111-0051	Watson Lane	PM_{10} $PM_{2.5}$	SLAMS	Approved: The LMAPCD is evaluating the API Teledyne T640 particulate analyzer. If the API T640 evaluation is successful, the analyzer will replace the existing $PM_{2.5}$ BAM 1020. In addition, the PM_{10} BAM 1020 analyzer will be removed. Effective Q1 2019.
Louisville-Jefferson County, KY-IN	21-111-1041	Firearms Training	PM_{10} $PM_{2.5}$	SLAMS	Approved: The LMAPCD is evaluating the API Teledyne T640 particulate analyzer. If the API T640x evaluation is successful, the analyzer will replace the existing $PM_{2.5}$ and PM_{10} BAM 1020 instruments Additionally, the LMAPCD will remove the $PM_{2.5}$ FRM 2025i primary and collocated samplers. The collocated sampler will be installed at the Cannons Lane site. Effective Q1 2019.
Louisville-Jefferson County, KY-IN	21-111-0067	Cannons Lane	PM_{10} $PM_{2.5}$ PM_{coarse}	SLAMS	Acknowledged: The LMAPCD is evaluating the API Teledyne T640 particulate analyzer. If the API T640x evaluation is successful, the analyzer will replace the existing $PM_{2.5}$, PM_{10}, PM_{coarse} BAM 1020 instruments. Additionally, the LMAPCD will install a $PM_{2.5}$ FRM 2025i collocated sampler for $PM_{2.5}$ FRM collocation. Effective Q1 2019.
Louisville-Jefferson County, KY-IN	21-111-0080	Carrithers Middle School	$PM_{2.5}$	SPM	Acknowledged: The LMAPCD is evaluating the API Teledyne T640 particulate analyzer. If the API T640 evaluation is successful, the analyzer will replace the existing $PM_{2.5}$ BAM 1020 instrument. Upon installation of the API T640, the $PM_{2.5}$ monitor will remain a SPM and the LMAPCD requests that the $PM_{2.5}$ data not be subject to the $PM_{2.5}$ NAAQS. For EPA to grant this, the LMAPCD must enter NAAQS exclusion flags in AQS for these samplers. Effective Q1 2019.

Louisville-Jefferson County, KY-IN	21-111-0075	Durrett Lane	$PM_{2.5}$	SPM	Acknowledged: Install the API T640 analyzer as an SPM to evaluate against the existing $PM_{2.5}$ FRM 2025i sampler. The API T640 $PM_{2.5}$ SPM would be in place for one year with the $PM_{2.5}$ FRM to assess optical measurement in the near-road environment. The LMAPCD requests that the $PM_{2.5}$ data not be subject to the $PM_{2.5}$ NAAQS. For EPA to grant this, the LMAPCD must enter NAAQS exclusion in AQS for these samplers. Effective Q1 2019.
Louisville-Jefferson County, KY-IN	21-111-0067	Cannons Lane	PAMS	NCore	Acknowledged: To meet the PAMS requirements, the LMAPCD intends to install an auto GC, a ceilometer and a barometric pressure sensor by June 1, 2019. In addition, a new shelter will be installed to accommodate the new equipment. However, due to current funding limitations, the requirements for the ultraviolet pyranometer and carbonyls sampler will not be installed until June 1, 2020.
Louisville-Jefferson County, KY-IN	21-111-0065	Kosmosdale	SO_2	SLAMS	Acknowledged: On February 1, 2018, the EPA approved the installation of a SLAMS SO_2 monitor to represent maximum concentrations in the southwestern portion of Jefferson County established as part of an Agreed Board Order between the LMAPCD and Kosmos Cement Company. The installation has been delayed due to property access issues. The EPA understands that the LMAPCD and Kosmos Cement Company are making progress in resolving these issues and that the monitor will be installed in 2019.

The EPA reviewed the requests for monitor discontinuation and determined that they met the requirements of 40 CFR §58.14(c) for monitor discontinuation. The minimum monitoring requirements found in 40 CFR Part 58, Appendix D will continue to be met for the respective MSAs after the approved monitors are discontinued.

The LMAPCD is requesting that the API T640 $PM_{2.5}$ analyzers at the Durrett Lane and Carrithers Middle School sites remain SPMs and not be subject to the $PM_{2.5}$ NAAQS. For the EPA to grant this, the LMAPCD must enter NAAQS exclusion flags in AQS for these samplers.

The KDAQ is discontinuing volatile organic compound (VOC) sampling at the Ashland Primary site (AQS ID: 21-019-0017) effective December 31, 2018. This sampling is not required by 40 CFR Part 58. VOC concentrations have been consistently low and comparable to observations at National Air Toxics Trends Stations (NATTS). The EPA acknowledges that the KDAQ has stopped VOC sampling at the site and has no plans to restart sampling in the future.

Operating Schedules
40 CFR § 58.12

The monitoring network proposed in the Network Plan meets the required operating schedules for all continuous analyzers and all manual Pb, PM_{10}, $PM_{2.5}$, and $PM_{2.5}$ Speciation Trends Network (STN) monitors. Neither the KDAQ nor the LMAPCD proposes any changes to the operating schedules.

Air Quality Index (AQI) Reporting
40 CFR §58.50

AQI reporting is required in MSAs with populations over 350,000 as of the last U.S. Census. Four MSAs in the Commonwealth of Kentucky meet this criterion: Cincinnati, OH-KY-IN; Louisville/Jefferson County, KY-IN; Lexington-Fayette, KY; and Huntington-Ashland, WV-KY-OH. The AQI is being reported in each of these MSAs. The KDAQ and the LMAPCD are meeting this requirement.

National Core (NCore) Monitoring Network
40 CFR Part 58, Appendix D, Section 3.0

Each state is required to operate at least one NCore site. The NCore site must measure, at a minimum, $PM_{2.5}$ particle mass using continuous and integrated/filter-based samplers, speciated $PM_{2.5}$, $PM_{10-2.5}$ particle mass, O_3, SO_2, CO, NO/NOy, wind speed, wind direction, relative humidity, and ambient temperature. The LMAPCD operates the required NCore site at Cannons Lane (AQS ID: 21-111-0067). The 2018 Network Plan meets the minimum monitoring requirements for the NCore site.

O_3 Monitoring Requirements
40 CFR Part 58, Appendix D, Section 4.1 and Table D-2

Neither the KDAQ or the LMAPCD have made any changes to the O_3 network since the last Network Plan. The network described in the 2018 Network Plan meets the minimum O_3 monitoring requirements specified by 40 CFR Part 58, Appendix D, Table D-2.

CO Monitoring Requirements
40 CFR Part 58, Appendix D, Section 4.2

Ambient air monitoring network design criteria for CO are found in Section 4.2 of Appendix D to 40 CFR Part 58. CBSAs with populations over one million are required to operate one CO monitor collocated with a near-road NO_2 monitor by January 1, 2017 as indicated in 40 CFR §58.13(e)(2). This requirement is already being met for the Cincinnati, OH-KY-IN CBSA through a memorandum of agreement (MOA) with Ohio. The near-road site (AQS ID: 39-061-0048) is located in Ohio and is operated by the Southwest Ohio Air Quality Agency (SWOAQA). This requirement is also being met for the Louisville/Jefferson County, KY-IN CBSA by the CO monitor operating at the Durrett Lane near-road site (AQS ID: 21-111-0075).

The proposed CO monitoring network described in the Network Plan meets all the design criteria of 40 CFR Part 58.

NO_2 Monitoring Requirements
40 CFR Part 58, Appendix D, Section 4.3

Ambient air monitoring network design criteria for NO_2 are found in 40 CFR Part 58, Appendix D, Section 4.3. Three types of NO_2 monitoring are required: near-road, area-wide, and Regional Administrator. These types of NO_2 monitoring are described in Sections 4.3.2, 4.3.3, and 4.3.4, respectively.

Ambient air monitoring design criteria for near-road NO_2 monitoring sites are found in 40 CFR Part 58, Appendix D, Section 4.3.2. The LMAPCD operates a near-road NO_2 monitor in the Louisville/Jefferson County, KY-IN CBSA at the Durrett Lane monitoring site (AQS ID: 21-111-0075) and the SWOAQA operates a near-road NO_2 monitor in Ohio (AQS ID: 39-061-0048) for the Cincinnati, OH-KY-IN CBSA.

Ambient air monitoring network design criteria for area-wide NO_2 sites are found in 40 CFR Part 58, Appendix D, Section 4.3.3. Any CBSA with a population of 1,000,000 or more persons is required to monitor a location of expected highest NO_2 concentration representing the neighborhood or larger spatial scales. The Cannons Lane NO_2 monitor (AQS ID: 21-111-0067) is used to meet the area-wide NO_2 monitoring requirement for the Louisville/Jefferson County, KY-IN CBSA. And the Northern Kentucky University NO_2 monitor (AQS ID: 21-037-3002) is used to meet the area-wide NO_2 monitoring requirement for the Cincinnati, OH-KY-IN CBSA. Please indicate in the 2019 Network Plan that both monitors are being used to fulfill the area-wide NO_2 requirement.

Ambient air monitoring network design criteria for Regional Administrator required NO_2 monitoring, often referred to as RA-40 monitoring, are found in Section 4.3.4 of Appendix D to 40 CFR Part 58. Under these provisions Regional Administrators must require a minimum of 40 NO_2 monitoring stations nationwide, with a primary focus on siting these monitors in locations to protect susceptible and vulnerable populations. The EPA has previously designated the Lexington Primary NO_2 monitor (AQS ID: 21-067-0012) as a RA-40 NO_2 monitoring site. The full list of NO_2 monitors identified by the Regional Administrators can be found on the EPA's website at http://www3.epa.gov/ttnamti1/svpop.html.

SO_2 Monitoring Requirements
40 CFR Part 58, Appendix D, Section 4.4

Ambient air monitoring network design criteria for SO_2 are found in 40 CFR Part 58, Appendix D, Section 4.4. This section requires that "The population weighted emissions index (PWEI) shall be calculated by states for each core based statistical area (CBSA)…" As a result, the SO_2 monitoring site(s) required in each CBSA will satisfy minimum monitoring requirements if the monitor(s) is sited within the boundaries of the parent CBSA and is/are of the following site types: population exposure, maximum concentration, source-oriented, general background, or regional transport. SO_2 monitors at NCore stations may satisfy minimum monitoring requirements if the monitors are located within CBSAs with minimally required monitors consistent with 40 CFR Part 58, Appendix D, Section 4.4. The SO_2 monitoring network design outlined in the Network Plan meets the minimum SO_2 PWEI requirements of 40 CFR Part 58. The Cincinnati, OH-KY-IN CBSA is required to have a minimum of two SO_2 monitors; there are currently six in operation, one of which is operated by the KDAQ. The Evansville, IN-KY; Huntington-Ashland, WV-KY-OH and Lexington-Jefferson County, KY-IN CBSAs are all required to have at least one SO_2 monitor. The KDAQ meets the requirement for the Evansville, IN-KY;

Huntington-Ashland, WV-KY-OH and Lexington-Jefferson County, KY-IN CBSAs. The LMAPCD meets the requirement for the Lexington-Jefferson County, KY-IN CBSA.

The LMAPCD has entered an Agreed Board Order (ABO) with Kosmos Cement Company to establish an SO_2 monitoring site to help characterize the ambient air quality in the Jefferson County SO_2 nonattainment area located in the southwestern portion of Jefferson County. The proposed site, Kosmosdale (AQS ID: 21-111-0065), will be operated as a SLAMS monitor and is intended to represent maximum concentrations of SO_2 in the area. The proposed site location was selected by the LMAPCD based on air quality dispersion modeling and was approved by the EPA on February 1, 2018. However, the installation has been delayed until 2019 due to property access issues. The EPA appreciates the progress that LMAPCD and Kosmos Cement Company are making to resolve these issues and anticipates that the site will be installed in early 2019.

Pb Monitoring Requirements
40 CFR Part 58, Appendix D, Section 4.5

The monitoring requirements for Pb are found in 40 CFR Part 58, Appendix D, Section 4.5. The emissions threshold for facilities near which source-oriented Pb monitoring is required is 0.5 tons per year (tpy). Monitoring is ongoing as required near the Enersys Inc. facility in Madison County at the Eastern Kentucky University (EKU) site (AQS ID: 21-151-0005).

Based on the 2015 network assessment, Pb monitoring is required near the AK Steel West Works facility in Boyd County. Monitoring is not currently ongoing at the AK Steel West Works facility. According to the KDAQ, on October 16, 2015, AK Steel issued a notice stating that the company planned to temporarily idle the blast furnace. The facility currently is in idle or shutdown mode. If the facility resumes operations, the KDAQ will need to identify a candidate site for Pb monitoring and submit a site proposal to the EPA for approval. The site proposal package must include all of the required information for proposed sites under 40 CFR §58.10(b). It should also include the KDAQ's rationale for the location of the proposed site, including supporting information such as site photos, maps, wind roses, etc.

PM_{10} Monitoring Requirements
40 CFR Part 58, Appendix A, Section 3.3
40 CFR Part 58, Appendix D, Section 4.6 and Table D-4

The Commonwealth of Kentucky's current PM_{10} primary monitoring network meets the minimum requirements found in 40 CFR Part 58, Appendix D, Table D-4 for all MSAs.

The LMAPCD is currently evaluating the API Teledyne T640 particulate analyzer. The API T640 is operating alongside a Met One BAM 1020 PM_{10} and $PM_{2.5}$ instrument, as well as collocated FRM Partisol 2025i instruments. If the evaluation of the API T640 analyzer proves successful operationally, and in data comparability, the LMAPCD intends to replace all BAM 1020s with API T640s in the first quarter of 2019. Specifically, the LMAPCD proposes to replace the BAM 1020 PM_{10} at the Cannons Lane (AQS ID: 21-111-0067) and Firearms Training (AQS ID: 21-111-1041) sites. In addition, the LMAPCD intends to shut down the BAM 1020 PM_{10} at the Watson Lane site (AQS ID: 21-111-0051). After this shutdown, the Louisville/Jefferson County, KY-IN CBSA will be down to three PM_{10} monitors; two operated by the LMACPD, at the Cannons Lane and Firearms Training sites, and one operated by the Indiana Department of Environmental Management, at the Jefferson PFAU site (AQS

ID: 18-019-0006). Based on current population and monitoring data, the minimum monitoring requirement for the Louisville/Jefferson County, KY-IN CBSA is two PM_{10} monitors. The EPA approves this monitor replacement and shutdown on the condition that all siting criteria are met.

All PM_{10} collocation requirements for manual methods found in 40 CFR Part 58, Appendix A, Section 3.3 are currently being met. Fifteen percent of each network of manual PM_{10} methods (at least one site) must be collocated. These collocation requirements are assessed at the primary quality assurance organization (PQAO) level. The LMAPCD only operates continuous PM_{10} samplers and thus does not have a collocation requirement. The PM_{10} monitor at 21st & Greenup (AQS ID: 21-019-0002) in the Huntington-Ashland, WV-KY-OH MSA is collocated. Additionally, the PM_{10} monitor at Grayson Lake (AQS ID: 21-043-0500) is collocated. This network meets the collocation requirement for the KDAQ.

$PM_{2.5}$ Monitoring Requirements
40 CFR Part 58, Appendix A, Section 3.2
40 CFR Part 58, Appendix D, Section 4.7 and Table D-5

The Commonwealth of Kentucky's current $PM_{2.5}$ monitoring network meets the minimum requirements found in 40 CFR Part 58, Appendix D, Table D-5 for all MSAs.

As discussed in the previous section, the LMAPCD is evaluating the API Teledyne T640 particulate analyzer. If the evaluation proves efficacious, the LMAPCD intends to replace all BAM 1020s with API T640s in the first quarter of 2019. Specifically, the LMAPCD proposes to replace the BAM 1020 $PM_{2.5}$ analyzers with API T640s at the Watson Lane (AQS ID: 21-111-0051), Firearms Training (AQS ID: 21-111-1041), Cannons Lane (AQS ID: 21-111-0067) and Carrithers Middle School (AQS ID: 21-111-0080) sites. The LMAPCD also intends to install the API T640 analyzer as an SPM at the Durrett Lane (AQS ID: 21-111-0075) near-road monitoring site to evaluate it against the existing $PM_{2.5}$ FRM 2025i sampler. The API T640 $PM_{2.5}$ SPM would be in place for one year to assess optical measurements in the near-road environment. The LMAPCD is requesting that the API T640 $PM_{2.5}$ analyzers at the Durrett Lane and Carrithers Middle School sites remain SPMs and not be subject to the $PM_{2.5}$ NAAQS. For the EPA to grant this, the LMAPCD must enter a NAAQS exclusion flag in AQS for these samplers. In addition, the LMAPCD intends to remove the $PM_{2.5}$ FRM 2025i primary and collocated samplers at the Firearms Training site. The collocated $PM_{2.5}$ FRM 2025i sampler will be installed at Cannons Lane. The EPA approves the monitor relocation to Cannons Lane as long as all siting criteria are met as outlined in the CFR. The EPA also approves the shutdown of the two collocated samplers at the Firearms Training site.

Manual $PM_{2.5}$ collocation requirements are found in 40 CFR Part 58, Appendix A, Section 3.2. These include the requirement that fifteen percent of each network of manual reference and equivalent methods (at least one site) be collocated. These collocation requirements are assessed at the PQAO level. The manual collocation requirements for $PM_{2.5}$ are currently being met in the Network Plan.

$PM_{2.5}$ Near-Road Monitoring Requirements
40 CFR Part 58, Appendix D, Section 4.7.1(b)(2)

Regulatory requirements in 40 CFR Part 58, Appendix D, Section 4.7.1(b)(2) require that "For CBSAs with a population of 1,000,000 or more persons, at least one $PM_{2.5}$ monitor is to be collocated at a near-road NO_2 station..." $PM_{2.5}$ near-road monitoring is required in the Cincinnati, OH-KY-IN CBSA and the Louisville/Jefferson County, KY-IN CBSA. The KDAQ has a MOA with Ohio to share the requirements for the Cincinnati, OH-KY-IN CBSA. The near-road site (AQS ID: 39-061-0048) is located in Ohio and is operated by the SWOAQA. This requirement is being met for the Louisville/Jefferson County, KY-IN CBSA by the Durrett Lane Near-Road Site (AQS ID: 21-111-0075).

$PM_{2.5}$ Continuous Monitoring Requirements
40 CFR Part 58, Appendix D, Section 4.7.2

Regulatory requirements for continuous $PM_{2.5}$ monitoring require that "...State, or where appropriate, local agencies must operate continuous $PM_{2.5}$ analyzers equal to at least one-half (round up) the minimum required sites listed in Table D–5 of this appendix. At least one required continuous analyzer in each MSA must be collocated with one of the required FRM/FEM/ARM [federal reference method/federal equivalent method/approved regional method] monitors, unless at least one of the required FRM/FEM/ARM monitors is itself a continuous FEM or ARM monitor in which case no collocation requirement applies." These minimum continuous $PM_{2.5}$ monitoring requirements are currently met in all MSAs in the Commonwealth. Also, the continuous $PM_{2.5}$ collocation requirements are currently met in all MSAs. Therefore, the continuous $PM_{2.5}$ monitoring network described in the Network Plan meets all of the design criteria of 40 CFR Part 58.

$PM_{2.5}$ Background and Transport Sites
40 CFR Part 58, Appendix D, Section 4.7.3

Regulatory requirements in 40 CFR Part 58, Appendix D, Section 4.7.3 require that "Each State shall install and operate at least one $PM_{2.5}$ site to monitor for regional background and at least one $PM_{2.5}$ site to monitor for regional transport." The Network Plan identifies the Grayson Lake $PM_{2.5}$ site (AQS ID: 21-043-0500) as a background site and the Hopkinsville $PM_{2.5}$ site (AQS ID: 21-047-0006) as a regional transport site. Therefore, the KDAQ has satisfied the requirements of 40 CFR Part 58 for background and transport sites.

$PM_{2.5}$ Chemical Speciation Network (CSN)
40 CFR Part 58, Appendix D, Section 4.7.4

The LMAPCD conducts $PM_{2.5}$ speciation monitoring at its Cannons Lane NCore site (AQS ID: 21-111-0067) in the Louisville/Jefferson County, KY-IN CBSA. The operation of this monitor is consistent with the CSN review recently completed by EPA.

Photochemical Assessment Monitoring Stations (PAMS)
40 CFR Part 58, Appendix D, Section 5.0

With promulgation of a revised O_3 NAAQS on October 1, 2015, the EPA finalized changes to the PAMS program. By June 1, 2019, PAMS monitoring will be required at the NCore site at Cannons Lane (AQS ID: 21-111-0067) in Louisville/Jefferson County.

To meet the PAMS requirements, the LMAPCD intends to install an auto GC, a ceilometer and a barometric pressure sensor by June 1, 2019. In addition, a new shelter we be installed to accommodate the new equipment. However, the LMAPCD, due to current funding limitations, does not believe the required ultraviolet pyranometer and carbonyls sampler will be installed until June 1, 2020. The EPA understands the LMAPCD's concerns and will work to get the required funding to the agency as soon as possible.

Memoranda of Agreement (MOA) with Neighboring States

Kentucky, Ohio, and Indiana have a MOA addressing $PM_{2.5}$, PM_{10}, O_3, NO_2, CO, and SO_2 monitoring in the Cincinnati, OH-KY-IN MSA. Kentucky and Indiana have a MOA addressing $PM_{2.5}$, PM_{10}, O_3, NO_2, CO, and SO_2 monitoring in the Evansville, IN-KY MSA. Kentucky and Tennessee have a MOA addressing $PM_{2.5}$ and O_3 monitoring in the Clarksville, TN-KY MSA. The other two multi-state MSAs are the Louisville/Jefferson County, KY-IN and the Huntington-Ashland, WV-KY-OH MSAs. Neither of these MSAs have MOAs for sharing monitoring requirements. If at some time in the future the KDAQ or the LMAPCD chooses to enter into a MOA with the neighboring states in those MSAs, the Network Plan should be updated to reflect that change and should include a copy of the signed MOA.

Site Assessments

In the Network Plan, for each monitoring site, the KDAQ and the LMAPCD have included the following site assessment information: last inspection date, photo of the site, condition of the sample lines and equipment, distance of the sample inlets from the nearest road, and a determination of whether the site meets the requirements of 40 CFR 58, Appendices A, B, C, D and E, where applicable. This information is very helpful. Thank you for all the work that your agencies have put forth to ensure sites meet siting criteria and please continue to update us annually on progress being made to correct deficiencies.

Appendix C

Louisville Gas & Electric Mill Creek Generating Station Permit No. 145-97-TV (R6)

Louisville Metro Air Pollution Control District
701 West Ormsby Avenue, Suite 303
Louisville, Kentucky 40203-3137

Title V Operating Permit

Permit No.: 145-97-TV (R6) Plant ID: 0127

Effective Date: 7/31/2014 Expiration Date: 7/31/2019

Permission is hereby given by the Louisville Metro Air Pollution Control District to operate the process(es) and equipment described herein which are located at:

Owner: Louisville Gas & Electric Company
Source: Mill Creek Generating Station
14460 Dixie Highway
Louisville, KY 40272

The applicable procedures of District Regulation 2.16 regarding review by the U.S. EPA and public participation have been followed in the issuance of this permit. Based on review of the application on file with the District, permission is given to operate under the conditions stipulated herein. If a renewal permit is not issued prior to the expiration date, the owner or operator may continue to operate in accordance with the terms and conditions of this permit beyond the expiration date, provided that a complete renewal application is submitted to the District no earlier than eighteen (18) months and no later than one-hundred eighty (180) days prior to the expiration date.

Applications:	See Applications and Related Documents
Administratively Complete:	1/29/2008
Date of Public Notice:	06/05/2014; 12/24/2016; 4/23/2017
Date of Proposed Permit:	06/05/2014; 12/24/2016; 2/21/2017; 4/23/2017

Permit writer: Yiqiu Lin

Matt K

Air Pollution Control Officer
11/19/2018

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Title V Permit Revisions/Changes

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<tr><td>Initial</td><td>145-97-TV</td><td>6/1/2003</td><td>1/19/2003</td><td>Initial</td><td>Entire Permit</td><td>Initial Issuance</td></tr>
<tr><td rowspan="2">R1</td><td>145-97-TV (R1)</td><td>7/31/2014</td><td>6/05/2014</td><td>Permit renewal</td><td>Entire Permit</td><td>Permit renewal and incorporate construction permit [a]</td></tr>
<tr><td colspan="6">a. Incorporated construction permits include 215-01, 216-01, 225-01, 142-05, 143-05, 144-05, 145-05, 37-07, 38-07, 426-07, 30399-11, 34595-12, 34658-12, 35668-12, 35673-12</td></tr>
<tr><td rowspan="2">R2</td><td>145-97-TV (R2)</td><td>3/16/2016</td><td>N/A</td><td>Admin. revision</td><td>Entire Permit</td><td>Insignificant changes made to incorporate updated information [b]</td></tr>
<tr><td colspan="6">b. Changes include the following:
1) Page 19, 22, 23, 30, and 35: Update Hg control requirements.
2) Page 40, 43, 44, 48, and 53: Update U4-C30 control efficiencies per stack test report.
3) Page 59, 63-64, 76-77, 82, 83, and 84: Add normal pressure range for U9 baghouses.
4) Page 89, 93-94, 102, 103, 108, 109, and 111: Revise TAC emission standards to exclude Category 3 & 4 TACs for existing sources and use de minimis values as emission standards.
5) Page 120, 123, and 340: Add BART requirements.</td></tr>
<tr><td rowspan="3">R3</td><td rowspan="2">145-97-TV (R3)</td><td rowspan="2">4/05/2017</td><td rowspan="2">12/24/2016</td><td>Admin. revision</td><td>Entire Permit</td><td>Administrative changes made to incorporate updated information [c]</td></tr>
<tr><td>Significant revision</td><td>Entire Permit</td><td>Significant changes made to incorporate updated information [d]</td></tr>
<tr><td colspan="6">c. Administrative changes include the following:
1) Create Plantwide Requirements section to include plantwide emission standards.
2) Convert unit comments to footnotes.
3) Update MACT requirements per technical corrections document 81 FR 20172.
4) Add footnote for new control devices startup date per submitted notifications.
5) Add normal pressure drop range for U1-4 PJFF established by testing.
6) Delete unit IA-EG since source does not have equipment covered by this emission unit.
7) Add unit IA-OT for insignificant activities that subject to specific emission standards.
8) Add de-dusting system to Unit 20, NPR.
9) Add fuel additive for NOx and Hg to Unit 21, NPR.
10) Add gypsum dewatering systems to IA Table, NPR.
11) Clarify averaging period for PM emission limits per regulation 7.08.
12) Update bypass language for PM and SO_2 control devices.
13) Add normal pH range for U1-U4 FGD.
14) Add normal pressure drop range for U9 Flyash Transfer Bins baghouses.
d. Significant changes include the following:
1) Incorporate CSAPR applicable requirements.
2) Add 30 days average SO_2 standards per NAAQS and modeling.
3) Incorporate Jan. 21, 2016 STAR EA Demo revised for sulfuric acid emissions. Add sulfuric acid emission limits for each EGU.</td></tr>
<tr><td rowspan="2">R4</td><td rowspan="2">145-97-TV (R4)</td><td rowspan="2">6/01/2017</td><td rowspan="2">4/23/2017</td><td>Admin. revision</td><td>Entire Permit</td><td>Updated CSAPR requirements; Incorporate new ash silos (IA)</td></tr>
<tr><td>Significant revision</td><td>Entire Permit</td><td>Incorporate CAIR applicable requirements</td></tr>
</table>

Revision No.	Permit No.	Issue Date	Public Notice Date	Change Type	Change Scope	Description
R5	145-97-TV (R5)	7/17/2017	N/A	Admin revision	I.A. table Unit IA-OT	Incorporate new mixers into IA table and IA unit
R6	145-97-TV (R6)	11/19/2018	N/A	Admin revision	I.A. table Unit IA3 and IA-OT	Incorporate new generator and PWS into IA table and IA units

Applications and Related Documents

Documents No.	Date	Description
65329/65330	11/30/2007	Title V Permit Renewal Application [1]
8534	6/3/2009	Notification of Addition of Limestone Crusher and Ball Mill [1]
52426	12/14/2012	Notification of Relocation of Central Service Shop [1]
54494	3/5/2013	Revised Permit Application for U4 FGD Upgrade [1]
54933	3/25/2013	Construction/Operating Application for Gypsum Pelletizing Plant [1]
55161	4/3/2013	District Response Gypsum Pelletizing Plant Operating Permit [1]
57168	7/10/2013	Construction/Operating Application for Limestone Silo [1]
58304	8/9/2013	Request of Extension of MATS Compliance Date [1]
58437	8/14/2013	Modification Application for Fly Ash Silos [1]
58896	8/30/2013	Submittal of Established Parameter range for Dust Collector [1]
60778	11/15/2013	Construction/Operating Application for Emergency Fire Pumps [1]
62614	2/21/2014	Updated 100B Forms for Equipment Incorporated in TV Permit [1]
65445	4/29/2014	Submittal of Requested Information for Coal Mills [1]
64614	4/30/2014	Construction/Operating Application for Upgraded Coal Crushers [1]
65396	6/4/2014	Submittal of Revised CAM Plan [1]
68244	12/2/2014	Request to Use Mercury Monitoring System for Compliance [2]
69942	7/21/2014	Request to Keep MATS SO_2 Limit/Remove Surrogate HCl Limit [3]
69947	3/6/2015	Submittal of Established Normal Pressure Range for U9 [2]
66136	7/21/2014	Application for Modification of U4 Cooling Tower Capacity [3]
66138	7/21/2014	Construction/Operating Application for De-dust System [3]
73924	10/15/2015	Request of SO_2 Standard Established Per SO_2 NAAQS [3]
74663	12/17/2015	Request of Utilizing Alternative Mercury Control [2]
74920	1/21/2016	Revised STAR EA Demo[3]

[1] For permit 145-97-TV (R1) renewal issued 7/31/2014.

[2] For permit 145-97-TV (R2) administrative revision issued 3/16/2016.

[3] For permit 145-97-TV (R3) administrative revision and significant revision issued 4/05/2017

Documents No.	Date	Description
75287	2/16/2016	Submittal of Certificate from Kentucky Secretary of State [3]
78480	7/22/2016	Submittal of Established Parameter range for PJFF [3]
79057	8/24/2016	District Response to I.A. Request for TV Revision [3]
79300	9/6/2016	Submitted Additional I.A. Information [3]
79405	9/13/2016	Correspondence of SO2 Standard Established Per SO2 NAAQS [3]
80105	10/20/2016	Submittal of Parameter Range for pH Unit 1-4
80107	10/20/2016	Application for SO2 Standard Established Per SO2 NAAQS [3]
80335	11/03/2016	Revised Appropriate Parameter Range for Unit 9 Flyash Transfer Bins baghouses[3]
81450, 81452, 81457	1/25/2017	Sierra Club's comments on Title V permit O-0127-16-V
81474, 81475, 81476, 81478, 81479	1/26/2017	Sierra Club's comments on permit O-0127-16-V sent to LG&E
81477	1/26/2017	Notification to EPA that comments were received from Sierra Club's comments on permit O-0127-16-V
81721	2/20/2017	District's response to public comments on permit O-0127-16-V
83087	3/24/2017	Application for Ash Silo
83159	3/29/2017	Initial comments received from EPA Region IV
83178	3/29/2017	Additional comments received from EPA Region IV
83270	3/30/2017	More comments form EPA
83465	3/31/2017	Additional information for Ash Silo
83272	4/3/2017	Company comments based on EPA comments
83468	4/11/2017	Additional information for Ash Silo
83582	4/13/2017	Manufacturer guarantee for Ash Silo
83605	4/17/2017	No permit required for construction permit for Ash Silo
83608	4/17/2017	Copy of 2007 CAIR Application
84423	5/25/2017	EPA Region IV comments on Significant Revision TV
84424	5/26/2017	District Response to EPA Region IV comments
84425	5/26/2017	Company copy of District Response to EPA Region IV comments
84528	6/02/2017	Updated Silo and Mixer Calculations
84574	6/06/2017	Updated Silo and Mixer Calculations
84737	6/14/2017	Approved PTE email and No Construction Permit needed

Abbreviations and Acronyms

AP-42	- AP-42, *Compilation of Air Pollutant Emission Factors*, published by US EPA
APCD	- Louisville Metro Air Pollution Control District
BAC	- Benchmark Ambient Concentration
BACT	- Best Available Control Technology
Btu	- British thermal unit
CEMS	- Continuous Emission Monitoring System
CFR	- Code of Federal Regulations
CO	- Carbon monoxide
District	- Louisville Metro Air Pollution Control District
EA	- Environmental Acceptability
gal	- U.S. fluid gallons
GHG	- Greenhouse Gas
HAP	- Hazardous Air Pollutant
Hg	- Mercury
hr	- Hour
in.	- Inches
lbs	- Pounds
l	- Liter
LMAPCD	- Louisville Metro Air Pollution Control District
mmHg	- Millimeters of mercury column height
MM	- Million
NAICS	- North American Industry Classification System
NO_x	- Nitrogen oxides
PM	- Particulate Matter
PM_{10}	- Particulate Matter less than 10 microns
$PM_{2.5}$	- Particulate Matter less than 2.5 microns
ppm	- parts per million
PSD	- Prevention of Significant Deterioration
psia	- Pounds per square inch absolute
QA	- Quality Assurance
RACT	- Reasonably Available Control Technology
SIC	- Standard Industrial Classification
SIP	- State Implementation Plan
SO_2	- Sulfur dioxide
STAR	- Strategic Toxic Air Reduction
TAC	- Toxic Air Contaminant
UTM	- Universal Transverse Mercator
VOC	- Volatile Organic Compound
w.c.	- Water column
year	- Any period of twelve consecutive months, unless "calendar year" is specified
yr	- Year, or any 12 consecutive-month period, as determined by context

Preamble

Title V of the Clean Air Act Amendments of 1990 (the Act) required EPA to create an operating permit program for implementation by state or local air permitting authorities. The purposes of this program are: (1) to require an affected company to assume full responsibility for demonstrating compliance with applicable regulations; (2) to capture all of the regulatory information pertaining to an affected company in a single document; and (3) to make permits more consistent with each other.

A company is subject to the Title V program if it meets any of several criteria related to the nature or amount of its emissions. The Title V operating permit specifies what the affected company is, how it may operate, what its applicable regulations are, how it will demonstrate compliance, and what is required if compliance is not achieved. In Jefferson County, Kentucky, the Louisville Metro Air Pollution Control District (LMAPCD or APCD) is responsible for issuing Title V permits to affected companies and enforcing local regulations and delegated federal and state regulations. EPA may enforce federal regulations but not "District Only Enforceable Regulations."

Title V offers the public an opportunity to review and comment on a company's draft permit. It is intended to help the public understand the company's compliance responsibility under the Clean Air Act. Additionally, the Title V process provides a mechanism to incorporate new applicable requirements. Such requirements are available to the public for review and comment before they are adopted.

Title V Permit General Conditions define requirements that are generally applicable to all Title V companies under the jurisdiction of LMAPCD. This avoids repeating these requirements in every section of the company's Title V permit. Company-specific conditions augment the General Conditions as necessary; these appear in the sections of the permit addressing individual emission units or emission points.

The General Conditions include references to regulatory requirements that may not currently apply to the company, but which provide guidance for potential changes at the company or in the regulations during the life of the permit. Such requirements may become applicable if the company makes certain modifications or a new applicable requirement is adopted.

When the applicability of a section or subpart of a regulation is unclear, a clarifying citation will be made in the company's Title V permit at the emission unit/point level. Comments may also be added at the emission unit/point level to give further clarification or explanation.

The owner or operator's Title V permit may include a current table of "insignificant activities."

Insignificant activities are defined in District Regulation 2.16 section 1.23, as of the date the permit was proposed for review by U.S. EPA, Region 4.

Insignificant activities identified in District Regulation 1.02, section 1.38, and Appendix A may be subject to size or production rate disclosure requirements pursuant to Regulation 2.16 section 3.5.4.1.4.

Insignificant activities identified in District Regulation 1.02, section 1.38, and Appendix A shall comply with generally applicable requirements as required by Regulation 2.16 section 4.1.9.4.

General Conditions

1. **Compliance** - The owner or operator shall comply with all applicable requirements and with all terms and conditions of this permit. Any noncompliance shall constitute a violation of the Act, State, and District regulations and shall cause the source to be subject to enforcement actions including, but not limited to, the termination, revocation and reissuance, or revision of this permit, or denial of a permit application to renew this permit. Notwithstanding any other provision in the Jefferson County portion of the Kentucky SIP approved by EPA, any credible evidence may be used for the purpose of establishing whether the owner or operator is in compliance with, has violated, or is in violation of any such plan. [Regulation 2.16, sections 4.1.3, 4.1.13.1, and 4.1.13.7]

2. **Compliance Certification** - The owner or operator shall certify, annually, or more frequently if required in applicable regulations, compliance with the terms and conditions contained in this permit, including emission limitations, standards, or work practices. This certification shall meet the requirements of Regulation 2.16, sections 3.5.11 and 4.3.5. The owner or operator shall submit the annual compliance certification (Form 9400-O) directly to the EPA and to the District, as set forth in Regulation 2.16, section 4.3.5.4, at the following addresses:

   US EPA - Region IV
   Air Enforcement Branch
   Atlanta Federal Center
   61 Forsyth Street
   Atlanta, GA 30303-8960

   Air Pollution Control District
   701 W. Ormsby Avenue, Suite 303
   Louisville, Kentucky 40203-3137

   This certification must be postmarked by 15 April of the year following the year for which the certification is being submitted, or other such due date as required by another applicable regulation.

3. **Compliance Schedule** - The owner or operator shall submit a schedule of compliance for each emission unit that is not in compliance with all applicable requirements. A compliance schedule must meet the requirements of Regulation 2.16, section 3.5.9.5. A schedule of compliance shall be supplemental to, and shall not condone noncompliance with, the applicable requirements on which it is based. For each schedule of compliance, the owner or operator shall submit certified progress reports at least semi-annually, or at a more frequent period if specified in an applicable requirement or by the District in accordance with Regulation 2.16 section 4.3.4. The progress reports shall contain:

   a. Dates for achieving the activities, milestones, or compliance required in the schedule of compliance, and dates when activities, milestones, or compliance were achieved.

   b. An explanation of why dates in the schedule of compliance were not or will not be met, and preventive or corrective measures adopted.

4. **Duty to Supplement or Correct Application** - If the owner or operator fails to submit relevant facts or has submitted incorrect information in the permit application, they shall,

upon discovery of the occurrence, promptly submit the supplementary facts or corrected information in accordance with Regulation 2.16, section 3.4.

5. **Emergency Provision**

a. An emergency shall constitute an affirmative defense to an enforcement action brought for noncompliance with technology-based emission limitations if the conditions in Regulation 2.16 are met. The affirmative defense of emergency shall be demonstrated through properly signed, contemporaneous operating logs, or other relevant evidence that:

i. An emergency occurred and that the owner or operator can identify the cause of the emergency;

ii. The permitted facility was at the time being properly operated;

iii. During the period of the emergency the owner or operator expeditiously took all reasonable steps, consistent with safe operating practices, to minimize levels of emissions that exceeded the emission standards or other requirements in this permit; and

iv. The owner or operator submitted notice meeting the requirements of Regulation 1.07 of the time when emissions limitations were exceeded because of the emergency. This notice must fulfill the requirement of this condition, and must contain a description of the emergency, any steps taken to mitigate emissions, and any corrective actions taken.

b. In an enforcement proceeding, the owner or operator seeking to establish the occurrence of an emergency has the burden of proof.

c. This condition is in addition to any emergency or upset provision contained in an applicable requirement. [Regulation 2.16, sections 4.7.1 through 4.7.4]

6. **Emission Fees Payment Requirements** - The owner or operator shall pay annual emission fees in accordance with Regulation 2.08, section 12.3. Failure to pay the emissions fees when due shall constitute a violation of District Regulations. Such failure is subject to penalties and an increase in the fee of an additional 5% per month up to a maximum of 25% of the original amount due. In addition, failure to pay emissions fees within 60 days of the due date shall automatically suspend this permit to operate until the fee is paid or a schedule for payment acceptable to the District has been established. [Regulation 2.08, section 12.2.4]

7. **Emission Offset Requirements** - The owner or operator shall comply with the requirements of Regulation 2.04.

8. **Enforceability Requirements** - Except for the conditions that are specifically designated as District-Only Enforceable Conditions, all terms and conditions of this permit, including any provisions designed to limit a source's potential to emit, are enforceable by EPA and citizens as specified under the Act. [Regulation 2.16, sections 4.2.1 and 4.2.2]

9. **Enforcement Action Defense**

a. It shall not be a defense for the owner or operator in an enforcement action that it would have been necessary for the owner or operator to halt or reduce the permitted activity in order to maintain compliance with the conditions of this permit.

b. The owner or operator's failure to halt or reduce activity may be a mitigating factor in assessing penalties for noncompliance if the health, safety or environmental impacts of halting or reducing operations would be more serious than the impacts of continued operation. [Regulation 2.16, sections 4.1.13.2 and 4.1.13.3]

10. **Hazardous Air Pollutants and Sources Categories** - The owner or operator shall comply with the applicable requirements of Regulations 5.02 and 5.14.

11. **Information Requests** - The owner or operator shall furnish to the District, within a reasonable time, information requested in writing by the District, to determine whether cause exists for revising, revoking and reissuing, or terminating this permit, or to determine compliance with this permit. The owner or operator shall also furnish, upon request, copies of records required to be kept by this permit.
[Regulation 2.16, section 4.1.13.6]

If information is submitted to the District under a claim of confidentiality, the source shall submit a copy of the confidential information directly to EPA at the address shown in General Condition 35.b. [Regulation 2.07, section 10.2]

12. **Insignificant Activities** - The owner or operator shall:

a. Notify the District in a timely manner of any proposed change to an insignificant activity that would require a permit revision. [Regulation 2.16, section 5]

b. Submit a current list of insignificant activities by April 15 of each year with the annual compliance certification, including an identification of the additions and removals of insignificant activities that occurred during the preceding year. [Regulation 2.16, section 4.3.5.3.6]

13. **Inspection and Entry** - Upon presentation of credentials and other documents as required by law, the owner or operator shall allow the District or an authorized representative to perform the following during reasonable hours:
[Regulation 2.16, section 4.3.2]

a. Enter the premises to inspect any emissions-related activity or records required in this permit.

b. Have access to and copy records required by this permit.

c. Inspect facilities, equipment (including monitoring and air pollution control equipment), practices, or operations regulated or required by this permit.

d. Sample or monitor substances or parameters to assure compliance with this permit or any applicable requirements.

14. **Monitoring and Related Record Keeping and Reporting Requirement** - The owner or operator shall comply with the requirements of Regulation 2.16, section 4.1.9. Unless specified elsewhere in this permit, the owner or operator shall complete required monthly record keeping within 30 days following the end of each calendar month. The owner or operator shall submit all required monitoring reports at least once every six months, unless

more frequent reporting is required by an applicable requirement. The reporting period shall be 1 January through 30 June and 1 July through 31 December of each calendar year. All reports shall be sent to the District at the address shown in paragraph 2 of these General Conditions and must be postmarked by the 60th day following the end of each reporting period, unless specified elsewhere in this permit. If surrogate operating parameters are monitored and recorded in lieu of emission monitoring, then an exceedance of multiple parameters may be deemed a single violation by the District for enforcement purposes. All reports shall include the company name, plant ID number, and the beginning and ending date of the reporting period. The compliance reports shall clearly identify any deviation from a permit requirement or a declaration that there were no such deviations. All semi-annual compliance reports shall include the statement "Based on information and belief formed after reasonable inquiry, I certify that the statements and information in this document are true, accurate, and complete" and the signature and title of a responsible official of the company.

The semi-annual compliance reports are due on or before the following dates of each calendar year:

Reporting Period	Report Due Date
January 1 - June 30	August 29
July 1 - December 31	March 1 of the following year

If a change in the responsible official (RO) occurs during the term of this permit, or if an RO is added, the owner or operator shall provide written notification (Form AP-100A) to the District within 30 calendar days of such change or addition.

15. **Off-permit Documents** - Any applicable requirements, including emission limitations, control technology requirements, or work practice standards, contained in an off-permit document cannot be changed without undergoing the permit revision procedures in Regulation 2.16, section 5. [Regulation 2.16, section 4.1.5]

16. **Operational Flexibility** - The owner or operator may make changes without permit revision in accordance with Regulation 2.16, section 5.8.

17. **Permit Amendments (Administrative)** - This permit can be administratively amended by the District in accordance with Regulation 2.16, section 5.4.

18. **Permit Application Submittal** - The owner or operator shall submit a timely and complete application for permit renewal or significant revision. If the owner or operator submits a timely and complete application then the owner or operator's failure to have a permit is not a violation until the District takes formal action on this permit application. This protection shall cease to apply if, subsequent to completeness determination, the owner or operator fails to submit, by the deadline specified in writing by the District, additional information required to process the application as required by Regulation 2.16, sections 3 and 5.2.

19. **Permit Duration** - This permit is issued for a fixed term of 5 years, in accordance with Regulation 2.16, section 4.1.8.3.

20. **Permit Renewal, Expiration and Application** - Permit renewal, expiration and application procedural requirements shall be in accordance with Regulation 2.16, sections 4.1.8.2 and 5.3. This permit may only be renewed in accordance with section 5.3.

21. **Permit Revisions** - No permit revision shall be required under any approved economic incentives, marketable permits, emissions trading and other similar programs or processes for changes that are provided for in the permit. [Regulation 2.16, section 4.1.16]

22. **Permit Revision Procedures (Minor)** - Except as provided in 40 CFR Part 72, the Acid Rain Program, this permit may be revised in accordance with Regulation 2.16, section 5.5.

23. **Permit Revision Procedures (Significant)** - A source seeking to make a significant permit revision shall meet all the Title V requirements for permit applications, issuance and Permit renewal, in accordance with Regulation 2.16, section 5.7, and all other applicable District Regulations.

24. **Permit Termination and Revocation by the District** - The District may terminate this permit only upon written request of the owner or operator. The District may revoke a permit for cause, in accordance with Regulation 2.16, section 5.11.1 through 5.11.6. For purposes of section 5.11.1, substantial or unresolved noncompliance includes, but is not limited to:

    a. Knowingly operating process or air pollution control equipment in a manner not allowed by an applicable requirement or that results in excess emissions of a regulated air pollutant that would endanger the public or the environment;

    b. Failure or neglect to furnish information, analyses, plans, or specifications required by the District;

    c. Knowingly making any false statement in any permit application;

    d. Noncompliance with Regulation 1.07, section 4.2; or

    e. Noncompliance with KRS Chapter 77.

25. **Permit Shield** - The permit shield shall apply in accordance with Regulation 2.16, section 4.6.1.

26. **Prevention of Significant Deterioration of Air Quality** - The owner or operator shall comply with the requirements of Regulation 2.05.

27. **Property Rights** - This permit shall not convey property rights of any sort or grant exclusive privileges in accordance with Regulation 2.16, section 4.1.13.5.

28. **Public Participation** - Except for modifications qualifying for administrative permit amendments or minor permit revision procedures, all permit proceedings shall meet the requirements of Regulations 2.07, section 1; and 2.16, sections 5.1.1.2 and 5.5.4.

29. **Reopening For Cause** - This permit shall be reopened and revised by the District in accordance with Regulation 2.16 section 5.9.

30. **Reopening for Cause by EPA** - This permit may be revised, revoked and reissued or terminated for cause by EPA in accordance with Regulation 2.16 section 5.10.

31. **Risk Management Plan (112(r))** - For each process subject to section 112(r) of the Act, the owner or operator shall comply with 40 CFR Part 68 and Regulation 5.15.

32. **Severability Clause** - The conditions of this permit are severable. Therefore, if any condition of this permit, or the application of any condition of this permit to any specific circumstance, is determined to be invalid, the application of the condition in question to

other circumstances, as well as the remainder of this permit's conditions, shall not be affected. [Regulation 2.16, section 4.1.12]

33. **Stack Height Considerations** - The owner or operator shall comply with the requirements of Regulation 2.10.

34. **Startups, Shutdowns, and Upset Conditions Requirements** - The owner or operator shall comply with the requirements of Regulation 1.07.

35. **Submittal of Reports, Data, Notifications, and Applications**

a. Applications, reports, test data, monitoring data, compliance certifications, and any other document required by this permit as set forth in Regulation 2.16 sections 3.1, 3.3, 3.4, 3.5, 4.1.13.6, 5.8.5 and 5.12 shall be submitted to:

Air Pollution Control District
701 West Ormsby Avenue, Suite 303
Louisville, Kentucky 40203-3137

b. Documents that are specifically required to be submitted to EPA, as set forth in Regulation 2.16 sections 3.3 and 5.8.5 shall be mailed to EPA at:

US EPA - Region IV
APTMD - 12th floor
Atlanta Federal Center
61 Forsyth Street
Atlanta, GA 30303-3104

36. **Other Applicable Regulations** - The owner or operator shall comply with all applicable requirements of the following:

Regulation	Title
1.01	General Application of Regulations and Standards
1.02	Definitions
1.03	Abbreviations and Acronyms
1.04	Performance Tests
1.05	Compliance With Emissions Standards And Maintenance Requirements
1.06	Source Self-Monitoring, Emission Inventory Development and Reporting
1.07	Excess Emissions During Startups, Shutdowns, and Upset Conditions
1.08	Administrative Procedures
1.09	Prohibition of Air Pollution
1.10	Circumvention
1.11	Control of Open Burning
1.14	Control of Fugitive Particulate Emissions
2.01	General Application (Permit Requirements)
2.02	Air Pollution Regulation Requirements and Exemptions
2.03	Authorization to Construct or Operate; Demolition/Renovation Notices and Permit Requirements
2.07	

Regulation	Title
	Public Notification for Title V, PSD, and Other Offset Permits; SIP Revisions; and Use of Emission Reduction Credits
2.09	Causes for Permit Modification, Revocation, or Suspension
2.10	Stack Height Considerations
2.11	Air Quality Model Usage
2.16	Title V Operating Permits
4.01	General Provisions for Emergency Episodes
4.02	Episode Criteria
4.03	General Abatement Requirements
4.07	Episode Reporting Requirements
5.02	Adoption and Incorporation by Reference of National Emission Standards for Hazardous Air Pollutants
6.01	General Provisions (Existing Affected Facilities)
6.02	Emission Monitoring for Existing Sources
7.01	General Provisions (New Affected Facilities)
7.02	Adoption and Incorporation by Reference of Federal New Source Performance Standards

District Only Enforceable Regulations:

Regulation	Title
1.12	Control of Nuisances
1.13	Control of Objectionable Odors
2.08	Emission Fee, Permit Fees and Permit Renewal Procedures
5.00	Definitions
5.01	General Provisions
5.20	Methodology for Determining Benchmark Ambient Concentration of a Toxic Air Contaminant
5.21	Environmental Acceptability for Toxic Air Contaminants
5.22	Procedures for Determining the Maximum Ambient Concentration of a Toxic Air Contaminant
5.23	Categories of Toxic Air Contaminants

37. **Stratospheric Ozone Protection Requirements** - Any facility having refrigeration equipment, including air conditioning equipment, which uses a Class I or II substance (listed in 40 CFR 82, Subpart A, Appendices A and B), and any facility which maintains, services, or repairs motor vehicles using a Class I or II substance as refrigerant must comply with all requirements of 40 CFR 82, Subparts A, B, and F. Those requirements include the following restrictions:

a. Any facility having any refrigeration equipment that normally contains fifty (50) pounds of refrigerant or more must keep servicing records documenting the date and type of all service and the quantity of any refrigerant added, according to 40 CFR 82.166;

b. No person repairing or servicing a motor vehicle may perform any service on a motor vehicle air conditioner (MVAC) involving the refrigerant for such air conditioner unless the person has been properly trained and certified as provided in 40 CFR 82.34 and 40 CFR 82.40, and properly uses equipment approved according to 40 CFR 82.36 and 40 CFR 82.38, and complies with 40 CFR 82.42;

c. No person may sell or distribute, or offer for sale or distribution, any substance listed as a Class I or II substance in 40 CFR 82, Subpart A, Appendices A and B, except in compliance with 40 CFR 82.34(b), 40 CFR 82.42, and/or 40 CFR 82.166;

d. No person maintaining, servicing, repairing, or disposing of appliances may knowingly vent or otherwise release into the atmosphere any Class I or II substance used as a refrigerant in such equipment and no other person may open appliances (except MVACs as defined in 40 CFR 82.152) for service, maintenance, or repair unless the person has been properly trained and certified according to 40 CFR 82.161 and unless the person uses equipment certified for that type of appliance according to 40 CFR 82.158 and unless the person observes the practices set forth in 40 CFR 82.156 and 40 CFR 82.166;

e. No person may dispose of appliances (except small appliances, as defined in 40 CFR 82.152) without using equipment certified for that type of appliance according to 40 CFR 82.158 and without observing the practices set forth in 40 CFR 82.156 and 40 CFR 82.166;

f. No person may recover refrigerant from small appliances, MVACs and MVAC-like appliances (as defined in 40 CFR 82.152), except in compliance with the requirements of 40 CFR 82 Subpart F;

g. If the permittee manufactures, transforms, imports, or exports, a Class I or II substance (listed in 40 CFR 82, Subpart A, Appendices A and B), the permittee is subject to all requirements as specified in 40 CFR 82 Subpart A, Production and Consumption Controls. [Regulation 2.16, section 4.1.5]

Plantwide Requirements

Facility Description:

Louisville Gas & Electric- Mill Creek Generating Station generates electric energy for local and remote distribution. Coal is the primary fuel used to fire commercial boilers for generation of electricity via steam turbines and generators.

Plantwide Applicable Regulations:

FEDERALLY ENFORCEABLE REGULATIONS		
Regulation	**Title**	**Applicable Sections**
2.16	Title V Operating Permits	1 through 6
40 CFR 52 Subpart A	Approval and Promulgation of Implementation Plans – General Provisions	52.01through 52.39
40 CFR 68, Subpart G	Risk Management Plan	68.150 through 68.195
40 CFR 97, Subpart AAAAA	CSAPR NO_X Annual Trading Program	97.401 through 97.435
40 CFR 97, Subpart EEEEE	CSAPR NOX Ozone Season Group 2 Trading Program	97.801 through 97.835
40 CFR 97, Subpart CCCCC	CSAPR SO_2 Group 1 Trading Program	97.601 through 97.635

DISTRICT ONLY ENFORCEABLE REGULATIONS		
Regulation	**Title**	**Applicable Sections**
5.00	Definitions	1, 2
5.01	General Provisions	1 through 2
5.20	Methodology for Determining Benchmark Ambient Concentration of a Toxic Air Contaminant	1 through 6
5.21	Environmental Acceptability for Toxic Air Contaminants	1 through 5
5.22	Procedures for Determining the Maximum Ambient Concentration of a Toxic Air Contaminant	1 through 5
5.23	Categories of Toxic Air Contaminants	1 through 6

Plantwide Specific Conditions

S1. **Standards** (Regulation 2.16 Section 4.1.1)

a. **SO_2**

i. The owner or operator shall not allow SO_2 emissions from any of the boilers U1, U2, U3, or U4, to exceed 0.20 lb/MMBtu of heat input based on a rolling 30-day average.[4] (40 CFR 52)

b. **TAC**

i. The owner or operator shall not allow emissions of any TAC to exceed environmentally acceptable (EA) levels, whether specifically established by modeling or determined by the District to be *de minimis*. (Regulations 5.00 and 5.21) (See Comment 1)

ii. The owner or operator shall submit with the application for construction for any new emission unit the STAR EA Demonstration for all Category 1 through Category 4 TACs emitted from that emission unit. (Regulation 5.21, section 4.22.1)

iii. The owner or operator shall submit a plantwide emissions-based EA Demonstration to the District showing compliance with the EA goals for each TAC from each process when a change occurs that increases emissions above de minimis or previously modeled values. (Regulation 5.21, section 4.22.3)

iv. If the TAC does not have an established BAC or de minimis value, the owner or operator shall calculate and report these values. The form, located in Attachment J - Determination of Benchmark Ambient Concentration (BAC), may be used for determining BAC and de minimis values. (Regulation 5.20, sections 3 and 4)

c. **District Regulation 5.15 Regulated Substance (40 CFR 68, Subpart G)**

If any toxic substances listed in Tables 1 through 4 to 40 CFR 68.130 are present at the stationary source in an amount greater than the threshold quantity specified

[4] KDAQ and APCD performed AERMOD modeling for attainment of 1-hour SO_2 NAAQS at LG&E Mill Creek Station. Based on the modeled critical SO_2 emission rate and an established 30-day vs. 1-hour SO_2 emission ratio, the suggested 30-day average critical SO_2 emission rates for each emission unit are determined. APCD believes an average single compliance ratio for all emission units would reasonably reflect the variability of emissions for the whole plant. Also the same single emission limit for each unit is more conservative since the calculated annual potential total SO_2 emissions based on the single limit 0.20 lb/MMBtu for all units are less than the total SO_2 emissions based on the separate different limit for each unit. On October 20, 2016, LG&E submitted an application form AP-100A and requested the emission standards to be incorporated into its Title V permit.

in Regulation 5.15, the owner or operator shall comply with the requirements specified in Regulation 5.15, including the requirement to submit a Risk Management Plan in a method and format as specified by the District and EPA.

d. **Cross-State Air Pollution Rule (CSAPR)**

The owner or operator shall comply with CSAPR applicable requirements in 40 CFR 97, Subpart AAAAA, Subpart EEEEE, and Subpart CCCCC (See Attachment G).

S2. **Monitoring and Record Keeping** (Regulation 2.16 Section 4.1.9.1 and 4.1.9.2)

a. **SO_2**

i. See each emission unit (U1, U2, U3, and U4) for the specific monitoring *and record keeping requirements.*

ii. The owner or operator shall, on a daily basis, monitor and keep records of fuel type, feed rate (or firing rate) of each boiler (U1, U2, U3, and U4).

b. **TAC**

i. The owner or operator shall maintain records sufficient to demonstrate environmental acceptability, including, but not limited to MSDS, analysis of emissions, and/or modeling results.

ii. If a new TAC is introduced or the content of a TAC in a raw material increases above de minimis, the owner or operator shall verify and document the environmental acceptability of the revised emissions, at the time of the change.

c. **District Regulation 5.15 Regulated Substance (40 CFR 68, Subpart G)**

If any toxic substances listed in Tables 1 through 4 to 40 CFR 68.130 are present at the stationary source in an amount greater than the threshold quantity specified in Regulation 5.15, the owner or operator shall monitor the processes and keep records required by Regulation 5.15.

d. **Cross-State Air Pollution Rule (CSAPR)**

The owner or operator shall comply with CSAPR applicable requirements in 40 CFR 97, Subpart AAAAA, Subpart EEEEE, and Subpart CCCCC (See Attachment G).

S3. **Reporting** (Regulation 2.16 Section 4.1.1)

The owner or operator shall submit quarterly compliance reports that include the information in this section. (See Comment 2)

a. **SO_2**

i. See each emission unit (U1, U2, U3, and U4) for the specific reporting requirements.

ii. Excess emissions for affected facilities (U1, U2, U3, and U4) are defined as: (40 CFR 52)

1) For affected facilities complying with the 0.20 lb/MMBtu emission standard, any 30 operating day period during which the average emissions (arithmetic average of all one-hour periods during the 30 operating days) of SO_2 as measured by a CEMS exceed the standard.

b. **TAC**

i. The owner or operator shall report any conditions that were inconsistent with those conditions analyzed in the most recent Environmental Acceptability Demonstration or a negative declaration stating that operations were within the conditions analyzed. This includes, but is not limited to, control device upset conditions.

ii. For any conditions outside the analysis, the owner or operator shall re-analyze to determine whether these conditions comply with the STAR program. Changes to the air dispersion modeling program or meteorological data used in the most recent Environmental Acceptability Demonstration do not trigger the requirement to re-analyze.
(Regulation 5.21 sections 4.22 – 4.24)

iii. The owner or operator shall submit the re-evaluated EA demonstration to the District within 6 months after a change of a raw material.

c. **District Regulation 5.15 Regulated Substance (40 CFR 68, Subpart G)**

If any toxic substances listed in Tables 1 through 4 to 40 CFR 68.130 are present at the stationary source in an amount greater than the threshold quantity specified in Regulation 5.15, the owner or operator shall comply with the reporting requirements specified in Regulation 5.15, including the requirement to submit a Risk Management Plan in a method and format as specified by the District and EPA.

d. **Cross-State Air Pollution Rule (CSAPR)**

The owner or operator shall comply with CSAPR applicable requirements in 40 CFR 97, Subpart AAAAA, Subpart EEEEE, and Subpart CCCCC (See Attachment G).

Comments for Plantwide Requirements

1. LG&E Mill Creek submitted their TAC Environmental Acceptability Demonstration to the District on December 28, 2006, March 25, 2008, April 9, 2010, April 2, 2012, May 13, 2014, and January 21, 2016. Compliance with the STAR EA Goals was demonstrated in the source's EA Demonstrations. SCREEN3 air dispersion modeling was performed for each emission unit that has non-de minimis TAC emissions. The following table demonstrates that the carcinogen risk and non-carcinogen risk values, calculated using the District approved PTE for each unit and the SCREEN model results from the source's EA Demonstration, comply with the STAR EA goals required in Regulation 5.21 controlled.

Plantwide Sum	All existing & new		All new P/PE	
Industrial Total R_C	4.16	< 75	0.61	< 38
Non-Ind. Total R_C	4.16	< 7.5	0.61	< 3.8
Industrial Max. R_{NC}	0.16	< 3.0		
Non-Ind. Max. R_{NC}	0.16	< 1.0		

	R_{NC} Total		**U1**		**U2**		**U3**		**U4**		**U8**		**U9**		**U22**	
	Ind./Non-Ind.		Ind./Non-Ind.		Ind./Non-Ind.		Ind./Non-Ind.		Ind./Non-Ind.		Ind./Non-Ind.		Ind./Non-Ind.		Ind./Non-Ind.	
TAC	R_{NC}	R_{NC}	R_C	R_{NC}	R_C	R_{NC}	R_C	R_{NC}	R_C	R_{NC}	R_C	R_{NC}	R_C	R_{NC}	R_C	R_{NC}
Total R_C/ Max. R_{NC}	**0.16**	**0.16**	**0.65**		**0.65**		**1.09**		**1.07**		**0.58**		**0.10**		**0.03**	
Arsenic and arsenic co	0.03	0.03	0.29	0.00	0.29	0.00	0.48	0.01	0.48	0.01	0.56	0.01	0.10	0.002	0.02	0.00
Cadmium and cadmium	0.00	0.00	0.02	0.00	0.02	0.00	0.03	0.00	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Chromium hexavalent &	0.02	0.02	0.28	0.00	0.28	0.00	0.48	0.00	0.47	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Chromium trivalent & Cr	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Formaldehyde	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Nickel and nickel compo	0.03	0.03	0.02	0.01	0.02	0.01	0.03	0.01	0.03	0.01	0.00	0.00	0.00	0.00	0.00	0.00
Cobalt and cobalt comp	0.01	0.01	0.03	0.00	0.03	0.00	0.06	0.00	0.06	0.00	0.03	0.001	0.00	0.00	0.00	0.00
Hydrofluoric acid [Hydr	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Lead compounds1	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Manganese and Manga	0.01	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Naphthalene	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Sulfuric acid	0.16	0.16	0.00	0.03	0.00	0.03	0.00	0.05	0.00	0.05	0.00	0.00	0.00	0.00	0.00	0.00

2. The compliance reports are due on or before the following dates of each calendar year:

<u>Reporting Period</u>	<u>Report Due Date</u>
January 1st through March 31th	May 30th
April 1st through June 30th	August 29th
July 1st through September 30th	November 29th
October 1st through December 31st	March 1st

Emission Unit U1: Electric Utility Steam Generating Unit (EGU) – Unit 1

U1 Applicable Regulations:

FEDERALLY ENFORCEABLE REGULATIONS		
Regulation	**Title**	**Applicable Sections**
6.02	Emission Monitoring for Existing Sources	1, 2, 5, 6, 7, 8, 9, 10, 11, 12, 13, 14, 15, 16, 17, 18
6.07	Standards of Performance for Existing Indirect Heat Exchangers	1, 2, 3, 4
6.09	Standards of Performance for Existing Process Operations	1, 2, 3, 5
6.42	Reasonably Available Control Technology Requirements for Major Volatile Organic Compound- and Nitrogen Oxides-Emitting Facilities	1, 2, 3, 4, 5
6.47	Federal Acid Rain Program for Existing Sources Incorporated by Reference	1, 2, 3, 4, 5
40 CFR 64	Compliance Assurance Monitoring for Major Stationary Sources	64.1 through 64.10
40 CFR 72	Permits Regulation	Subparts A, B, C, D, E, F, G, H, I
40 CFR 73	Sulfur Dioxide Allowance System	Subparts A, B, C, D, E, F, G
40 CFR 75	Continuous Emission Monitoring	Subparts A, B, C, D, E, F, G
40 CFR 76	Acid Rain Nitrogen Oxides Emission Reduction Program	76.1, 76.2, 76.3, 76.4, 76.5, 76.7, 76.8, 76.9, 76.11, 76.13, 76.14, 76.15, Appendix A, Appendix B
40 CFR 77	Excess Emissions	77.1, 77.2, 77.3, 77.4, 77.5, 77.6
40 CFR 78	Appeals Procedures for Acid Rain Program	78.1, 78.2, 78.3, 78.4, 78.5, 78.6, 78.8, 78.9, 78.10, 78.11, 78.13, 78.14, 78.15, 78.16, 78.17, 78.18, 78.19, 78.20
40 CFR 63, Subpart UUUUU	National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units (EGU MACT)	63.9980 through 63.10042

DISTRICT ONLY ENFORCEABLE REGULATIONS		
Regulation	**Title**	**Applicable Sections**
5.00	Definitions	1, 2
5.01	General Provisions	1 through 2
5.02	Adoption of National Emission Standards for Hazardous Air Pollutants	1, 3.95 and 4
5.14	Hazardous Air Pollutants and Source Categories	1, 2
5.20	Methodology for Determining Benchmark Ambient Concentration of a Toxic Air Contaminant	1 through 6
5.21	Environmental Acceptability for Toxic Air Contaminants	1 through 5
5.22	Procedures for Determining the Maximum Ambient Concentration of a Toxic Air Contaminant	1 through 5
5.23	Categories of Toxic Air Contaminants	1 through 6

U1 Equipment:

Emission Point	Description	Applicable Regulation	Control ID	Stack ID
E1	One (1) tangentially fired boiler, rated capacity 3,085 MMBtu/hr, make Combustion Engineering, using pulverized coal as a primary fuel and natural gas as secondary fuel.	5.00, 5.01, 5.02, 5.14, 5.20, 5.21, 5.22, 5.23, 6.02, 6.07, 6.42, 6.47, 40 CFR 64, 40 CFR 72-73, 40 CFR 75-78, 40 CFR 63, UUUUU	C1, C2[a]	S1[a]
			C1, C26[b], C27[b]	S33[b]
E2	Four (4) coal silos, make Fisher-Klosterman, controlled by a centrifugal dust collector and equipped with four (4) coal mills, make Combustion Engineering Raymond Bowl Mills.	5.00, 5.01, 5.14, 5.20, 5.21, 5.22, 5.23, 6.09	C3	S5
Note a: The existing FGD (C2, S1) will shut down prior to April 16, 2016, which is the compliance date when this unit has to comply with 40 CFR 63, Subpart UUUUU. Note b: The new FGD and HAP PM control (C26, C27, and S33) will replace C2 and S1. These new control devices need to be in full operation no later than April 16, 2016, which is the compliance date when this unit has to comply with 40 CFR 63, Subpart UUUUU.[5]				

[5] On June 3, 2015, LG&E submitted a notification for initial startup of PJFF (C26) and FGD (C27) for U1. These control devices went into service on May 27, 2015.

U1 Control Devices:

Prior to compliance with 40 CFR 63, Subpart UUUUU, Unit 1 has following control devices:

ID	Description	Performance Indicator	Stack ID
C1	One (1) custom-built electrostatic precipitator (ESP) for PM control, make Western Precipitator Division	PM emission data from PM CEMS (if PM CEMS is not used to demonstrate compliance)	S1
C2	One (1) Flue Gas Desulfurization (FGD) unit for SO_2 control using limestone scrubbing liquor, make Combustion Engineering	N/A[6]	
C3	One (1) centrifugal dust collector, make Fisher-Klosterman	N/A[7]	S5

After compliance with 40 CFR 63, Subpart UUUUU, Unit 1 has following control devices:

ID	Description	Performance Indicator	Stack ID
C1	One (1) custom-built electrostatic precipitator (ESP) for PM control, make Western Precipitator Division	N/A[6]	S33
C26	One (1) HAP particulate matter control system, consists of: one (1) powdered activated carbon (PAC) injection system; one (1) dry sorbent injection system; liquid additive system(s); and one (1) pulse-jet fabric filter (PJFF) baghouse used for collecting PM from the boiler and PAC and dry sorbent injection system. PJFF baghouse make Clyde Bergemann Power Group, model Structural Pulse Jet	PM Control: PM emission data from PM CEMS (if PM CEMS is not used to demonstrate compliance) Hg control: (1) Minimum PAC injection rate;[8] (2) pH of reactant in FGD, 4.8-6.4; (3) Hg emission data from Sorbent Traps	
C27	One (1) combined Flue Gas desulfurization (FGD) unit for SO_2 control using limestone scrubbing liquor, make Babcock Power Environmental	N/A[6]	

[6] This unit is equipped with CEMS for NOx, SO2, and PM. According to the District's letter dated November 1, 2005, parametric monitoring of the ESP, FGD, and PJFF for this unit is removed as such monitoring would no longer be required for demonstration of compliance. On July 22, 2016, LG&E reported the normal pressure drop range for U1 PJFF, 2 – 6 inches of water, established during 90 consecutive operating days.

[7] For the coal silos (E2), the owner or operator has shown, by worst-case calculations without allowance for a control device, that the hourly uncontrolled PM emission standard cannot be exceeded; therefore, no additional monitoring, recordkeeping, or reporting is required to demonstrate compliance with the applicable PM standards specified in Regulation 6.09 is required for this emission point.

[8] In a letter dated October 4, 2016, LG&E demonstrated that in certain circumstance EGUs at this plant can meet the MACT mercury standard at zero PAC injection rate. Therefore the source is allowed to use flexible mercury control measures, including PAC injection or liquid additive system, to achieve compliance with MACT mercury standard.

ID	Description	Performance Indicator	Stack ID
C3	One (1) centrifugal dust collector, make Fisher-Klosterman	N/A[7]	S5

U1 Specific Conditions

S1. **Standards**[9] (Regulation 2.16, section 4.1.1)

a. **NO_x**

i. The owner or operator shall not allow the average NO_x emissions to exceed the alternate contemporaneous emission limitation of 0.40 lb/MMBtu of heat input on an annual average basis, as specified in Acid Rain Permit No.176-97-AR (R4) which is attached and considered part of the Title V Operating Permit. (Regulation 6.47, section 3.5 referencing 40 CFR Part 76)

ii. The owner or operator shall not exceed the NOx RACT emissions standard of 0.47 lb/MMBtu of heat input based on a rolling 30-day average. (See NOx RACT, Attachment D) (Regulation 6.42, section 4.3)

iii. The owner or operator shall install, maintain, calibrate and operate a continuous emission monitoring system (CEMS) for the measurement or calculation of nitrogen oxides in the flue gas. (Regulation 6.02, section 6.1.3) (NO_x RACT Plan) (Regulation 6.47, section 3.4 referencing 40 CFR 75.10(a)(2))

b. **SO_2**

i. The owner or operator shall not exceed 1.2 lb/MMBtu per hour heat input based on a three hour rolling average. (Regulation 6.07, section 4.1)

ii. The owner or operator shall comply with the SO_2 emission allowances specified in Acid Rain Permit No.176-97-AR (R4). (See Acid Rain Permit Attachment) (Regulation 6.47, section 3.2 referencing 40 CFR Part 73)

iii. The owner or operator shall operate and maintain the FGD, as recommended by the manufacturer, at all times the respective boiler is in normal operation, including periods of startup, shutdown, and malfunction, in a manner consistent with good air pollution control practice to meet the standards. [10] (Regulation 2.16, section 4.1.1)

iv. The owner or operator shall install, maintain, calibrate and operate a continuous emission monitoring system (CEMS) for the measurement of

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[9] The emission standards, monitoring, record keeping, and reporting requirements only apply to the boiler E1 (not the coal silos E2) if not indicated.

[10] The SO2 emissions cannot meet the standards uncontrolled. The owner or operator is required to operate the control devices to meet the applicable limits for SO2.

sulfur dioxide in the flue gas. (Regulation 6.02, section 6.1.2) (Regulation 6.47, section 3.4 referencing 40 CFR 75.10(a)(1))

c. **PM**

i. The owner or operator shall not exceed an allowable particulate emission rate of 0.11 lbs/MMBtu heat input based on a three hour rolling average. (Regulation 6.07, section 3.1)

ii. The owner or operator shall operate and maintain the PM control devices, as recommended by the manufacturer, at all times the respective boiler is in operation, including periods of startup, shutdown, and malfunction, in a manner consistent with good air pollution control practice to meet the standards. Following commissioning of the PJFF baghouses, the owner or operator may elect to operate, turn down, or turn off the ESP to ensure the efficient operation of the PJFF baghouse.[11] (Regulation 2.16, section 4.1.1)

iii. The company shall follow one of the two options below to demonstrate compliance with PM standards:

Compliance Options	PM	Opacity	Control Device Performance indication
Option 1	Certified PM CEMS	VE/Method 9, or Certified COMS	N/A
Option 2	Annual testing	Certified COMS	PM CEMS

iv. For coal silos (E2), the owner or operator shall not exceed an allowable particulate emission rate of 82.95 lbs/hr from four coal silos combined based on actual operating hours in a calendar day.[12] (Regulation 6.09, section 3.2)

d. **Opacity**

i. The owner or operator shall not cause the emission into the open air of particulate matter from any indirect heat exchanger which is greater than 20% opacity, except emissions into the open air of particulate matter from any indirect heat exchanger during building a new fire, cleaning the fire box, or blowing soot for a period or periods aggregating not more than ten

[11] The PM emissions cannot meet the standards uncontrolled. The owner or operator is required to operate the control devices to meet the applicable limits for PM.

[12] For the coal silos (E2), the owner or operator has shown, by worst-case calculations without allowance for a control device, that the hourly uncontrolled PM emission standard cannot be exceeded; therefore, no additional monitoring, recordkeeping, or reporting is required to demonstrate compliance with the applicable PM standards specified in Regulation 6.09 is required for this emission point.

minutes in any 60 minutes which are less than 40% opacity. (Regulation 6.07, section 3.2 and 3.3)

ii. The company shall follow one of the two options in the table under Specific Condition S1.c.iii to demonstrate compliance with opacity standards.

iii. For the coal silos (E2), the owner or operator shall not allow visible emissions to equal or exceed 20% opacity. (Regulation 6.09, section 3.1)

e. **TAC**

i. The owner or operator shall not allow TAC emissions from boiler E1 to exceed the TAC emission standards determined based upon the EA Demonstration provided to the District.[13] (Regulation 5.21, section 4.2 and section 4.3) (See Comment 1)

TAC Name	CAS #	TAC Limits Determination (lbs/yr)	Basis of Limits
Naphthalene	91-20-3	16.6	Controlled PTE
Formaldehyde	50-00-0	70.3	Controlled PTE
Hydrogen fluoride	7664-39-3	13,385	Controlled PTE
Arsenic compounds	7440-38-2	266	Controlled PTE
Cadmium compounds	7440-43-9	42.1	Controlled PTE
Chromium VI	7440-47-3	94.5	Controlled PTE
Chromium III	16065-83-1	216	Controlled PTE
Cobalt compounds	7440-48-4	56.2	Controlled PTE
Lead compounds	7439-92-1	332	Controlled PTE
Manganese compounds	7439-96-5	424	Controlled PTE
Nickel compounds	7440-02-0	307	Controlled PTE
Sulfuric acid	7664-93-9	118,679	Controlled PTE
Benzene	71-43-2	De minimis values (See Comment 1)	De Minimis
Bromoform	75-25-2		De Minimis
Chloroform	67-66-3		De Minimis
Methylene chloride	75-09-2		De Minimis
Tetrachloroethylene (Perc)	127-18-4		De Minimis
Toluene	108-88-3		De Minimis
Xylene	1330-20-7		De Minimis
Hydrochloric acid	7647-01-0		De Minimis

ii. See Plantwide Requirements S1.b.

[13] This table for TAC emission standards has been revised to exclude Category 3 and 4 TACs for existing sources and use “de minimis values”, instead of actual numbers for current de minimis levels, as emission standards.

f. **HAP** (40 CFR 63, Subpart UUUUU)

The owner or operator shall comply with 40 CFR 63, Subpart UUUUU (See Attachment A) no later than April 16, 2016.[14]

g. **BART** (40 CFR 52, Subpart S)

The owner or operator shall continue to utilize PJFF baghouse and/or existing ESP to control PM emissions for this unit.[15] (40 CFR 52.920(e) refer to Kentucky Regional Haze SIP)

S2. **Monitoring and Record Keeping** (Regulation 2.16, sections 4.1.9.1 and 4.1.9.2)

The owner or operator shall maintain the following records for a minimum of 5 years and make the records readily available to the District upon request.

a. **NO_x**

i. The owner or operator shall demonstrate compliance with NO_x RACT Plan limits by continuous emissions monitors (CEMs) as specified in the NO_x RACT Plan. (See NO_x RACT Attachment) (Regulation 6.42, section 4.3)

ii. The owner or operator shall keep a record identifying all deviations from the requirements of the NO_x RACT Plan.

iii. The owner or operator shall comply with the NO_x compliance plan requirements specified in the attached Acid Rain Permit, No.176-97-AR (R4). These record keeping requirements shall be determined in accordance with the Title IV Phase II Acid Rain Permit and are specified in 40 CFR Part 75 Subpart F. (See Appendix A to NOx RACT Plan) (Regulation 6.47, section 3.4 and 3.5 referencing 40 CFR Parts 75 and 76)

iv. The owner or operator shall record on an hourly basis all NO_x emission data specified in 40 CFR Part 75, section 75.57(d). For each NO_x emission rate (in lb/mmBtu) measured by a NO_x-diluent monitoring system, or, if applicable, for each NO_x concentration (in ppm) measured by a NO_x concentration monitoring system used to calculate NO_x mass emissions under 40 CFR 75.71(a)(2), record the following data as measured and

[14] According to 40 CFR 63.9984(b), compliance date for an existing EGU is April 16, 2015. LG&E requested a year extension and the District has approved the request for the extension per (40 CFR 63.6(i)(4)(i)). Therefore the compliance date for the EGUs under this construction is April 16, 2016.

[15] On March 30, 2012, EPA finalized a limited approval and a limited disapproval of the Kentucky state implementation plan submitted on June 25, 2008 and May 28, 2010. According to 40 CFR 52.920(e), the owner or operator shall meet BART requirements summarized in Table 7.5.3-2 of the Commonwealth's May 28, 2010 submittal.

reported from the certified primary monitor, certified back-up monitor, or other approved method of emissions determination:

1) Component-system identification code, as provided in 40 CFR 75.53 (including identification code for the moisture monitoring system, if applicable); (40 CFR 75.57(d)(1))

2) Date and hour; (40 CFR 75.57(d)(2))

3) Hourly average NO_x concentration (ppm, rounded to the nearest tenth) and hourly average NO_x concentration (ppm, rounded to the nearest tenth) adjusted for bias if bias adjustment factor required, as provided in 40 CFR 75.24(d); (40 CFR 75.57(d)(3))

4) Hourly average diluent gas concentration (for NO_x -diluent monitoring systems, only, in units of percent O_2 or percent CO_2, rounded to the nearest tenth); (40 CFR 75.57(d)(4))

5) If applicable, the hourly average moisture content of the stack gas (percent H_2O, rounded to the nearest tenth). If the continuous moisture monitoring system consists of wet- and dry-basis oxygen analyzers, also record both the hourly wet- and dry-basis oxygen readings (in percent O2, rounded to the nearest tenth); (40 CFR 75.57(d)(5))

6) Hourly average NO_x emission rate (for NO_x -diluent monitoring systems only, in units of lb/mmBtu, rounded to the nearest thousandth); (40 CFR 75.57(d)(6))

7) Hourly average NO_x emission rate (for NO_x -diluent monitoring systems only, in units of lb/mmBtu, rounded to the nearest thousandth), adjusted for bias if bias adjustment factor is required, as provided in 40 CFR 75.24(d). The requirement to report hourly NO_x emission rates to the nearest thousandth shall not affect NO_x compliance determinations under part 76 of this chapter; compliance with each applicable emission limit under part 76 shall be determined to the nearest hundredth pound per million Btu; (40 CFR 75.57(d)(7))

8) Percent monitoring system data availability (recorded to the nearest tenth of a percent), for the NO_x -diluent or NO_x concentration monitoring system, and, if applicable, for the moisture monitoring system, calculated pursuant to 40 CFR 75.32; (40 CFR 75.57(d)(8))

9) Method of determination for hourly average NO_x emission rate or NO_x concentration and (if applicable) for the hourly average

moisture percentage, using Codes 1–55 in Table 4a of 40 CFR 75.57; and (40 CFR 75.57(d)(9))

10) Identification codes for emissions formulas used to derive hourly average NO_x emission rate and total NO_x mass emissions, as provided in 40 CFR 75.53, and (if applicable) the F-factor used to convert NO_x concentrations into emission rates. (40 CFR 75.57(d)(10))

v. A CEMS for measuring either oxygen (O_2) or carbon dioxide (CO_2) in the flue gases shall be installed, calibrated, maintained, and operated by the owner or operator. (Regulation 6.02, section 6.1.3) (NO_x RACT Plan)

vi. The owner or operator shall monitor the NO_x emissions, the NO_x allowances, as specified in the Clean Air Interstate Rule or the applicable NO_x cap and trade program(s) in effect.

vii. The owner or operator shall comply with the following in order to demonstrate compliance with the emission standard as required by 40 CFR 52: For performance evaluations under 40 CFR 60.13(c) and calibration checks under 40 CFR 60.13(d), the following procedures shall be used:

1) Methods 6, 7, and 3B of appendix A of this part, as applicable, shall be used for the performance evaluations of SO_2 and NO_X continuous monitoring systems. Acceptable alternative methods for Methods 6, 7, and 3B of appendix A of this part are given in 40 CFR 60.46(d).

2) Sulfur dioxide or nitric oxide, as applicable, shall be used for preparing calibration gas mixtures under Performance Specification 2 of appendix B to this part.

3) For affected facilities burning fossil fuel(s), the span value for a continuous monitoring system measuring the opacity of emissions shall be 80, 90, or 100 percent. For a continuous monitoring system measuring sulfur oxides or NO_X the span value shall be determined using one of the following procedures:

(a) Except as provided under paragraph 40 CFR 60.45(c)(3)(ii), SO_2 and NO_X span values shall be determined as follows:

Fossil fuel	In parts per million	
	Span value for SO_2	Span value for NO_X
Gas	Not Applicable	500.
Liquid	1,000	500.
Solid	1,500	1,000.

(b) As an alternative to meeting the requirements of paragraph 40 CFR 60.45(c)(3)(i), the owner or operator of an affected facility may elect to use the SO_2 and NO_X span values determined according to sections 2.1.1 and 2.1.2 in appendix A to part 75 of this chapter.

viii. The owner or operator shall comply with the following in order to demonstrate compliance with the emission standard as required by 40 CFR 52: The conversion procedures in 40 CFR 60.45(e) and (f) shall be used to convert the continuous monitoring data into units of the applicable standards.

1) For any CEMS installed under paragraph (a) of this section, the following conversion procedures shall be used to convert the continuous monitoring data into units of the applicable standards (ng/J, lb/MMBtu):

(a) When a CEMS for measuring O_2 is selected, the measurement of the pollutant concentration and O_2 concentration shall each be on a consistent basis (wet or dry). Alternative procedures approved by the Administrator shall be used when measurements are on a wet basis. When measurements are on a dry basis, the following conversion procedure shall be used:

$$E = CF\left(\frac{20.9}{(20.9 - \%O_2)}\right)$$

Where E, C, F, and $\%O_2$ are determined under paragraph (f) of this section.

(b) When a CEMS for measuring CO_2 is selected, the measurement of the pollutant concentration and CO_2 concentration shall each be on a consistent basis (wet or dry) and the following conversion procedure shall be used:

$$E = CF_c\left(\frac{100}{\%CO_2}\right)$$

Where E, C, F_c and $\%CO_2$ are determined under paragraph (f) of this section.

2) The values used in the equations under paragraphs (e)(1) and (2) of this section are derived as follows:

(a) E = pollutant emissions, ng/J (lb/MMBtu).

(b) C = pollutant concentration, ng/dscm (lb/dscf), determined by multiplying the average concentration (ppm) for each one-hour period by 4.15×10^{4} M ng/dscm per ppm (2.59×10^{-9}M lb/dscf per ppm) where M = pollutant molecular weight, g/g-mole (lb/lb-mole). M = 64.07 for SO_2 and 46.01 for NO_X.

(c) $\%O_2$, $\%CO_2$= O_2 or CO_2 volume (expressed as percent), determined with equipment specified under paragraph (a) of this section.

(d) F, F_c= a factor representing a ratio of the volume of dry flue gases generated to the calorific value of the fuel combusted (F), and a factor representing a ratio of the volume of CO_2 generated to the calorific value of the fuel combusted (F_c), respectively. Values of F and F_c are given as follows:

(i) For anthracite coal as classified according to ASTM D388 (incorporated by reference, see 40 CFR 60.17), F = $2{,}723 \times 10^{-17}$ dscm/J (10,140 dscf/MMBtu) and F_c= 0.532×10^{-17} scm CO_2/J (1,980 scf CO_2/MMBtu).

(ii) For subbituminous and bituminous coal as classified according to ASTM D388 (incorporated by reference, see 40 CFR 60.17), F = 2.637×10^{-7} dscm/J (9,820 dscf/MMBtu) and F_c= 0.486×10^{-7} scm CO_2/J (1,810 scf CO_2/MMBtu).

(iii) For liquid fossil fuels including crude, residual, and distillate oils, F = 2.476×10^{-7} dscm/J (9,220 dscf/MMBtu) and F_c= 0.384×10^{-7} scm CO_2/J (1,430 scf CO_2/MMBtu).

(iv) For gaseous fossil fuels, F = 2.347×10^{-7} dscm/J (8,740 dscf/MMBtu). For natural gas, propane, and butane fuels, F_c= 0.279×10^{-7} scm CO_2/J (1,040 scf CO_2/MMBtu) for natural gas, 0.322×10^{-7} scm CO_2/J (1,200 scf CO_2/MMBtu) for propane, and 0.338×10^{-7} scm CO_2/J (1,260 scf CO_2/MMBtu) for butane.

(v) For bark F = 2.589×10^{-7} dscm/J (9,640 dscf/MMBtu) and F_c= 0.500×10^{-7} scm CO_2/J (1,840 scf CO_2/MMBtu). For wood residue other than bark F = 2.492×10^{-7} dscm/J (9,280 dscf/MMBtu) and F_c= 0.494×10^{-7} scm CO_2/J (1,860 scf CO_2/MMBtu).

(vi) For lignite coal as classified according to ASTM D388 (incorporated by reference, see 40 CFR 60.17), F = 2.659 × 10 $^{-7}$ dscm/J (9,900 dscf/MMBtu) and F_c= 0.516 × 10 $^{-7}$ scm CO_2/J (1,920 scf CO_2/MMBtu).

(e) The owner or operator may use the following equation to determine an F factor (dscm/J or dscf/MMBtu) on a dry basis (if it is desired to calculate F on a wet basis, consult the Administrator) or Fc factor (scm CO_2/J, or scf CO_2/MMBtu) on either basis in lieu of the F or F_c factors specified in paragraph (f)(4) of this section:

$$F = 10^{-6} \frac{[227.2\ (\%H) + 95.5\ (\%C) + 35.6\ (\%S) + 8.7\ (\%N) - 28.7\ (\%O)]}{GCV}$$

$$F_c = \frac{2.0 \times 10^{-5}\ (\%C)}{GCV\ (SI\ units)}$$

$$F = 10^{-6} \frac{[3.64\ (\%H) + 1.53\ (\%C) + 0.57\ (\%S) + 0.14\ (\%N) - 0.46\ (\%O)]}{GCV\ (English\ units)}$$

$$F_c = \frac{20.0\ (\%C)}{GCV\ (SI\ units)}$$

$$F_c = \frac{321 \times 10^{3}\ (\%C)}{GCV\ (English\ units)}$$

(i) %H, %C, %S, %N, and %O are content by weight of hydrogen, carbon, sulfur, nitrogen, and O_2(expressed as percent), respectively, as determined on the same basis as GCV by ultimate analysis of the fuel fired, using ASTM D3178 or D3176 (solid fuels), or computed from results using ASTM D1137, D1945, or D1946 (gaseous fuels) as applicable. (These five methods are incorporated by reference, see 40 CFR 60.17.)

(ii) GVC is the gross calorific value (kJ/kg, Btu/lb) of the fuel combusted determined by the ASTM test methods D2015 or D5865 for solid fuels and D1826 for gaseous fuels as applicable. (These three methods are incorporated by reference, see 40 CFR 60.17.)

(iii) For affected facilities which fire both fossil fuels and nonfossil fuels, the F or Fc value shall be subject to the Administrator's approval.

(f) For affected facilities firing combinations of fossil fuels or fossil fuels and wood residue, the F or Fc factors determined by paragraphs (f)(4) or (f)(5) of this section shall be prorated in accordance with the applicable formula as follows:

$$F = \sum_{i=1}^{n} X_i F_i \quad \text{or} \quad F_c = \sum_{i=1}^{n} X_i (F_c)_i$$

Where:
X_i= Fraction of total heat input derived from each type of fuel (e.g. natural gas, bituminous coal, wood residue, etc.);
F_i or $(F_c)_i$= Applicable F or F_c factor for each fuel type determined in accordance with paragraphs (f)(4) and (f)(5) of this section; and
n = Number of fuels being burned in combination.

b. **SO_2**

i. The owner or operator shall maintain hourly records of SO_2 emissions as specified in Regulation 6.02, section 6.1.2.

ii. The owner or operator shall record on an hourly basis all SO_2 emission data specified in 40 CFR 75.57(c):

1) For SO_2 concentration during unit operation, as measured and reported from each certified primary monitor, certified back-up monitor, or other approved method of emissions determination: (40 CFR 75.57(c)(1))

(a) Component-system identification code, as provided in 40 CFR 75.53; (40 CFR 75.57(c)(1)(i))

(b) Date and hour; (40 CFR 75.57(c)(1)(ii))

(c) Hourly average SO_2 concentration (ppm, rounded to the nearest tenth); (40 CFR 75.57(c)(1)(iii))

(d) Hourly average SO_2 concentration (ppm, rounded to the nearest tenth), adjusted for bias if bias adjustment factor is required, as provided in 40 CFR 75.24(d); (40 CFR 75.57(c)(1)(iv))

(e) Percent monitor data availability (recorded to the nearest tenth of a percent), calculated pursuant to 40 CFR 75.32; and (40 CFR 75.57(c)(1)(v))

(f) Method of determination for hourly average SO_2 concentration using Codes 1–55 in Table 4a of 40 CFR 75.57. (40 CFR 75.57(c)(1)(vi))

2) For flow rate during unit operation, as measured and reported from each certified primary monitor, certified back-up monitor, or other approved method of emissions determination: (40 CFR 75.57(c)(2))

(a) Component-system identification code, as provided in 40 CFR 75.53; (40 CFR 75.57(c)(2)(i))

(b) Date and hour; (40 CFR 75.57(c)(2)(ii))

(c) Hourly average volumetric flow rate (in scfh, rounded to the nearest thousand); (40 CFR 75.57(c)(2)(iii))

(d) Hourly average volumetric flow rate (in scfh, rounded to the nearest thousand), adjusted for bias if bias adjustment factor required, as provided in 40 CFR 75.24(d); (40 CFR 75.57(c)(2)(iv))

(e) Percent monitor data availability (recorded to the nearest tenth of a percent) for the flow monitor, calculated pursuant to 40 CFR 75.32; and (40 CFR 75.57(c)(2)(v))

(f) Method of determination for hourly average flow rate using Codes 1–55 in Table 4a of 40 CFR 75.57. (40 CFR 75.57(c)(2)(vi))

3) For SO_2 mass emission rate during unit operation, as measured and reported from the certified primary monitoring system(s), certified redundant or non-redundant back-up monitoring system(s), or other approved method(s) of emissions determination: (40 CFR 75.57(c)(4))

(a) Date and hour; (40 CFR 75.57(c)(4)(i))

(b) Hourly SO_2 mass emission rate (lb/hr, rounded to the nearest tenth); (40 CFR 75.57(c)(4)(ii))

(c) Hourly SO_2 mass emission rate (lb/hr, rounded to the nearest tenth), adjusted for bias if bias adjustment factor required, as provided in 40 CFR 75.24(d); and (40 CFR 75.57(c)(4)(iii))

(d) Identification code for emissions formula used to derive hourly SO2 mass emission rate from SO2 concentration and flow and (if applicable) moisture data in paragraphs (c)(1), (c)(2), and (c)(3) of 40 CFR 75.57, as provided in 40 CFR 75.53. (40 CFR 75.57(c)(4)(iv))

iii. The owner or operator shall comply with the following in order to demonstrate compliance with the emission standard as required by 40 CFR 52: For performance evaluations under 40 CFR 60.13(c) and calibration checks under 40 CFR 60.13(d), the following procedures shall be used:

1) Methods 6, 7, and 3B of appendix A of this part, as applicable, shall be used for the performance evaluations of SO_2 and NO_X continuous monitoring systems. Acceptable alternative methods for Methods 6, 7, and 3B of appendix A of this part are given in 40 CFR 60.46(d).

2) Sulfur dioxide or nitric oxide, as applicable, shall be used for preparing calibration gas mixtures under Performance Specification 2 of appendix B to this part.

3) For affected facilities burning fossil fuel(s), the span value for a continuous monitoring system measuring the opacity of emissions shall be 80, 90, or 100 percent. For a continuous monitoring system measuring sulfur oxides or NO_X the span value shall be determined using one of the following procedures:

(a) Except as provided under paragraph 40 CFR 60.45(c)(3)(ii), SO_2 and NO_X span values shall be determined as follows:

Fossil fuel	In parts per million	
	Span value for SO_2	Span value for NO_X
Gas	Not Applicable	500.
Liquid	1,000	500.
Solid	1,500	1,000.

(b) As an alternative to meeting the requirements of paragraph 40 CFR 60.45(c)(3)(i), the owner or operator of an affected facility may elect to use the SO_2 and NO_X span values determined according to sections 2.1.1 and 2.1.2 in appendix A to part 75 of this chapter.

iv. The owner or operator shall comply with the following in order to demonstrate compliance with the emission standard as required by 40 CFR 52: The conversion procedures in 40 CFR 60.45(e) and (f) shall be used to convert the continuous monitoring data into units of the applicable standards.

1) For any CEMS installed under paragraph (a) of this section, the following conversion procedures shall be used to convert the

continuous monitoring data into units of the applicable standards (ng/J, lb/MMBtu):

(a) When a CEMS for measuring O_2 is selected, the measurement of the pollutant concentration and O_2 concentration shall each be on a consistent basis (wet or dry). Alternative procedures approved by the Administrator shall be used when measurements are on a wet basis. When measurements are on a dry basis, the following conversion procedure shall be used:

$$E = CF\left(\frac{20.9}{(20.9 - \%O_2)}\right)$$

Where E, C, F, and $\%O_2$ are determined under paragraph (f) of this section.

(b) When a CEMS for measuring CO_2 is selected, the measurement of the pollutant concentration and CO_2 concentration shall each be on a consistent basis (wet or dry) and the following conversion procedure shall be used:

$$E = CF_c\left(\frac{100}{\%CO_2}\right)$$

Where E, C, F_c and $\%CO_2$ are determined under paragraph (f) of this section.

2) The values used in the equations under paragraphs (e)(1) and (2) of this section are derived as follows:

(a) E = pollutant emissions, ng/J (lb/MMBtu).

(b) C = pollutant concentration, ng/dscm (lb/dscf), determined by multiplying the average concentration (ppm) for each one-hour period by 4.15×10^{4} M ng/dscm per ppm (2.59×10^{-9}M lb/dscf per ppm) where M = pollutant molecular weight, g/g-mole (lb/lb-mole). M = 64.07 for SO_2 and 46.01 for NO_X.

(c) $\%O_2$, $\%CO_2$= O_2 or CO_2 volume (expressed as percent), determined with equipment specified under paragraph (a) of this section.

(d) F, F_c= a factor representing a ratio of the volume of dry flue gases generated to the calorific value of the fuel combusted

(F), and a factor representing a ratio of the volume of CO_2 generated to the calorific value of the fuel combusted (F_c), respectively. Values of F and F_c are given as follows:

(i) For anthracite coal as classified according to ASTM D388 (incorporated by reference, see 40 CFR 60.17), F = 2,723 × 10 $^{-17}$ dscm/J (10,140 dscf/MMBtu) and F_c= 0.532 × 10 $^{-17}$ scm CO_2/J (1,980 scf CO_2/MMBtu).

(ii) For subbituminous and bituminous coal as classified according to ASTM D388 (incorporated by reference, see 40 CFR 60.17), F = 2.637 × 10 $^{-7}$ dscm/J (9,820 dscf/MMBtu) and F_c= 0.486 × 10 $^{-7}$ scm CO_2/J (1,810 scf CO_2/MMBtu).

(iii) For liquid fossil fuels including crude, residual, and distillate oils, F = 2.476 × 10 $^{-7}$ dscm/J (9,220 dscf/MMBtu) and F_c= 0.384 × 10 $^{-7}$ scm CO_2/J (1,430 scf CO_2/MMBtu).

(iv) For gaseous fossil fuels, F = 2.347 × 10 $^{-7}$ dscm/J (8,740 dscf/MMBtu). For natural gas, propane, and butane fuels, F_c= 0.279 × 10 $^{-7}$ scm CO_2/J (1,040 scf CO_2/MMBtu) for natural gas, 0.322 × 10 $^{-7}$ scm CO_2/J (1,200 scf CO_2/MMBtu) for propane, and 0.338 × 10 $^{-7}$ scm CO_2/J (1,260 scf CO_2/MMBtu) for butane.

(v) For bark F = 2.589 × 10 $^{-7}$ dscm/J (9,640 dscf/MMBtu) and F_c= 0.500 × 10 $^{-7}$ scm CO_2/J (1,840 scf CO_2/MMBtu). For wood residue other than bark F = 2.492 × 10 $^{-7}$ dscm/J (9,280 dscf/MMBtu) and F_c= 0.494 × 10 $^{-7}$ scm CO_2/J (1,860 scf CO_2/MMBtu).

(vi) For lignite coal as classified according to ASTM D388 (incorporated by reference, see 40 CFR 60.17), F = 2.659 × 10 $^{-7}$ dscm/J (9,900 dscf/MMBtu) and F_c= 0.516 × 10 $^{-7}$ scm CO_2/J (1,920 scf CO_2/MMBtu).

(e) The owner or operator may use the following equation to determine an F factor (dscm/J or dscf/MMBtu) on a dry basis (if it is desired to calculate F on a wet basis, consult the Administrator) or Fc factor (scm CO_2/J, or scf CO_2/MMBtu) on either basis in lieu of the F or F_c factors specified in paragraph (f)(4) of this section:

$$F = 10^{-6}\frac{[227.2\ (\%H) + 95.5\ (\%C) + 35.6\ (\%S) + 8.7\ (\%N) - 28.7\ (\%O)]}{GCV}$$

$$F_c = \frac{2.0\times10^{-5}\ (\%C)}{GCV\ (SI\ units)}$$

$$F = 10^{-6}\frac{[3.64\ (\%H) + 1.53\ (\%C) + 0.57\ (\%S) + 0.14\ (\%N) - 0.46\ (\%O)]}{GCV\ (English\ units)}$$

$$F_c = \frac{20.0\ (\%C)}{GCV\ (SI\ units)}$$

$$F_c = \frac{321\times10^{3}\ (\%C)}{GCV\ (English\ units)}$$

(i) %H, %C, %S, %N, and %O are content by weight of hydrogen, carbon, sulfur, nitrogen, and O_2(expressed as percent), respectively, as determined on the same basis as GCV by ultimate analysis of the fuel fired, using ASTM D3178 or D3176 (solid fuels), or computed from results using ASTM D1137, D1945, or D1946 (gaseous fuels) as applicable. (These five methods are incorporated by reference, see 40 CFR 60.17.)

(ii) GVC is the gross calorific value (kJ/kg, Btu/lb) of the fuel combusted determined by the ASTM test methods D2015 or D5865 for solid fuels and D1826 for gaseous fuels as applicable. (These three methods are incorporated by reference, see 40 CFR 60.17.)

(iii) For affected facilities which fire both fossil fuels and nonfossil fuels, the F or Fc value shall be subject to the Administrator's approval.

(f) For affected facilities firing combinations of fossil fuels or fossil fuels and wood residue, the F or Fc factors determined by paragraphs (f)(4) or (f)(5) of this section shall be prorated in accordance with the applicable formula as follows:

$$F = \sum_{i=1}^{n} X_i F_i \quad \text{or} \quad F_c = \sum_{i=1}^{n} X_i \left(F_c\right)_i$$

Where:
X_i= Fraction of total heat input derived from each type of fuel (e.g. natural gas, bituminous coal, wood residue, etc.);

F_i or $(F_c)_i$= Applicable F or F_c factor for each fuel type determined in accordance with paragraphs (f)(4) and (f)(5) of this section; and

n = Number of fuels being burned in combination.

c. **PM**

i. The company shall follow one of the two options below to demonstrate compliance with PM standards:

1) Option 1: the owner or operator shall install, maintain, calibrate, and operate a PM CEMS for each steam generating unit. [16,17] (Regulation 2.16, section 4.1.1) (40 CFR 64)

(a) The use of PM CEMS as the measurement technique must be appropriate for the stack conditions.

(b) The PM CEMS must be installed, operated and maintained in accordance with the manufacturer's recommendations.

(c) The PM CEMS must be certified in accordance with Performance Specification 11, Specifications and Test Procedures for Particulate Matter Continuous Emission Monitoring Systems at Stationary Sources, found in 40 CFR 60, Appendix B.

(d) A quality assurance/quality control program must be implemented in accordance with procedures in 40 CFR 60, Appendix F, Procedure 2 (Quality Assurance Requirements for Particulate Matter Continuous Emission Monitoring Systems at Stationary Sources).

(e) Compliance with the particulate matter emission limit will be based upon three-hour rolling average periods during source operation.

[16] According to LG&E's request, PM CEMS have been installed, calibrated, maintained, and operated for Unit 1. LG&E requested permission to remove COMS for Unit 3 and 4 under provisions in 40 CFR 60.13(i)(1), "Alternative monitoring requirements when installation of a continuous monitoring system or monitoring device specified by this part would not provide accurate measurements due to liquid water or other interferences caused by substances in the effluent gases." LG&E's proposal for Unit 3 and 4 was accepted in a letter from EPA dated Feb. 28, 2007. The District accordingly approved LG&E's request for removing COMS for Unit 1 and 2 providing PM CEMS are appropriately installed for these units.

[17] The coal-fired boilers are subject to 40 CFR Part 64 - Compliance Assurance Monitoring (CAM) for Major Stationary Source since SO2, PM, and NOx emissions from each of the boilers may be greater than the major source threshold and control devices are required to achieve compliance with standards. On 5/21/2014, LG&E submitted a revised CAM Plan in which SO2 and NOx CEMS are used for compliance demonstration. PM CEMS is used to demonstrate compliance or provide an indication of continuous PM control.

(f) Quarterly excess emission reports must be submitted, and PM excess emissions shall be reported based upon three-hour rolling averages during source operation.

2) Option 2: the owner or operator shall conduct an annual EPA Reference Method 5 performance test following the testing requirements in Attachment B, Specific Condition b.ii.

ii. If certified PM CEMS (Option 1) is used to demonstrate compliance with PM standards, the owner or operator shall record on an hourly basis all PM emission data, in lb/MMBtu, from PM CEMS.[18] (40 CFR 64)

iii. If annual PM testing (Option 2) is used to demonstrate compliance with PM standards, the owner or operator shall use PM CEMS as a performance indicator of continuous normal operation of the PM control devices and do the following:[18] (40 CFR 64)

1) The owner or operator shall monitor and record all PM emission data from PM CEMS, which is used as the indicator of normal operation of the PM control devices.

2) The owner or operator shall maintain daily records of any periods of time where the process was operating and the PM control devices were not operating or a declaration that the PM control devices operated at all times that day when the process was operating.

3) If there is any time that the PM control devices are bypassed or not in operation when the process is operating, then the owner or operator shall keep a record of the following for each bypass event:

(a) Date;
(b) Start time and stop time;
(c) Identification of the control devices and process equipment;
(d) PM emissions during the bypass in lb/hr;
(e) Summary of the cause or reason for each bypass event;
(f) Corrective action taken to minimize the extent or duration of the bypass event; and
(g) Measures implemented to prevent reoccurrence of the situation that resulted in the bypass event.

[18] The coal-fired boilers are subject to 40 CFR Part 64 - Compliance Assurance Monitoring (CAM) for Major Stationary Source since SO2, PM, and NOx emissions from each of the boilers may be greater than the major source threshold and control devices are required to achieve compliance with standards. On 5/21/2014, LG&E submitted a revised CAM Plan in which SO2 and NOx CEMS are used for compliance demonstration. PM CEMS is used to demonstrate compliance or provide an indication of continuous PM control.

d. **Opacity**

i. If certified COMS is used to demonstrate compliance with opacity standards, the owner or operator shall record on an hourly basis all opacity from COMS.[19]

ii. If VE/Method 9 is used to demonstrate compliance with opacity standards, in order for the owner or operator to use its VE observations to satisfy the opacity monitoring requirement, the following conditions must be met:[19] (EPA Letter, 2007)

1) On a weekly basis, the owner or operator shall attempt to perform VE observations in accordance with procedures in EPA Method 9.

2) On the weeks when it is possible to collect unit-specific VE data, at least one hour of Method 9 data shall be collected for each unit.

3) Records of the Method 9 readings shall be submitted with the quarterly excess emission reports for PM emissions.

iii. The owner or operator shall keep a record of every Method 9 test performed or the reason why it could not be performed that day.

iv. <u>For coal silos (E2):</u>

1) The owner or operator shall conduct a weekly one-minute visible emissions survey, during normal operation, of the PM Emission Points (stacks). For Emission Points without observed visible emissions during twelve consecutive operating weeks, the owner or operator may elect to conduct a monthly one-minute visible emission survey, during normal operation.

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[19] According to LG&E's request, PM CEMS have been installed, calibrated, maintained, and operated for Unit 1. LG&E requested permission to remove COMS for Unit 3 and 4 under provisions in 40 CFR 60.13(i)(1), "Alternative monitoring requirements when installation of a continuous monitoring system or monitoring device specified by this part would not provide accurate measurements due to liquid water or other interferences caused by substances in the effluent gases." LG&E's proposal for Unit 3 and 4 was accepted in a letter from EPA dated Feb. 28, 2007. The District accordingly approved LG&E's request for removing COMS for Unit 1 and 2 providing PM CEMS are appropriately installed for these units.

2) At Emission Points where visible emissions are observed, the owner or operator shall initiate corrective action within eight hours of the initial observation. If the visible emissions persist, the owner or operator shall perform or cause to be performed a Method 9 for stack emissions within 24 hours of the initial observation. If the opacity standard is exceeded, the owner or operator shall report the exceedance to the District, according to Regulation 1.07, and take all practicable steps to eliminate the exceedance.

3) The owner or operator shall maintain records, monthly, of the results of all visible emissions surveys and tests. Records of the results of any visible emissions survey shall include the date of the survey, the name of the person conducting the survey, whether or not visible emissions were observed, and what if any corrective action was performed. If an emission point is not being operated during a given month, then no visible emission survey needs to be performed and a negative declaration shall be entered in the record.

e. **TAC**

i. The owner or operator shall monthly calculate and record TAC emissions for this unit in order to demonstrate compliance with the TAC emission standards.

ii. See Plantwide Requirements S2.b.

f. **HAP** (40 CFR 63, Subpart UUUUU)

i. The owner or operator shall comply with 40 CFR 63, Subpart UUUUU (See Attachment A) no later than April 16, 2016.

ii. The owner or operator shall establish a site-specific minimum activated carbon injection rate for PAC injection system according to Attachment B, Specific Condition a.i.[20] The owner or operator shall monitor and record the activated carbon injection rate during each operating day.

iii. The owner or operator shall monitor and record all Hg emission data from the Hg sorbent traps, which is used as the indicator of normal operation of the Hg control measures.

iv. The owner or operator shall monitor and record the pH of the reactant material in the FGD and any other parameters verified as having a direct

[20] In a letter dated October 4, 2016, LG&E demonstrated that in certain circumstance EGUs at this plant can meet the MACT mercury standard at zero PAC injection rate. Therefore the source is allowed to use flexible mercury control measures, including PAC injection or liquid additive system, to achieve compliance with MACT mercury standard.

effect on Hg emissions during each operating day, which is (are) used as the indicator(s) of normal operation of Hg control measures.[21]

v. The owner or operator shall maintain records of which Hg control devices/measure was being used during each operating day.

g. **BART** (40 CFR 52, Subpart S)

The owner or operator shall maintain daily records of any periods of time where the process was operating and both PJFF baghouse and ESP were not operating or a declaration that the PJFF baghouse and/or ESP operated at all times that day when the process was operating.

S3. **Reporting** (Regulation 2.16, section 4.1.9.3)

The owner or operator shall submit quarterly compliance reports that include the information in this section.

a. **NO_x**

i. The owner or operator shall identify all periods of exceeding a NO_x emission standard during a quarterly reporting period. The quarterly compliance report shall include the following:

1) Emission Unit ID number and emission point ID number;
2) Identification of all periods during which a deviation occurred;
3) A description, including the magnitude, of the deviation;
4) If known, the cause of the deviation;
5) A description of all corrective actions taken to abate the deviation; and
6) If no deviations occur during a quarterly reporting period, the report shall contain a negative declaration.

ii. The owner or operator shall submit a written report of excess emissions and the nature and cause of the excess emissions if known. The averaging period used for data reporting should correspond to the averaging period specified in the emission test method used to determine compliance with an emission standard for the pollutant/source category in question. All quarterly reports shall be postmarked by the 30th day following the end of each calendar quarter. The required report shall include: (Regulation 6.02, section 16.1)

1) For gaseous measurements, the summary shall consist of hourly averages in the units of the applicable standard. The hourly averages

[21] LG&E has established normal pH range per monitoring records during consecutive 180 days. On 10/20/2016, LG&E reported that the normal pH range for this unit is 4.8 – 6.4.

shall not appear in the written summary, but shall be made available electronically.[22] (Regulation 6.02, section 16.3)

2) The data and time identifying each period during which the continuous monitoring system was inoperative, except for zero and span checks, and the nature of system repairs or adjustment shall be reported. Proof of continuous monitoring system performance whenever system repairs or adjustments have been made is required. (Regulation 6.02, section 16.4)

3) When no excess emissions have occurred and the continuous monitoring systems have been inoperative, repaired, or adjusted, such information shall be included in the report. (Regulation 6.02, section 16.5)

4) Owners or operators of affected facilities shall maintain a file of all information reported in the quarterly summaries, and all other data collected either by the continuous monitoring system or as necessary to convert monitoring data to the units of the applicable standard for a minimum of two years from the date of collection of such data or submission of such summaries. (Regulation 6.02, section 16.6)

iii. The owner or operator shall comply with the reporting requirements for the Acid Rain Permit No.176-97-AR (R4), specified in 40 CFR 75, Subpart G. Notifications, Monitoring Plans, Initial Certification and Recertification Applications, Quarterly Reports, Opacity Reports, Petitions to the Administrator[23], and Retired Unit Petitions shall be submitted as specified in Subpart G - reporting requirements. (See Attachment E)

iv. The owner or operator shall comply with the reporting requirements for the Title IV NO_x Budget Emission Limitation, 0.40 lb/MMBtu, as specified in 40 CFR Part 76.

v. Excess emissions for affected facilities using a CEMS for measuring NO_X are defined as: (Regulation 2.16, section 4.1.9.3)

1) Any annual average period during which the average emissions (arithmetic average of all one-hour period during the 12 month period) of NOx as measured by a CEMS exceed the applicable standard.

2) Any 30 operating day period during which the average emissions (arithmetic average of all one-hour periods during the 30 operating

[22] The hourly averages are only required to be made available in electronic summary, not in written summary.

[23] In this permit, Administrator means the District.

days) of NO_X as measured by a CEMS exceed the applicable standard.

b. **SO_2**

i. The owner or operator shall identify all periods of exceeding a SO_2 emission standard during a quarterly reporting period. The report shall include the following:

1) Emission Unit ID number and emission point ID number;
2) Identification of all periods during which a deviation occurred;
3) A description, including the magnitude, of the deviation;
4) If known, the cause of the deviation;
5) A description of all corrective actions taken to abate the deviation; and
6) If no deviations occur during a quarterly reporting period, the report shall contain a negative declaration.

ii. The owner or operator shall submit a written report of excess emissions and the nature and cause of the excess emissions if known. See Specific Condition S3.a.ii.

iii. The owner or operator shall comply with the reporting requirements for the Acid Rain Permit No.176-97-AR (R4), specified in 40 CFR 75, Subpart G. Notifications, monitoring Plans, Initial Certification and Recertification Applications, Quarterly Reports, Opacity Reports, Petitions to the Administrator, and Retired Unit Petitions shall be submitted as specified in Subpart G - Reporting Requirements. (See Attachment E)

iv. Excess emissions for affected facilities using a CEMS for measuring SO_2 are defined as: (Regulation 2.16, section 4.1.9.3)

1) Any three-hour period during which the average emissions (arithmetic average of three contiguous one-hour periods) of SO_2 as measured by a CEMS exceed the applicable standard; or

2) Any 30 operating day period during which the average emissions (arithmetic average of all one-hour periods during the 30 operating days) of SO_2 as measured by a CEMS exceed the applicable standard.

c. **PM**

i. The owner or operator shall identify all periods of exceeding a PM emission standard during a quarterly reporting period. The report shall include the following:

1) Emission Unit ID number and emission point ID number;
2) The date and duration (including the start and stop time) during which a deviation occurred;
3) The magnitude of excess emissions;
4) Description of the deviation and summary information on the cause or reason for excess emissions;
5) Corrective action taken to minimize the extent and duration of each excess emissions event;
6) Measures implemented to prevent reoccurrence of the situation that resulted in excess PM emissions; or
7) If no deviations occur during a quarterly reporting period, the report shall contain a negative declaration.

ii. The owner or operator shall submit a written report of excess emissions and the nature and cause of the excess emissions if known. See Specific Condition S3.a.ii.

d. **Opacity**

i. The owner or operator shall identify all periods of exceeding an opacity standard during a quarterly reporting period. The report shall include the following:

1) Any deviation from the requirement to perform daily (or monthly, if required) visible emission surveys or Method 9 tests and documented reason;
2) Any deviation from the requirement to record the results of each VE survey and Method 9 test performed and documented reason;
3) The number, date, and time of each VE Survey where visible emissions were observed and the results of the Method 9 test performed;
4) Identification of all periods of exceeding an opacity standard;
5) Description of any corrective action taken for each exceedance of the opacity standard; or
6) If no deviations occur during a quarterly reporting period, the report shall contain a negative declaration.

ii. The owner or operator shall comply with the reporting requirements for the Acid Rain Permit No.176-97-AR (R4), specified in 40 CFR 75, Subpart G. Notifications, monitoring Plans, Initial Certification and Recertification Applications, Quarterly Reports, Opacity Reports, Petitions to the Administrator, and Retired Unit Petitions shall be submitted as specified in

Subpart G - reporting requirements. (See Attachment E) (Regulation 6.47, section 3.4 and 3.5 referencing 40 CFR Parts 75 and 76)

iii. For coal silos (E2):

The owner or operator shall identify all periods of exceeding an opacity standard during a quarterly reporting period. The report shall include the following:

1) Emission Unit ID number, Stack ID number, and/or Emission point ID number;
2) The beginning and ending date of the reporting period;
3) The date, time and results of each exceedance of the opacity standard;
4) Description of any corrective action taken for each exceedance.

e. **TAC**

i. The owner or operator shall identify all periods of exceeding a TAC emission standard during a quarterly reporting period. The report shall include the following:

1) Emission Unit ID number and emission point ID number;
2) Identification of all periods during which a deviation occurred;
3) A description, including the magnitude, of the deviation;
4) If known, the cause of the deviation;
5) A description of all corrective actions taken to abate the deviation; and
6) If no deviations occur during a quarterly reporting period, the report shall contain a negative declaration.

ii. See Plantwide Requirements S2.b.

f. **HAP** (40 CFR 63, Subpart UUUUU)

i. The owner or operator shall comply with 40 CFR 63, Subpart UUUUU (See Attachment A) no later than April 16, 2016.

ii. Report normal pH range of reactant material in the FGD and normal range of any other parameters verified as having a direct effect on Hg emission within 30 days of establishing the normal range.

iii. The owner or operator shall identify all periods of the activated carbon injection rate are less than the minimum injection rate, or the pH of the reactant material in the FGD are out of normal range, or anytime other verified parameters are outside of their normal range, and any corrective action taken for each exceedance.

g. **BART** (40 CFR 52, Subpart S)

The owner or operator shall report any periods of time where the process was operating and both PJFF baghouse and ESP were not operating.

S4. **Testing** (Regulation 2.16, section 4.1.9.1)

a. **Control efficiency determination**

The owner or operator shall conduct performance test for the new EGU control device C26 and C27, according to the testing requirements in Attachment B, C and G.[24,25] (Regulation 2.16, section 4.1.9.1)

U1 Comments

1. Boiler (E1) has TAC emission standards since its EA Demonstration was based on controlled PTE. If the controlled PTE for the TAC is less than de minimis level, use De Minimis as limit. If the controlled PTE for the TAC is greater than de minimis level, modeling results were used to calculate risk value to compare to the EA Goals. In this case, controlled PTE is used as limit. TAC emissions for the coal silos (E2) are de minimis according to Regulation 5.21, section 2.1. The TAC emission limits determined by de minimis values shall be updated each time when the District revises the BAC/de minimis values for these TACs. The current de minimis values per TAC list revised on 10/14/2013 are as the following:

TAC Name	CAS #	De minimis values (lb/hr)	De minimis values (lb/yr)
Benzene	71-43-2	0.243	216
Bromoform	75-25-2	0.4914	437
Chloroform	67-66-3	0.02322	20.6
Methylene chloride	75-09-2	54	48,000
Tetrachloroethylene (Perc)	127-18-4	2.079	1,848
Toluene	108-88-3	2700	2,400,000
Xylene	1330-20-7	54	48,000
Hydrochloric acid	7647-01-0	10.8	9,600

[24] Per an EPA rule change ("Restructuring of the Stationary Source Audit Program." Federal Register 75:176 (September 13, 2010) pp 55636-55657), if an audit sample is required by the test method, sources became responsible for obtaining the audit samples directly from accredited audit sample suppliers, not the regulatory agencies.

[25] This unit was modified under construction permit 34595-12-C. According to permit 34595-12-C, the source is required to conduct stack tests to obtain actual emission factors and control efficiencies.

Emission Unit U2: Electric Utility Steam Generating Unit (EGU) – Unit 2

U2 Applicable Regulations:

FEDERALLY ENFORCEABLE REGULATIONS		
Regulation	**Title**	**Applicable Sections**
6.02	Emission Monitoring for Existing Sources	1, 2, 5, 6, 7, 8, 9, 10, 11, 12, 13, 14, 15, 16, 17, 18
6.07	Standards of Performance for Existing Indirect Heat Exchangers	1, 2, 3, 4
6.09	Standards of Performance for Existing Process Operations	1, 2, 3, 5
6.42	Reasonably Available Control Technology Requirements for Major Volatile Organic Compound- and Nitrogen Oxides-Emitting Facilities	1, 2, 3, 4, 5
6.47	Federal Acid Rain Program for Existing Sources Incorporated by Reference	1, 2, 3, 4, 5
40 CFR 64	Compliance Assurance Monitoring for Major Stationary Sources	64.1 through 64.10
40 CFR 72	Permits Regulation	Subparts A, B, C, D, E, F, G, H, I
40 CFR 73	Sulfur Dioxide Allowance System	Subparts A, B, C, D, E, F, G
40 CFR 75	Continuous Emission Monitoring	Subparts A, B, C, D, E, F, G
40 CFR 76	Acid Rain Nitrogen Oxides Emission Reduction Program	76.1, 76.2, 76.3, 76.4, 76.5, 76.7, 76.8, 76.9, 76.11, 76.13, 76.14, 76.15, Appendix A, Appendix B
40 CFR 77	Excess Emissions	77.1, 77.2, 77.3, 77.4, 77.5, 77.6
40 CFR 78	Appeals Procedures for Acid Rain Program	78.1, 78.2, 78.3, 78.4, 78.5, 78.6, 78.8, 78.9, 78.10, 78.11, 78.13, 78.14, 78.15, 78.16, 78.17, 78.18, 78.19, 78.20
40 CFR 63, Subpart UUUUU	National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units (EGU MACT)	63.9980 through 63.10042

DISTRICT ONLY ENFORCEABLE REGULATIONS		
Regulation	**Title**	**Applicable Sections**
5.00	Definitions	1, 2
5.01	General Provisions	1 through 2
5.02	Adoption of National Emission Standards for Hazardous Air Pollutants	1, 3.95 and 4
5.14	Hazardous Air Pollutants and Source Categories	1, 2
5.20	Methodology for Determining Benchmark Ambient Concentration of a Toxic Air Contaminant	1 through 6
5.21	Environmental Acceptability for Toxic Air Contaminants	1 through 5
5.22	Procedures for Determining the Maximum Ambient Concentration of a Toxic Air Contaminant	1 through 5
5.23	Categories of Toxic Air Contaminants	1 through 6

U2 Equipment:

Emission Point	Description	Applicable Regulation	Control ID	Stack ID
E3	One (1) tangentially fired boiler, rated capacity 3,085 MMBtu/hr, make Combustion Engineering, using pulverized coal as a primary fuel and natural gas as secondary fuel.	5.00, 5.01, 5.02, 5.14, 5.20, 5.21, 5.22, 5.23, 6.02, 6.07, 6.42, 6.47, 40 CFR 64, 40 CFR 72-73, 40 CFR 75-78, 40 CFR 63, UUUUU	C4, C5[a]	S2[a]
			C4, C27[b], C28[b]	S33[b]
E4	Four (4) coal silos, make American Air Filter, controlled by a centrifugal dust collector and equipped with four (4) coal mills, make Combustion Engineering Raymond Bowl Mills.	5.00, 5.01, 5.20, 5.21, 5.22, 5.23, 6.09	C6	S6
Note a: The existing FGD (C5, S2) will shut down before April 16, 2016, the compliance date when this unit has to comply with 40 CFR 63, Subpart UUUUU. Note b: The new FGD and HAP PM control (C27, C28, and S33) will replace C5 and S2. These new control devices need to be in full operation no later than April 16, 2016, the compliance date when this unit has to comply with 40 CFR 63, Subpart UUUUU.[26]				

[26] On June 3, 2015, LG&E submitted a notification for initial startup of PJFF (C28) and FGD (C27) for U2. These control devices went into service on May 27, 2015.

U2 Control Devices:

Before compliance with 40 CFR 63, Subpart UUUUU, Unit 2 uses the following control devices:

ID	Description	Performance Indicator	Stack ID
C4	One (1) custom-built electrostatic precipitator (ESP) for PM control, make Western Precipitator Division	PM emission data from PM CEMS (if PM CEMS is not used to demonstrate compliance)	S2
C5	One (1) Flue Gas Desulfurization (FGD) unit for SO_2 control using limestone scrubbing liquor, make Combustion Engineering	N/A[27]	
C6	One (1) centrifugal dust collector, make American Air Filter	N/A[28]	S6

After compliance with 40 CFR 63, Subpart UUUUU, Unit 2 uses the following control devices:

ID	Description	Performance Indicator	Stack ID
C4	One (1) custom-built electrostatic precipitator (ESP) for PM control, make Western Precipitator Division	N/A[27]	S33
C27	One (1) combined Flue Gas Desulfurization (FGD) unit for SO2 control using limestone scrubbing liquor, make Babcock Power Environmental	N/A[27]	
C28	One (1) HAP particulate matter control system, consists of: one (1) powdered activated carbon (PAC) injection system; one (1) dry sorbent injection system; liquid additive system(s); and one (1) pulse-jet fabric filter (PJFF) baghouse used for collecting PM from the boiler and PAC and dry sorbent injection system. PJFF make Clyde Bergemann Power Group, model Structural Pulse Jet	PM Control: PM emission data from PM CEMS (if PM CEMS is not used to demonstrate compliance) Hg control: (1) Minimum PAC injection rate;[29] (2) pH of reactant in FGD, 4.8-6.4; (3) Hg emission data from Sorbent Traps	

[27] This unit is equipped with CEMS for NOx, SO2, and PM. According to the District's letter dated November 1, 2005, parametric monitoring of the ESP, FGD, and PJFF for this unit is removed as such monitoring would no longer be required for demonstration of compliance. On July 22, 2016, LG&E reported the normal pressure drop range for U2 PJFF, 2 – 6 inches of water, established during 90 consecutive operating days.

[28] For the coal silos (E4), the owner or operator has shown, by worst-case calculations without allowance for a control device, that the hourly uncontrolled PM emission standard cannot be exceeded; therefore, no additional monitoring, recordkeeping, or reporting is required to demonstrate compliance with the applicable PM standards specified in Regulation 6.09 is required for this emission point.

[29] In a letter dated October 4, 2016, LG&E demonstrated that in certain circumstance EGUs at this plant can meet the MACT mercury standard at zero PAC injection rate. Therefore the source is allowed to use flexible mercury control measures, including PAC injection or liquid additive system, to achieve compliance with MACT mercury standard.

ID	Description	Performance Indicator	Stack ID
C6	One (1) centrifugal dust collector, make American Air Filter	N/A[28]	S6

U2 Specific Conditions

S1. **Standards**[30] (Regulation 2.16, section 4.1.1)

a. **NO_x**

i. The owner or operator shall not allow the average NO_x emissions to exceed the alternate contemporaneous emission limitation of 0.40 lb/MMBtu of heat input on an annual average basis, as specified in Acid Rain Permit No.176-97-AR (R4) which is attached and considered part of the Title V Operating Permit. (Regulation 6.47, section 3.5 referencing 40 CFR Part 76)

ii. The owner or operator shall not exceed the NOx RACT emissions standard of 0.47 lb/MMBtu of heat input based on a rolling 30-day average. (See NOx RACT, Attachment D) (Regulation 6.42, section 4.3)

iii. The owner or operator shall install, maintain, calibrate and operate a continuous emission monitoring system (CEMS) for the measurement or calculation of nitrogen oxides in the flue gas. (Regulation 6.02, section 6.1.3) (NO_x RACT Plan) (Regulation 6.47, section 3.4 referencing 40 CFR 75.10(a)(2))

b. **SO_2**

i. The owner or operator shall not exceed 1.2 lb/MMBtu per hour heat input based on a three hour rolling average. (Regulation 6.07, section 4.1)

ii. The owner or operator shall comply with the SO_2 emission allowances specified in Acid Rain Permit No.176-97-AR (R4). (See Acid Rain Permit Attachment) (Regulation 6.47, section 3.2 referencing 40 CFR Part 73)

iii. The owner or operator shall operate and maintain the FGD, as recommended by the manufacturer, at all times the respective boiler is in operation, including periods of startup, shutdown, and malfunction, in a manner consistent with good air pollution control practice to meet the standards.[31] (Regulation 2.16, section 4.1.1)

iv. The owner or operator shall install, maintain, calibrate and operate a continuous emission monitoring system (CEMS) for the measurement of

[30] The emission standards, monitoring, record keeping, and reporting requirements only apply to the boiler E3 (not the coal silos E4) if not indicated.

[31] The SO2 emissions cannot meet the standards uncontrolled. The owner or operator is required to operate the control devices to meet the applicable limits for SO2.

sulfur dioxide in the flue gas. (Regulation 6.02, section 6.1.2) (Regulation 6.47, section 3.4 referencing 40 CFR 75.10(a)(1))

c. **PM**

i. The owner or operator shall not exceed an allowable particulate emission rate of 0.11 lbs/MMBtu heat input based on a three hour rolling average. (Regulation 6.07, section 3.1)

ii. The owner or operator shall operate and maintain the PM control devices, as recommended by the manufacturer, at all times the respective boiler is in operation, including periods of startup, shutdown, and malfunction, in a manner consistent with good air pollution control practice to meet the standards. Following commissioning of the PJFF baghouses, the owner or operator may elect to operate, turn down, or turn off the ESP to ensure the efficient operation of the PJFF baghouse.[32] (Regulation 2.16, section 4.1.1)

iii. The company shall follow one of the two options below to demonstrate compliance with PM standards:

Compliance Options	PM	Opacity	Control Device Performance indication
Option 1	Certified PM CEMS	VE/Method 9, or Certified COMS	N/A
Option 2	Annual testing	Certified COMS	PM CEMS

iv. For the coal silos (E4), the owner or operator shall not exceed an allowable particulate emission rate of 82.95 lbs/hr from four coal silos combined based on actual operating hours in a calendar day.[33] (Regulation 6.09, section 3.2)

d. **Opacity**

i. The owner or operator shall not cause the emission into the open air of particulate matter from any indirect heat exchanger which is greater than 20% opacity, except emissions into the open air of particulate matter from any indirect heat exchanger during building a new fire, cleaning the fire box, or blowing soot for a period or periods aggregating not more than ten

[32] The PM emissions cannot meet the standards uncontrolled. The owner or operator is required to operate the control devices to meet the applicable limits for PM.

[33] For the coal silos (E4), the owner or operator has shown, by worst-case calculations without allowance for a control device, that the hourly uncontrolled PM emission standard cannot be exceeded; therefore, no additional monitoring, recordkeeping, or reporting is required to demonstrate compliance with the applicable PM standards specified in Regulation 6.09 is required for this emission point.

minutes in any 60 minutes which are less than 40% opacity. (Regulation 6.07, section 3.2 and 3.3)

ii. The company shall follow one of the two options in the table under Specific Condition S1.c.iii to demonstrate compliance with opacity standards.

iii. For the coal silos (E4), the owner or operator shall not allow visible emissions to equal or exceed 20% opacity. (Regulation 6.09, section 3.1)

e. **TAC**

i. The owner or operator shall not allow TAC emissions from boiler E3 to exceed the TAC emission standards determined based upon the EA Demonstration provided to the District.[34] (Regulation 5.21, section 4.2 and section 4.3) (See Comment 1)

TAC Name	CAS #	TAC Limits Determination (lbs/yr)	Basis of Limits
Naphthalene	91-20-3	16.6	Controlled PTE
Formaldehyde	50-00-0	70.3	Controlled PTE
Hydrogen fluoride	7664-39-3	13,385	Controlled PTE
Arsenic compounds	7440-38-2	266	Controlled PTE
Cadmium compounds	7440-43-9	42.1	Controlled PTE
Chromium VI	7440-47-3	94.5	Controlled PTE
Chromium III	16065-83-1	216	Controlled PTE
Cobalt compounds	7440-48-4	56.2	Controlled PTE
Lead compounds	7439-92-1	332	Controlled PTE
Manganese compounds	7439-96-5	424	Controlled PTE
Nickel compounds	7440-02-0	307	Controlled PTE
Sulfuric acid	7664-93-9	118,679	Controlled PTE
Benzene	71-43-2	De minimis values (See Comment 1)	De Minimis
Bromoform	75-25-2		De Minimis
Chloroform	67-66-3		De Minimis
Methylene chloride	75-09-2		De Minimis
Tetrachloroethylene (Perc)	127-18-4		De Minimis
Toluene	108-88-3		De Minimis
Xylene	1330-20-7		De Minimis
Hydrochloric acid	7647-01-0		De Minimis

ii. See Plantwide Requirements S1.b.

[34] This table for TAC emission standards has been revised to exclude Category 3 and 4 TACs for existing sources and use "de minimis values", instead of actual numbers for current de minimis levels, as emission standards.

f. **HAP** (40 CFR 63, Subpart UUUUU)

The owner or operator shall comply with 40 CFR 63, Subpart UUUUU (See Attachment A) no later than April 16, 2016.[35]

g. **BART** (40 CFR 52, Subpart S)

The owner or operator shall continue to utilize PJFF baghouse and/or existing ESP to control PM emissions for this unit.[36] (40 CFR 52.920(e) refer to Kentucky Regional Haze SIP)

S2. **Monitoring and Record Keeping** (Regulation 2.16, sections 4.1.9.1 and 4.1.9.2)

The owner or operator shall maintain the following records for a minimum of 5 years and make the records readily available to the District upon request.

a. **NO_x**

i. The owner or operator shall demonstrate compliance with NO_x RACT Plan limits by continuous emissions monitors (CEMs) as specified in the NO_x RACT Plan. (See NO_x RACT Attachment) (Regulation 6.42, section 4.3)

ii. The owner or operator shall keep a record identifying all deviations from the requirements of the NO_x RACT Plan.

iii. The owner or operator shall comply with the NO_x compliance plan requirements specified in the attached Acid Rain Permit, No.176-97-AR (R4). These record keeping requirements shall be determined in accordance with the Title IV Phase II Acid Rain Permit and are specified in 40 CFR Part 75 Subpart F. (See Appendix A to NOx RACT Plan) (Regulation 6.47, section 3.4 and 3.5 referencing 40 CFR Parts 75 and 76)

iv. The owner or operator shall record on an hourly basis all NO_x emission data specified in 40 CFR Part 75, section 75.57(d). For each NO_x emission rate (in lb/mmBtu) measured by a NO_x-diluent monitoring system, or, if applicable, for each NO_x concentration (in ppm) measured by a NO_x concentration monitoring system used to calculate NO_x mass emissions under 40 CFR 75.71(a)(2), record the following data as measured and

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[35] According to 40 CFR 63.9984(b), the compliance date for an existing EGU is April 16, 2015. LG&E requested a year extension and the District has approved the request for the extension per (40 CFR 63.6(i)(4)(i)). Therefore the compliance date for the EGUs under this construction is April 16, 2016.

[36] On March 30, 2012, EPA finalized a limited approval and a limited disapproval of the Kentucky state implementation plan submitted on June 25, 2008 and May 28, 2010. According to 40 CFR 52.920(e), the owner or operator shall meet BART requirements summarized in Table 7.5.3-2 of the Commonwealth’s May 28, 2010 submittal.

reported from the certified primary monitor, certified back-up monitor, or other approved method of emissions determination:

1) Component-system identification code, as provided in 40 CFR 75.53 (including identification code for the moisture monitoring system, if applicable); (40 CFR 75.57(d)(1))

2) Date and hour; (40 CFR 75.57(d)(2))

3) Hourly average NO_x concentration (ppm, rounded to the nearest tenth) and hourly average NO_x concentration (ppm, rounded to the nearest tenth) adjusted for bias if bias adjustment factor required, as provided in 40 CFR 75.24(d); (40 CFR 75.57(d)(3))

4) Hourly average diluent gas concentration (for NO_x -diluent monitoring systems, only, in units of percent O_2 or percent CO_2, rounded to the nearest tenth); (40 CFR 75.57(d)(4))

5) If applicable, the hourly average moisture content of the stack gas (percent H_2O, rounded to the nearest tenth). If the continuous moisture monitoring system consists of wet- and dry-basis oxygen analyzers, also record both the hourly wet- and dry-basis oxygen readings (in percent O2, rounded to the nearest tenth); (40 CFR 75.57(d)(5))

6) Hourly average NO_x emission rate (for NO_x -diluent monitoring systems only, in units of lb/mmBtu, rounded to the nearest thousandth); (40 CFR 75.57(d)(6))

7) Hourly average NO_x emission rate (for NO_x -diluent monitoring systems only, in units of lb/mmBtu, rounded to the nearest thousandth), adjusted for bias if bias adjustment factor is required, as provided in 40 CFR 75.24(d). The requirement to report hourly NO_x emission rates to the nearest thousandth shall not affect NO_x compliance determinations under part 76 of this chapter; compliance with each applicable emission limit under part 76 shall be determined to the nearest hundredth pound per million Btu; (40 CFR 75.57(d)(7))

8) Percent monitoring system data availability (recorded to the nearest tenth of a percent), for the NO_x -diluent or NO_x concentration monitoring system, and, if applicable, for the moisture monitoring system, calculated pursuant to 40 CFR 75.32; (40 CFR 75.57(d)(8))

9) Method of determination for hourly average NO_x emission rate or NO_x concentration and (if applicable) for the hourly average

moisture percentage, using Codes 1–55 in Table 4a of 40 CFR 75.57; and (40 CFR 75.57(d)(9))

10) Identification codes for emissions formulas used to derive hourly average NO_x emission rate and total NO_x mass emissions, as provided in 40 CFR 75.53, and (if applicable) the F-factor used to convert NO_x concentrations into emission rates. (40 CFR 75.57(d)(10))

v. A CEMS for measuring either oxygen (O_2) or carbon dioxide (CO_2) in the flue gases shall be installed, calibrated, maintained, and operated by the owner or operator. (Regulation 6.02, section 6.1.3) (NO_x RACT Plan)

vi. The owner or operator shall monitor the NO_x emissions, the NO_x allowances, as specified in the Clean Air Interstate Rule or the applicable NO_x cap and trade program(s) in effect.

vii. The owner or operator shall comply with the following in order to demonstrate compliance with the emission standard as required by 40 CFR 52: For performance evaluations under 40 CFR 60.13(c) and calibration checks under 40 CFR 60.13(d), the following procedures shall be used:

1) Methods 6, 7, and 3B of appendix A of this part, as applicable, shall be used for the performance evaluations of SO_2 and NO_X continuous monitoring systems. Acceptable alternative methods for Methods 6, 7, and 3B of appendix A of this part are given in 40 CFR 60.46(d).

2) Sulfur dioxide or nitric oxide, as applicable, shall be used for preparing calibration gas mixtures under Performance Specification 2 of appendix B to this part.

3) For affected facilities burning fossil fuel(s), the span value for a continuous monitoring system measuring the opacity of emissions shall be 80, 90, or 100 percent. For a continuous monitoring system measuring sulfur oxides or NO_X the span value shall be determined using one of the following procedures:

(a) Except as provided under paragraph 40 CFR 60.45(c)(3)(ii), SO_2 and NO_X span values shall be determined as follows:

Fossil fuel	In parts per million	
	Span value for SO_2	Span value for NO_X
Gas	Not Applicable	500.
Liquid	1,000	500.
Solid	1,500	1,000.

(b) As an alternative to meeting the requirements of paragraph 40 CFR 60.45(c)(3)(i), the owner or operator of an affected facility may elect to use the SO_2 and NO_X span values determined according to sections 2.1.1 and 2.1.2 in appendix A to part 75 of this chapter.

viii. The owner or operator shall comply with the following in order to demonstrate compliance with the emission standard as required by 40 CFR 52: The conversion procedures in 40 CFR 60.45(e) and (f) shall be used to convert the continuous monitoring data into units of the applicable standards.

1) For any CEMS installed under paragraph (a) of this section, the following conversion procedures shall be used to convert the continuous monitoring data into units of the applicable standards (ng/J, lb/MMBtu):

(a) When a CEMS for measuring O_2 is selected, the measurement of the pollutant concentration and O_2 concentration shall each be on a consistent basis (wet or dry). Alternative procedures approved by the Administrator shall be used when measurements are on a wet basis. When measurements are on a dry basis, the following conversion procedure shall be used:

$$E = CF\left(\frac{20.9}{(20.9 - \%O_2)}\right)$$

Where E, C, F, and $\%O_2$ are determined under paragraph (f) of this section.

(b) When a CEMS for measuring CO_2 is selected, the measurement of the pollutant concentration and CO_2 concentration shall each be on a consistent basis (wet or dry) and the following conversion procedure shall be used:

$$E = CF_c\left(\frac{100}{\%CO_2}\right)$$

Where E, C, F_c and $\%CO_2$ are determined under paragraph (f) of this section.

2) The values used in the equations under paragraphs (e)(1) and (2) of this section are derived as follows:

(a) E = pollutant emissions, ng/J (lb/MMBtu).

(b) C = pollutant concentration, ng/dscm (lb/dscf), determined by multiplying the average concentration (ppm) for each one-hour period by 4.15×10^{4} M ng/dscm per ppm (2.59×10^{-9}M lb/dscf per ppm) where M = pollutant molecular weight, g/g-mole (lb/lb-mole). M = 64.07 for SO_2 and 46.01 for NO_X.

(c) $\%O_2$, $\%CO_2$= O_2 or CO_2 volume (expressed as percent), determined with equipment specified under paragraph (a) of this section.

(d) F, F_c= a factor representing a ratio of the volume of dry flue gases generated to the calorific value of the fuel combusted (F), and a factor representing a ratio of the volume of CO_2 generated to the calorific value of the fuel combusted (F_c), respectively. Values of F and F_c are given as follows:

(i) For anthracite coal as classified according to ASTM D388 (incorporated by reference, see 40 CFR 60.17), F = $2,723 \times 10^{-17}$ dscm/J (10,140 dscf/MMBtu) and F_c= 0.532×10^{-17} scm CO_2/J (1,980 scf CO_2/MMBtu).

(ii) For subbituminous and bituminous coal as classified according to ASTM D388 (incorporated by reference, see 40 CFR 60.17), F = 2.637×10^{-7} dscm/J (9,820 dscf/MMBtu) and F_c= 0.486×10^{-7} scm CO_2/J (1,810 scf CO_2/MMBtu).

(iii) For liquid fossil fuels including crude, residual, and distillate oils, F = 2.476×10^{-7} dscm/J (9,220 dscf/MMBtu) and F_c= 0.384×10^{-7} scm CO_2/J (1,430 scf CO_2/MMBtu).

(iv) For gaseous fossil fuels, F = 2.347×10^{-7} dscm/J (8,740 dscf/MMBtu). For natural gas, propane, and butane fuels, F_c= 0.279×10^{-7} scm CO_2/J (1,040 scf CO_2/MMBtu) for natural gas, 0.322×10^{-7} scm CO_2/J (1,200 scf CO_2/MMBtu) for propane, and 0.338×10^{-7} scm CO_2/J (1,260 scf CO_2/MMBtu) for butane.

(v) For bark F = 2.589×10^{-7} dscm/J (9,640 dscf/MMBtu) and F_c= 0.500×10^{-7} scm CO_2/J (1,840 scf CO_2/MMBtu). For wood residue other than bark F = 2.492×10^{-7} dscm/J (9,280 dscf/MMBtu) and F_c= 0.494×10^{-7} scm CO_2/J (1,860 scf CO_2/MMBtu).

(vi) For lignite coal as classified according to ASTM D388 (incorporated by reference, see 40 CFR 60.17),

$F = 2.659 \times 10^{-7}$ dscm/J (9,900 dscf/MMBtu) and $F_c = 0.516 \times 10^{-7}$ scm CO_2/J (1,920 scf CO_2/MMBtu).

(e) The owner or operator may use the following equation to determine an F factor (dscm/J or dscf/MMBtu) on a dry basis (if it is desired to calculate F on a wet basis, consult the Administrator) or Fc factor (scm CO_2/J, or scf CO_2/MMBtu) on either basis in lieu of the F or F_c factors specified in paragraph (f)(4) of this section:

$$F = 10^{-6} \frac{[227.2\ (\%H) + 95.5\ (\%C) + 35.6\ (\%S) + 8.7\ (\%N) - 28.7\ (\%O)]}{GCV}$$

$$F_c = \frac{2.0 \times 10^{-5}\ (\%C)}{GCV\ (SI\ units)}$$

$$F = 10^{-6} \frac{[3.64\ (\%H) + 1.53\ (\%C) + 0.57\ (\%S) + 0.14\ (\%N) - 0.46\ (\%O)]}{GCV\ (English\ units)}$$

$$F_c = \frac{20.0\ (\%C)}{GCV\ (SI\ units)}$$

$$F_c = \frac{321 \times 10^{3}\ (\%C)}{GCV\ (English\ units)}$$

(i) %H, %C, %S, %N, and %O are content by weight of hydrogen, carbon, sulfur, nitrogen, and O_2(expressed as percent), respectively, as determined on the same basis as GCV by ultimate analysis of the fuel fired, using ASTM D3178 or D3176 (solid fuels), or computed from results using ASTM D1137, D1945, or D1946 (gaseous fuels) as applicable. (These five methods are incorporated by reference, see 40 CFR 60.17.)

(ii) GVC is the gross calorific value (kJ/kg, Btu/lb) of the fuel combusted determined by the ASTM test methods D2015 or D5865 for solid fuels and D1826 for gaseous fuels as applicable. (These three methods are incorporated by reference, see 40 CFR 60.17.)

(iii) For affected facilities which fire both fossil fuels and nonfossil fuels, the F or Fc value shall be subject to the Administrator's approval.

(f) For affected facilities firing combinations of fossil fuels or fossil fuels and wood residue, the F or Fc factors determined by paragraphs (f)(4) or (f)(5) of this section shall be prorated in accordance with the applicable formula as follows:

$$F = \sum_{i=1}^{n} X_i F_i \quad \text{or} \quad F_c = \sum_{i=1}^{n} X_i \left(F_c\right)_i$$

Where:
X_i= Fraction of total heat input derived from each type of fuel (e.g. natural gas, bituminous coal, wood residue, etc.);
F_i or $(F_c)_i$= Applicable F or F_c factor for each fuel type determined in accordance with paragraphs (f)(4) and (f)(5) of this section; and
n = Number of fuels being burned in combination.

b. **SO_2**

i. The owner or operator shall maintain hourly records of SO_2 emissions as specified in Regulation 6.02, section 6.1.2.

ii. The owner or operator shall record on an hourly basis all SO_2 emission data specified in 40 CFR 75.57(c):

1) For SO_2 concentration during unit operation, as measured and reported from each certified primary monitor, certified back-up monitor, or other approved method of emissions determination: (40 CFR 75.57(c)(1))

(a) Component-system identification code, as provided in 40 CFR 75.53; (40 CFR 75.57(c)(1)(i))

(b) Date and hour; (40 CFR 75.57(c)(1)(ii))

(c) Hourly average SO_2 concentration (ppm, rounded to the nearest tenth); (40 CFR 75.57(c)(1)(iii))

(d) Hourly average SO_2 concentration (ppm, rounded to the nearest tenth), adjusted for bias if bias adjustment factor is required, as provided in 40 CFR 75.24(d); (40 CFR 75.57(c)(1)(iv))

(e) Percent monitor data availability (recorded to the nearest tenth of a percent), calculated pursuant to 40 CFR 75.32; and (40 CFR 75.57(c)(1)(v))

(f) Method of determination for hourly average SO_2 concentration using Codes 1–55 in Table 4a of 40 CFR 75.57. (40 CFR 75.57(c)(1)(vi))

2) For flow rate during unit operation, as measured and reported from each certified primary monitor, certified back-up monitor, or other approved method of emissions determination: (40 CFR 75.57(c)(2))

(a) Component-system identification code, as provided in 40 CFR 75.53; (40 CFR 75.57(c)(2)(i))

(b) Date and hour; (40 CFR 75.57(c)(2)(ii))

(c) Hourly average volumetric flow rate (in scfh, rounded to the nearest thousand); (40 CFR 75.57(c)(2)(iii))

(d) Hourly average volumetric flow rate (in scfh, rounded to the nearest thousand), adjusted for bias if bias adjustment factor required, as provided in 40 CFR 75.24(d); (40 CFR 75.57(c)(2)(iv))

(e) Percent monitor data availability (recorded to the nearest tenth of a percent) for the flow monitor, calculated pursuant to 40 CFR 75.32; and (40 CFR 75.57(c)(2)(v))

(f) Method of determination for hourly average flow rate using Codes 1–55 in Table 4a of 40 CFR 75.57. (40 CFR 75.57(c)(2)(vi))

3) For SO_2 mass emission rate during unit operation, as measured and reported from the certified primary monitoring system(s), certified redundant or non-redundant back-up monitoring system(s), or other approved method(s) of emissions determination: (40 CFR 75.57(c)(4))

(a) Date and hour; (40 CFR 75.57(c)(4)(i))

(b) Hourly SO_2 mass emission rate (lb/hr, rounded to the nearest tenth); (40 CFR 75.57(c)(4)(ii))

(c) Hourly SO_2 mass emission rate (lb/hr, rounded to the nearest tenth), adjusted for bias if bias adjustment factor required, as provided in 40 CFR 75.24(d); and (40 CFR 75.57(c)(4)(iii))

(d) Identification code for emissions formula used to derive hourly SO2 mass emission rate from SO2 concentration and flow and (if applicable) moisture data in paragraphs (c)(1), (c)(2), and (c)(3) of 40 CFR 75.57, as provided in 40 CFR 75.53. (40 CFR 75.57(c)(4)(iv))

iii. The owner or operator shall comply with the following in order to demonstrate compliance with the emission standard as required by 40 CFR 52: For performance evaluations under 40 CFR 60.13(c) and calibration checks under 40 CFR 60.13(d), the following procedures shall be used:

1) Methods 6, 7, and 3B of appendix A of this part, as applicable, shall be used for the performance evaluations of SO_2 and NO_X continuous monitoring systems. Acceptable alternative methods for Methods 6, 7, and 3B of appendix A of this part are given in 40 CFR 60.46(d).

2) Sulfur dioxide or nitric oxide, as applicable, shall be used for preparing calibration gas mixtures under Performance Specification 2 of appendix B to this part.

3) For affected facilities burning fossil fuel(s), the span value for a continuous monitoring system measuring the opacity of emissions shall be 80, 90, or 100 percent. For a continuous monitoring system measuring sulfur oxides or NO_X the span value shall be determined using one of the following procedures:

(a) Except as provided under paragraph 40 CFR 60.45(c)(3)(ii), SO_2 and NO_X span values shall be determined as follows:

Fossil fuel	In parts per million	
	Span value for SO_2	Span value for NO_X
Gas	Not Applicable	500.
Liquid	1,000	500.
Solid	1,500	1,000.

(b) As an alternative to meeting the requirements of paragraph 40 CFR 60.45(c)(3)(i), the owner or operator of an affected facility may elect to use the SO_2 and NO_X span values determined according to sections 2.1.1 and 2.1.2 in appendix A to part 75 of this chapter.

iv. The owner or operator shall comply with the following in order to demonstrate compliance with the emission standard as required by 40 CFR 52: The conversion procedures in 40 CFR 60.45(e) and (f) shall be used to convert the continuous monitoring data into units of the applicable standards.

1) For any CEMS installed under paragraph (a) of this section, the following conversion procedures shall be used to convert the

continuous monitoring data into units of the applicable standards (ng/J, lb/MMBtu):

(a) When a CEMS for measuring O_2 is selected, the measurement of the pollutant concentration and O_2 concentration shall each be on a consistent basis (wet or dry). Alternative procedures approved by the Administrator shall be used when measurements are on a wet basis. When measurements are on a dry basis, the following conversion procedure shall be used:

$$E = CF\left(\frac{20.9}{(20.9 - \%O_2)}\right)$$

Where E, C, F, and $\%O_2$ are determined under paragraph (f) of this section.

(b) When a CEMS for measuring CO_2 is selected, the measurement of the pollutant concentration and CO_2 concentration shall each be on a consistent basis (wet or dry) and the following conversion procedure shall be used:

$$E = CF_c\left(\frac{100}{\%CO_2}\right)$$

Where E, C, F_c and $\%CO_2$ are determined under paragraph (f) of this section.

2) The values used in the equations under paragraphs (e)(1) and (2) of this section are derived as follows:

(a) E = pollutant emissions, ng/J (lb/MMBtu).

(b) C = pollutant concentration, ng/dscm (lb/dscf), determined by multiplying the average concentration (ppm) for each one-hour period by 4.15×10^{4} M ng/dscm per ppm (2.59×10^{-9}M lb/dscf per ppm) where M = pollutant molecular weight, g/g-mole (lb/lb-mole). M = 64.07 for SO_2 and 46.01 for NO_X.

(c) $\%O_2$, $\%CO_2$= O_2 or CO_2 volume (expressed as percent), determined with equipment specified under paragraph (a) of this section.

(d) F, F_c= a factor representing a ratio of the volume of dry flue gases generated to the calorific value of the fuel combusted

(F), and a factor representing a ratio of the volume of CO_2 generated to the calorific value of the fuel combusted (F_c), respectively. Values of F and F_c are given as follows:

(i) For anthracite coal as classified according to ASTM D388 (incorporated by reference, see 40 CFR 60.17), F = 2,723 × 10 $^{-17}$ dscm/J (10,140 dscf/MMBtu) and F_c= 0.532 × 10 $^{-17}$ scm CO_2/J (1,980 scf CO_2/MMBtu).

(ii) For subbituminous and bituminous coal as classified according to ASTM D388 (incorporated by reference, see 40 CFR 60.17), F = 2.637 × 10 $^{-7}$ dscm/J (9,820 dscf/MMBtu) and F_c= 0.486 × 10 $^{-7}$ scm CO_2/J (1,810 scf CO_2/MMBtu).

(iii) For liquid fossil fuels including crude, residual, and distillate oils, F = 2.476 × 10 $^{-7}$ dscm/J (9,220 dscf/MMBtu) and F_c= 0.384 × 10 $^{-7}$ scm CO_2/J (1,430 scf CO_2/MMBtu).

(iv) For gaseous fossil fuels, F = 2.347 × 10 $^{-7}$ dscm/J (8,740 dscf/MMBtu). For natural gas, propane, and butane fuels, F_c= 0.279 × 10 $^{-7}$ scm CO_2/J (1,040 scf CO_2/MMBtu) for natural gas, 0.322 × 10 $^{-7}$ scm CO_2/J (1,200 scf CO_2/MMBtu) for propane, and 0.338 × 10 $^{-7}$ scm CO_2/J (1,260 scf CO_2/MMBtu) for butane.

(v) For bark F = 2.589 × 10 $^{-7}$ dscm/J (9,640 dscf/MMBtu) and F_c= 0.500 × 10 $^{-7}$ scm CO_2/J (1,840 scf CO_2/MMBtu). For wood residue other than bark F = 2.492 × 10 $^{-7}$ dscm/J (9,280 dscf/MMBtu) and F_c= 0.494 × 10 $^{-7}$ scm CO_2/J (1,860 scf CO_2/MMBtu).

(vi) For lignite coal as classified according to ASTM D388 (incorporated by reference, see 40 CFR 60.17), F = 2.659 × 10 $^{-7}$ dscm/J (9,900 dscf/MMBtu) and F_c= 0.516 × 10 $^{-7}$ scm CO_2/J (1,920 scf CO_2/MMBtu).

(e) The owner or operator may use the following equation to determine an F factor (dscm/J or dscf/MMBtu) on a dry basis (if it is desired to calculate F on a wet basis, consult the Administrator) or Fc factor (scm CO_2/J, or scf CO_2/MMBtu) on either basis in lieu of the F or F_c factors specified in paragraph (f)(4) of this section:

$$F = 10^{-6}\frac{[227.2\ (\%H) + 95.5\ (\%C) + 35.6\ (\%S) + 8.7\ (\%N) - 28.7\ (\%O)]}{GCV}$$

$$F_c = \frac{2.0\times10^{-5}(\%C)}{GCV\ (SI\ units)}$$

$$F = 10^{-6}\frac{[3.64\ (\%H) + 1.53\ (\%C) + 0.57\ (\%S) + 0.14\ (\%N) - 0.46\ (\%O)]}{GCV\ (English\ units)}$$

$$F_c = \frac{20.0\ (\%C)}{GCV\ (SI\ units)}$$

$$F_c = \frac{321\times10^{3}\ (\%C)}{GCV\ (English\ units)}$$

(i) %H, %C, %S, %N, and %O are content by weight of hydrogen, carbon, sulfur, nitrogen, and O_2(expressed as percent), respectively, as determined on the same basis as GCV by ultimate analysis of the fuel fired, using ASTM D3178 or D3176 (solid fuels), or computed from results using ASTM D1137, D1945, or D1946 (gaseous fuels) as applicable. (These five methods are incorporated by reference, see 40 CFR 60.17.)

(ii) GVC is the gross calorific value (kJ/kg, Btu/lb) of the fuel combusted determined by the ASTM test methods D2015 or D5865 for solid fuels and D1826 for gaseous fuels as applicable. (These three methods are incorporated by reference, see 40 CFR 60.17.)

(iii) For affected facilities which fire both fossil fuels and nonfossil fuels, the F or Fc value shall be subject to the Administrator's approval.

(f) For affected facilities firing combinations of fossil fuels or fossil fuels and wood residue, the F or Fc factors determined by paragraphs (f)(4) or (f)(5) of this section shall be prorated in accordance with the applicable formula as follows:

$$F = \sum_{i=1}^{n} X_i F_i \quad \text{or} \quad F_c = \sum_{i=1}^{n} X_i \left(F_c\right)_i$$

Where:
X_i= Fraction of total heat input derived from each type of fuel (e.g. natural gas, bituminous coal, wood residue, etc.);

F_i or $(F_c)_i$= Applicable F or F_c factor for each fuel type determined in accordance with paragraphs (f)(4) and (f)(5) of this section; and

n = Number of fuels being burned in combination.

c. **PM**

i. The company shall follow one of the two options below to demonstrate compliance with PM standards:

1) Option 1: the owner or operator shall install, maintain, calibrate, and operate a PM CEMS for each steam generating unit.[37,38] (Regulation 2.16, section 4.1.1) (40 CFR 64)

(a) The use of PM CEMS as the measurement technique must be appropriate for the stack conditions.

(b) The PM CEMS must be installed, operated and maintained in accordance with the manufacturer's recommendations.

(c) The PM CEMS must be certified in accordance with Performance Specification 11, Specifications and Test Procedures for Particulate Matter Continuous Emission Monitoring Systems at Stationary Sources, found in 40 CFR 60, Appendix B.

(d) A quality assurance/quality control program must be implemented in accordance with procedures in 40 CFR 60, Appendix F, Procedure 2 (Quality Assurance Requirements for Particulate Matter Continuous Emission Monitoring Systems at Stationary Sources).

(e) Compliance with the particulate matter emission limit will be based upon three-hour rolling average periods during source operation.

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[37] According to LG&E's request, PM CEMS have been installed, calibrated, maintained, and operated for Unit 1. LG&E requested permission to remove COMS for Unit 3 and 4 under provisions in 40 CFR 60.13(i)(1), "Alternative monitoring requirements when installation of a continuous monitoring system or monitoring device specified by this part would not provide accurate measurements due to liquid water or other interferences caused by substances in the effluent gases." LG&E's proposal for Unit 3 and 4 was accepted in a letter from EPA dated Feb. 28, 2007. The District accordingly approved LG&E's request for removing COMS for Unit 1 and 2 providing PM CEMS are appropriately installed for these units.

[38] The coal-fired boilers are subject to 40 CFR Part 64 - Compliance Assurance Monitoring (CAM) for Major Stationary Source since SO2, PM, and NOx emissions from each of the boilers may be greater than the major source threshold and control devices are required to achieve compliance with standards. On 5/21/2014, LG&E submitted a revised CAM Plan in which SO2 and NOx CEMS are used for compliance demonstration. PM CEMS is used to demonstrate compliance or provide an indication of continuous PM control.

(f) Quarterly excess emission reports must be submitted, and PM excess emissions shall be reported based upon three-hour rolling averages during source operation.

2) Option 2: the owner or operator shall conduct an annual EPA Reference Method 5 performance test following the testing requirements in Attachment B, Specific Condition b.ii.

ii. If certified PM CEMS (Option 1) is used to demonstrate compliance with PM standards, the owner or operator shall record on an hourly basis all PM emission data, in lb/MMBtu, from PM CEMS.[39] (40 CFR 64)

iii. If annual PM testing (Option 2) is used to demonstrate compliance with PM standards, the owner or operator shall use PM CEMS as a performance indicator of continuous normal operation of the PM control devices and do the following:[39] (40 CFR 64)

1) The owner or operator shall monitor and record all PM emission data from PM CEMS, which is used as the indicator of normal operation of the PM control devices.

2) The owner or operator shall maintain daily records of any periods of time where the process was operating and the PM control devices were not operating or a declaration that the PM control devices operated at all times that day when the process was operating.

3) If there is any time that the PM control devices are bypassed or not in operation when the process is operating, then the owner or operator shall keep a record of the following for each bypass event:

(a) Date;
(b) Start time and stop time;
(c) Identification of the control devices and process equipment;
(d) PM emissions during the bypass in lb/hr;
(e) Summary of the cause or reason for each bypass event;
(f) Corrective action taken to minimize the extent or duration of the bypass event; and
(g) Measures implemented to prevent reoccurrence of the situation that resulted in the bypass event.

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[39] The coal-fired boilers are subject to 40 CFR Part 64 - Compliance Assurance Monitoring (CAM) for Major Stationary Source since SO2, PM, and NOx emissions from each of the boilers may be greater than the major source threshold and control devices are required to achieve compliance with standards. On 5/21/2014, LG&E submitted a revised CAM Plan in which SO2 and NOx CEMS are used for compliance demonstration. PM CEMS is used to demonstrate compliance or provide an indication of continuous PM control.

d. **Opacity**

i. If certified COMS is used to demonstrate compliance with opacity standards, the owner or operator shall record on an hourly basis all opacity from COMS.[40]

ii. If VE/Method 9 is used to demonstrate compliance with opacity standards, in order for the owner or operator to use its VE observations to satisfy the opacity monitoring requirement, the following conditions must be met:[40] (EPA Letter, 2007)

1) On a weekly basis, the owner or operator shall attempt to perform VE observations in accordance with procedures in EPA Method 9.

2) On the weeks when it is possible to collect unit-specific VE data, at least one hour of Method 9 data shall be collected for each unit.

3) Records of the Method 9 readings shall be submitted with the quarterly excess emission reports for PM emissions.

iii. The owner or operator shall keep a record of every Method 9 test performed or the reason why it could not be performed that day.

iv. For coal silos (E4):

1) The owner or operator shall conduct a weekly one-minute visible emissions survey, during normal operation, of the PM Emission Points (stacks). For Emission Points without observed visible emissions during twelve consecutive operating weeks, the owner or operator may elect to conduct a monthly one-minute visible emission survey, during normal operation.

2) At Emission Points where visible emissions are observed, the owner or operator shall initiate corrective action within eight hours of the initial observation. If the visible emissions persist, the owner or operator shall perform or cause to be performed a Method 9 for stack emissions within 24 hours of the initial observation. If the opacity standard is exceeded, the owner or operator shall report the

[40] According to LG&E's request, PM CEMS have been installed, calibrated, maintained, and operated for Unit 1. LG&E requested permission to remove COMS for Unit 3 and 4 under provisions in 40 CFR 60.13(i)(1), "Alternative monitoring requirements when installation of a continuous monitoring system or monitoring device specified by this part would not provide accurate measurements due to liquid water or other interferences caused by substances in the effluent gases." LG&E's proposal for Unit 3 and 4 was accepted in a letter from EPA dated Feb. 28, 2007. The District accordingly approved LG&E's request for removing COMS for Unit 1 and 2 providing PM CEMS are appropriately installed for these units.

exceedance to the District, according to Regulation 1.07, and take all practicable steps to eliminate the exceedance.

3) The owner or operator shall maintain records, monthly, of the results of all visible emissions surveys and tests. Records of the results of any visible emissions survey shall include the date of the survey, the name of the person conducting the survey, whether or not visible emissions were observed, and what if any corrective action was performed. If an emission point is not being operated during a given month, then no visible emission survey needs to be performed and a negative declaration shall be entered in the record.

e. **TAC**

i. The owner or operator shall monthly calculate and record TAC emissions for this unit in order to demonstrate compliance with the TAC emission standards.

ii. See Plantwide Requirements S2.b.

f. **HAP** (40 CFR 63, Subpart UUUUU)

i. The owner or operator shall comply with 40 CFR 63, Subpart UUUUU (See Attachment A) no later than April 16, 2016.

ii. The owner or operator shall establish a site-specific minimum activated carbon injection rate for PAC injection system according to Attachment B, Specific Condition a.i. The owner or operator shall monitor and record the activated carbon injection rate during each operating day. [41]

iii. The owner or operator shall monitor and record all Hg emission data from the Hg sorbent traps, which is used as the indicator of normal operation of the Hg control measures.

iv. The owner or operator shall monitor and record the pH of the reactant material in the FGD and any other parameters verified as having a direct effect on Hg emissions during each operating day, which is (are) used as the indicator(s) of normal operation of Hg control measures. [42]

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[41] In a letter dated October 4, 2016, LG&E demonstrated that in certain circumstance EGUs at this plant can meet the MACT mercury standard at zero PAC injection rate. Therefore the source is allowed to use flexible mercury control measures, including PAC injection or liquid additive system, to achieve compliance with MACT mercury standard.

[42] LG&E has established normal pH range per monitoring records during consecutive 180 days. On 10/20/2016, LG&E reported that the normal pH range for this unit is 4.8 – 6.4.

v. The owner or operator shall maintain records of which Hg control devices/measure was being used during each operating day.

g. **BART** (40 CFR 52, Subpart S)

The owner or operator shall maintain daily records of any periods of time where the process was operating and both PJFF baghouse and ESP were not operating or a declaration that the PJFF baghouse and/or ESP operated at all times that day when the process was operating.

S3. **Reporting** (Regulation 2.16, section 4.1.9.3)

The owner or operator shall submit quarterly compliance reports that include the information in this section.

a. **NO_x**

i. The owner or operator shall identify all periods of exceeding a NO_x emission standard during a quarterly reporting period. The quarterly compliance report shall include the following:

1) Emission Unit ID number and emission point ID number;
2) Identification of all periods during which a deviation occurred;
3) A description, including the magnitude, of the deviation;
4) If known, the cause of the deviation;
5) A description of all corrective actions taken to abate the deviation; and
6) If no deviations occur during a quarterly reporting period, the report shall contain a negative declaration.

ii. The owner or operator shall submit a written report of excess emissions and the nature and cause of the excess emissions if known. The averaging period used for data reporting should correspond to the averaging period specified in the emission test method used to determine compliance with an emission standard for the pollutant/source category in question. All quarterly reports shall be postmarked by the 30th day following the end of each calendar quarter. The required report shall include: (Regulation 6.02, section 16.1)

1) For gaseous measurements, the summary shall consist of hourly averages in the units of the applicable standard. The hourly averages shall not appear in the written summary, but shall be made available electronically. (Regulation 6.02, section 16.3)

2) The data and time identifying each period during which the continuous monitoring system was inoperative, except for zero and span checks, and the nature of system repairs or adjustment shall be

reported. Proof of continuous monitoring system performance whenever system repairs or adjustments have been made is required. (Regulation 6.02, section 16.4)

3) When no excess emissions have occurred and the continuous monitoring systems have been inoperative, repaired, or adjusted, such information shall be included in the report. (Regulation 6.02, section 16.5)

4) Owners or operators of affected facilities shall maintain a file of all information reported in the quarterly summaries, and all other data collected either by the continuous monitoring system or as necessary to convert monitoring data to the units of the applicable standard for a minimum of two years from the date of collection of such data or submission of such summaries. (Regulation 6.02, section 16.6)

iii. The owner or operator shall comply with the reporting requirements for the Acid Rain Permit No.176-97-AR (R4), specified in 40 CFR 75, Subpart G. Notifications, Monitoring Plans, Initial Certification and Recertification Applications, Quarterly Reports, Opacity Reports, Petitions to the Administrator, and Retired Unit Petitions shall be submitted as specified in Subpart G - reporting requirements. (See Attachment E)

iv. The owner or operator shall comply with the reporting requirements for the Title IV NO_x Budget Emission Limitation, 0.40 lb/MMBtu, as specified in 40 CFR Part 76.

v. Excess emissions for affected facilities using a CEMS for measuring NO_X are defined as: (Regulation 2.16, section 4.1.9.3)

1) Any annual average period during which the average emissions (arithmetic average of all one-hour period during the 12 month period) of NOx as measured by a CEMS exceed the applicable standard.

2) Any 30 operating day period during which the average emissions (arithmetic average of all one-hour periods during the 30 operating days) of NO_X as measured by a CEMS exceed the applicable standard.

b. **SO_2**

i. The owner or operator shall identify all periods of exceeding a SO_2 emission standard during a quarterly reporting period. The report shall include the following:

1) Emission Unit ID number and emission point ID number;

2) Identification of all periods during which a deviation occurred;
3) A description, including the magnitude, of the deviation;
4) If known, the cause of the deviation;
5) A description of all corrective actions taken to abate the deviation; and
6) If no deviations occur during a quarterly reporting period, the report shall contain a negative declaration.

ii. The owner or operator shall submit a written report of excess emissions and the nature and cause of the excess emissions if known. See Specific Condition S3.a.ii.

iii. The owner or operator shall comply with the reporting requirements for the Acid Rain Permit No.176-97-AR (R4), specified in 40 CFR 75, Subpart G. Notifications, monitoring Plans, Initial Certification and Recertification Applications, Quarterly Reports, Opacity Reports, Petitions to the Administrator, and Retired Unit Petitions shall be submitted as specified in Subpart G - reporting requirements. (See Attachment E)

iv. Excess emissions for affected facilities using a CEMS for measuring SO_2 are defined as: (Regulation 2.16, section 4.1.9.3)

1) Any three-hour period during which the average emissions (arithmetic average of three contiguous one-hour periods) of SO_2 as measured by a CEMS exceed the applicable standard; or

2) Any 30 operating day period during which the average emissions (arithmetic average of all one-hour periods during the 30 operating days) of SO_2 as measured by a CEMS exceed the applicable standard.

c. **PM**

i. The owner or operator shall identify all periods of exceeding a PM emission standard during a quarterly reporting period. The report shall include the following:

1) Emission Unit ID number and emission point ID number;
2) The date and duration (including the start and stop time) during which a deviation occurred;
3) The magnitude of excess emissions;
4) Description of the deviation and summary information on the cause or reason for excess emissions;
5) Corrective action taken to minimize the extent and duration of each excess emissions event;

6) Measures implemented to prevent reoccurrence of the situation that resulted in excess PM emissions; or
7) If no deviations occur during a quarterly reporting period, the report shall contain a negative declaration.

ii. The owner or operator shall submit a written report of excess emissions and the nature and cause of the excess emissions if known. See Specific Condition S3.a.ii.

d. **Opacity**

i. The owner or operator shall identify all periods of exceeding an opacity standard during a quarterly reporting period. The report shall include the following:

1) Any deviation from the requirement to perform daily (or monthly, if required) visible emission surveys or Method 9 tests and documented reason;
2) Any deviation from the requirement to record the results of each VE survey and Method 9 test performed and documented reason;
3) The number, date, and time of each VE Survey where visible emissions were observed and the results of the Method 9 test performed;
4) Identification of all periods of exceeding an opacity standard;
5) Description of any corrective action taken for each exceedance of the opacity standard; or
6) If no deviations occur during a quarterly reporting period, the report shall contain a negative declaration.

ii. The owner or operator shall comply with the reporting requirements for the Acid Rain Permit No.176-97-AR (R4), specified in 40 CFR 75, Subpart G. Notifications, monitoring Plans, Initial Certification and Recertification Applications, Quarterly Reports, Opacity Reports, Petitions to the Administrator, and Retired Unit Petitions shall be submitted as specified in Subpart G - reporting requirements. (See Attachment E) (Regulation 6.47, section 3.4 and 3.5 referencing 40 CFR Parts 75 and 76)

iii. For coal silos (E4):

The owner or operator shall identify all periods of exceeding an opacity standard during a quarterly reporting period. The report shall include the following:

1) Emission Unit ID number, Stack ID number, and/or Emission point ID number;
2) The beginning and ending date of the reporting period;

3) The date, time and results of each exceedance of the opacity standard;
4) Description of any corrective action taken for each exceedance.

e. **TAC**

i. The owner or operator shall identify all periods of exceeding a TAC emission standard during a quarterly reporting period. The report shall include the following:

1) Emission Unit ID number and emission point ID number;
2) Identification of all periods during which a deviation occurred;
3) A description, including the magnitude, of the deviation;
4) If known, the cause of the deviation;
5) A description of all corrective actions taken to abate the deviation; and
6) If no deviations occur during a quarterly reporting period, the report shall contain a negative declaration.

ii. See Plantwide Requirements S2.b.

f. **HAP** (40 CFR 63, Subpart UUUUU)

i. The owner or operator shall comply with 40 CFR 63, Subpart UUUUU (See Attachment A) no later than April 16, 2016.

ii. Report normal pH range of reactant material in the FGD and normal range of any other parameters verified as having a direct effect on Hg emission within 30 days of establishing the normal range.

iii. The owner or operator shall identify all periods of the activated carbon injection rate are less than the minimum injection rate, or the pH of the reactant material in the FGD are out of normal range, or anytime other verified parameters are outside of their normal range, and any corrective action taken for each exceedance.

g. **BART** (40 CFR 52, Subpart S)

The owner or operator shall report any periods of time where the process was operating and both PJFF baghouse and ESP were not operating.

S4. **Testing** (Regulation 2.16, section 4.1.9.1)

a. **Control efficiency determination**

The owner or operator shall conduct performance test for the new EGU control device C27 and C28, according to the testing requirements in Attachment B, C, and G and Attachment C.[43,44] (Regulation 2.16, section 4.1.9.1)

U2 Comments

1. Boiler (E3) has TAC emission standards since its EA Demonstration was based on controlled PTE. If the controlled PTE for the TAC is less than de minimis level, De Minimis is listed as the basis for the limit. If the controlled PTE for the TAC is greater than de minimis level, modeling results were used to calculate risk value to compare to the EA Goals. In this case, controlled PTE is used as the basis for the limit. TAC emissions for the coal silos (E4) are de minimis according to Regulation 5.21, section 2.1. The TAC emission limits determined by de minimis values shall be updated each time when the District revises the BAC/de minimis values for these TACs. The current de minimis values per TAC list revised on 10/14/2013 are as the following:

TAC Name	CAS #	De minimis values (lb/hr)	De minimis values (lb/yr)
Benzene	71-43-2	0.243	216
Bromoform	75-25-2	0.4914	437
Chloroform	67-66-3	0.02322	20.6
Methylene chloride	75-09-2	54	48,000
Tetrachloroethylene (Perc)	127-18-4	2.079	1,848
Toluene	108-88-3	2700	2,400,000
Xylene	1330-20-7	54	48,000
Hydrochloric acid	7647-01-0	10.8	9,600

[43] Per an EPA rule change ("Restructuring of the Stationary Source Audit Program." Federal Register 75:176 (September 13, 2010) pp 55636-55657), if an audit sample is required by the test method, sources became responsible for obtaining the audit samples directly from accredited audit sample suppliers, not the regulatory agencies.

[44] This unit was modified under construction permit 34595-12-C. According to permit 34595-12-C, the source is required to conduct stack tests to obtain the actual emission factors and control efficiencies.

Emission Unit U3: Electric Utility Steam Generating Unit (EGU) – Unit 3

U3 Applicable Regulations:

FEDERALLY ENFORCEABLE REGULATIONS		
Regulation	**Title**	**Applicable Sections**
6.02	Emission Monitoring for Existing Sources	1, 2, 5, 6, 7, 8, 9, 10, 11, 12, 13, 14, 15, 16, 17, 18
6.09	Standards of Performance for Existing Process Operations	1, 2, 3, 5
6.42	Reasonably Available Control Technology Requirements for Major Volatile Organic Compound- and Nitrogen Oxides-Emitting Facilities	1, 2, 3, 4, 5
6.47	Federal Acid Rain Program for Existing Sources Incorporated by Reference	1, 2, 3, 4, 5
7.06	Standards of Performance for New Indirect Heat Exchangers	1, 2, 3, 4.1.2, 4.2, 5.1.2, 6, 7, 8
7.08	Standards of Performance for New Process Operations	1, 2, 3, 5
40 CFR 60, Subpart D	Standards of Performance for Fossil-Fuel Fired Steam Generators for Which Construction is Commenced After August 17, 1971	60.40, 60.41, 60.42(a), 60.43, 60.44, 60.45, 60.46
40 CFR 64	Compliance Assurance Monitoring for Major Stationary Sources	64.1 through 64.10
40 CFR 68	Chemical Accident Prevention Provisions	68.1 through 68.220
40 CFR 72	Permits Regulation	Subparts A, B, C, D, E, F, G, H, I
40 CFR 73	Sulfur Dioxide Allowance System	Subparts A, B, C, D, E, F, G
40 CFR 75	Continuous Emission Monitoring	Subparts A, B, C, D, E, F, G
40 CFR 76	Acid Rain Nitrogen Oxides Emission Reduction Program	76.1, 76.2, 76.3, 76.4, 76.5, 76.7, 76.8, 76.9, 76.11, 76.13, 76.14, 76.15, Appendix A, Appendix B
40 CFR 77	Excess Emissions	77.1, 77.2, 77.3, 77.4, 77.5, 77.6
40 CFR 78	Appeals Procedures for Acid Rain Program	78.1, 78.2, 78.3, 78.4, 78.5, 78.6, 78.8, 78.9, 78.10, 78.11, 78.13, 78.14, 78.15, 78.16, 78.17, 78.18, 78.19, 78.20
40 CFR 63, Subpart UUUUU	National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units (EGU MACT)	63.9980 through 63.10042

DISTRICT ONLY ENFORCEABLE REGULATIONS		
Regulation	**Title**	**Applicable Sections**
5.00	Definitions	1, 2
5.01	General Provisions	1 through 2
5.02	Adoption of National Emission Standards for Hazardous Air Pollutants	1, 3.95 and 4
5.14	Hazardous Air Pollutants and Source Categories	1, 2
5.15	Chemical Accident Prevention Provisions	1, 2
5.20	Methodology for Determining Benchmark Ambient Concentration of a Toxic Air Contaminant	1 through 6
5.21	Environmental Acceptability for Toxic Air Contaminants	1 through 5
5.22	Procedures for Determining the Maximum Ambient Concentration of a Toxic Air Contaminant	1 through 5
5.23	Categories of Toxic Air Contaminants	1 through 6
7.02	Federal New Source Performance Standards Incorporated by Reference	1.1, 1.8, 2, 3, 4, 5

U3 Equipment:[45]

Emission Point	Description	Applicable Regulation	Control ID	Stack ID
E5	One (1) dry bottom, wall-fired boiler, rated capacity 4,204 MMBtu/hr, make Babcock & Wilcox, using pulverized coal as a primary fuel and natural gas as secondary fuel.	5.00, 5.01, 5.02, 5.14, 5.20, 5.21, 5.22, 5.23, 6.02, 6.42, 6.47,7.02, 7.06 40 CFR 60, D 40 CFR 64, 40 CFR 72-73, 40 CFR 75-78, 40 CFR 63, UUUUU	C7, C8[a], C22	S3[a]
			C7, C22, C29[b], C39[b]	S4[b]
E6	Four (4) coal silos, make American Air Filter, controlled by a centrifugal dust collector and equipped with four (4) coal mills, make Babcock & Wilcox.	5.00, 5.01, 5.20, 5.21, 5.22, 5.23, 6.09	C9	S7

[45] This unit was modified under construction permit 215-01 (SCR), 225-01 (Ammonia tanks), and 34595-12-C.

Emission Point	Description	Applicable Regulation	Control ID	Stack ID
Note a: The existing FGD and stack (C8, S3) will shut down before April 16, 2016, the compliance date when this unit has to comply with 40 CFR 63, Subpart UUUUU. Note b: The new FGD, HAP PM control and existing stack (C29, C39, and S4) will replace C8 and S3. These new control devices need to be in full operation no later than April 16, 2016, the compliance date when this unit has to comply with 40 CFR 63, Subpart UUUUU.[46]				

U3 Control Devices:

Before compliance with 40 CFR 63, Subpart UUUUU, Unit 3 uses the following control devices:

ID	Description	Performance Indicator	Stack ID
C7	One (1) custom-built electrostatic precipitator (ESP) for PM control, make Western Precipitator Division	PM emission data from PM CEMS (if PM CEMS is not used to demonstrate compliance)	S3
C8	One (1) Flue Gas Desulfurization (FGD) unit for SO_2 control using limestone scrubbing liquor, make Combustion Engineering	N/A[47]	
C9	One (1) centrifugal dust collector, make American Air Filter	N/A[48]	S7
C22	One (1) Selective Catalytic Reduction (SCR), make Babcock Borsig Power, and the associated ammonia storage tanks.[49]	N/A[47]	S3

After compliance with 40 CFR 63, Subpart UUUUU, Unit 3 uses the following control devices:

ID	Description	Performance Indicator	Stack ID
C7	One (1) custom-built electrostatic precipitator (ESP) for PM control, make Western Precipitator Division	N/A[47]	S4

[46] On June 20, 2016, LG&E submitted a notification for initial startup of PJFF (C29) and FGD (C39) for U3. These control devices went into service on June 8, 2016.

[47] This unit is equipped with CEMS for NOx, SO2, and PM. According to the District's letter dated November 1, 2005, parametric monitoring of the ESP, FGD, and PJFF for this unit is removed as such monitoring would no longer be required for demonstration of compliance. On July 22, 2016, LG&E reported the normal pressure drop range for U3 PJFF, 2 – 6 inches of water, established during 90 consecutive operating days.

[48] For the coal silos (E6), the owner or operator has shown, by worst-case calculations without allowance for a control device, that the hourly uncontrolled PM emission standard cannot be exceeded; therefore, no additional monitoring, recordkeeping, or reporting is required to demonstrate compliance with the applicable PM standards specified in Regulation 6.09 and 7.08 is required for this emission point.

[49] The two ammonia storage tanks are housed in a roof-covered building which has secondary containment for about 66,000 gallons of liquid ammonia (110% of one tank) if a release occurs. The ammonia, under pressure, will be a liquid but will convert to a gas after it is released. The building and tanks contain alarms and leak detection devices. Ammonia from either tank can be used by either Unit 3 or Unit 4 SCR System.

<table>
<tr><th>ID</th><th>Description</th><th>Performance Indicator</th><th>Stack ID</th></tr>
<tr><td>C39</td><td>One (1) Flue Gas Desulfurization (FGD) unit for SO_2 control using limestone scrubbing liquor, make Babcock Power Environmental</td><td>N/A[47]</td><td></td></tr>
<tr><td>C9</td><td>One (1) centrifugal dust collector, make American Air Filter</td><td>N/A[48]</td><td>S7</td></tr>
<tr><td>C22</td><td>One (1) Selective Catalytic Reduction (SCR), make Babcock Borsig Power</td><td>N/A[47]</td><td rowspan="2">S4</td></tr>
<tr><td>C29</td><td>One (1) HAP particulate matter control system, consists of: one (1) powdered activated carbon (PAC) injection system; one (1) dry sorbent injection system; liquid additive system(s); and one (1) pulse-jet fabric filter (PJFF) baghouse used for collecting PM from the boiler and PAC and dry sorbent injection system. PJFF make Clyde Bergemann Power Group, model Structural Pulse Jet.</td><td>PM Control:
PM emission data from PM CEMS (if PM CEMS is not used to demonstrate compliance)

Hg control:
(1) Minimum PAC injection rate;[50]
(2) pH of reactant in FGD, 4.8-6.4;
(3) Hg emission data from Sorbent Traps</td></tr>
</table>

[50] In a letter dated October 4, 2016, LG&E demonstrated that in certain circumstance EGUs at this plant can meet the MACT mercury standard at zero PAC injection rate. Therefore the source is allowed to use flexible mercury control measures, including PAC injection or liquid additive system, to achieve compliance with MACT mercury standard.

U3 Specific Conditions

S1. **Standards**[51] (Regulation 2.16, section 4.1.1)

a. **NO_x**

i. The owner or operator shall not allow the average NO_x emissions to exceed the alternate contemporaneous emission limitation of 0.46 lb/MMBtu of heat input on an annual average basis, as specified in Acid Rain Permit No.176-97-AR (R4). (See Acid Rain Permit Attachment) (Regulation 6.47, section 3.5 referencing 40 CFR Part 76)

ii. The owner or operator shall not exceed the NO_x RACT emissions standard of 0.52 lb/MMBtu of heat input based on a rolling 30-day average. (See NO_x RACT Attachment) (Regulation 6.42, section 4.3)

iii. When combusting natural gas, the owner or operator shall not cause to be discharged into the atmosphere any gases which contain nitrogen oxides expressed as nitrogen dioxide in excess of 86 ng/J (0.20 lb/MMBtu) heat input on a 3-hour rolling average. (Regulation 7.06, section 6.1.1) (40 CFR 60.44(a)(1))

iv. When combusting coal, the owner or operator shall not cause to be discharged into the atmosphere any gases which contain nitrogen oxides expressed as nitrogen dioxide in excess of 300 ng/J (0.70 lb/MMBtu) heat input on a 3-hour rolling average. (Regulation 7.06, section 6.1.3) (40 CFR 60.44(a)(3))

v. When natural gas and coal are burned simultaneously in any combination, the applicable standard is determined by proration using the following equation: (40 CFR 60.44(b))

$$PS_{NOx} = \frac{x(86) + z(300)}{(x + z)}$$

Where,

PS_{NOx} = Prorates standard for NOx when burning different fuels simultaneously, in ng/J heat input derived from all fossil fuels fired;
x = Percentage of total heat input from gaseous fossil fuel
z = Percentage of total heat from solid fossil fuel (except lignite)

vi. The owner or operator shall install, maintain, calibrate and operate a continuous emission monitoring system (CEMS) for the measurement or calculation of nitrogen oxides in the flue gas. (Regulation 6.02, section

[51] The emission standards, monitoring, record keeping, and reporting requirements only apply to the boiler E5 (not the coal silos E6) if not indicated.

6.1.3) (NO_x RACT Plan) (Regulation 6.47, section 3.4 referencing 40 CFR 75.10(a)(2))

b. **SO_2**

i. The owner or operator shall not exceed 0.8 lb/MMBtu heat input for combustion of natural gas and 1.2 lb/MMBtu heat input for combustion of coal based on a three hour rolling average. (Regulation 7.06, section 5.1.2) (40 CFR 60.43(a)(2)))

ii. When natural gas and coal fuels are burned simultaneously in any combination, the applicable standard is determined by proration using the following equation: (Regulation 2.16, section 4.1.1)

$$PS_{SO2} = \frac{x(0.8) + z(1.2)}{(x + z)}$$

Where,

PS_{SO2} = Prorates standard for SO_2 when burning different fuels simultaneously, in lb/MMBtu heat input derived from all fossil fuels fired;

x = Percentage of total heat input from gaseous fossil fuel

z = Percentage of total heat from solid fossil fuel (except lignite)

iii. Compliance shall be based on the total heat input from all fossil fuels burned, including gaseous fuels. (40 CFR 60.43(c))

iv. The owner or operator shall comply with the annual SO_2 emission allowances specified in Acid Rain Permit No.176-97-AR (R4). (See Acid Rain Permit Attachment) (Regulation 6.47, section 3.2 referencing 40 CFR Part 73)

v. The owner or operator shall operate and maintain the FGD, as recommended by the manufacturer, at all times the respective boiler is in operation, including periods of startup, shutdown, and malfunction, in a manner consistent with good air pollution control practice to meet the standards.[52] (Regulation 2.16, section 4.1.1)

vi. The owner or operator shall install, maintain, calibrate and operate a continuous emission monitoring system (CEMS) for the measurement of sulfur dioxide in the flue gas. (Regulation 6.02, section 6.1.2) (Regulation 6.47, section 3.4 referencing 40 CFR 75.10(a)(1))

[52] The SO2 emissions cannot meet the standards uncontrolled. The owner or operator is required to operate the control devices to meet the applicable limits for SO2.

c. **PM**

i. The owner or operator shall not exceed an allowable particulate emission rate of 0.10 lbs/MMBtu heat input based on a three hour rolling average. (Regulation 7.06, section 4.1.2)

ii. The owner or operator shall not cause to be discharged into the atmosphere from any affected facility any gases that Contain PM in excess of 43 ng/J heat input (0.10 lb/MMBtu) derived from fossil fuel. (40 CFR 60.42(a)(1))

iii. The owner or operator shall operate and maintain the PM control devices, as recommended by the manufacturer, at all times the respective boiler is in operation, including periods of startup, shutdown, and malfunction, in a manner consistent with good air pollution control practice to meet the standards. Following commissioning of the PJFF baghouses, the owner or operator may elect to operate, turn down, or turn off the ESP to ensure the efficient operation of the PJFF baghouse.[53] (Regulation 2.16, section 4.1.1)

iv. The company shall follow one of the two options below to demonstrate compliance with PM standards:

Compliance Options	PM	Opacity	Control Device Performance indication
Option 1	Certified PM CEMS	VE/Method 9, or Certified COMS	N/A
Option 2	Annual testing	Certified COMS	PM CEMS

v. For the coal silos (E6), the owner or operator shall not exceed an allowable particulate emission rate of 82.95 lbs/hr from four coal silos combined based on actual operating hours in a calendar day.[54] (Regulation 6.09, section 3.2)

d. **Opacity**

i. The owner or operator shall not cause the emission into the open air of particulate matter from any indirect heat exchanger which is greater than 20% opacity, except for emissions from an indirect heat exchanger during building a new fire for the period required to bring the boiler up to operating conditions provided the method used is that recommended by the

[53] The PM emissions cannot meet the standards uncontrolled. The owner or operator is required to operate the control devices to meet the applicable limits for PM.

[54] For the coal silos (E6), the owner or operator has shown, by worst-case calculations without allowance for a control device, that the hourly uncontrolled PM emission standard cannot be exceeded; therefore, no additional monitoring, recordkeeping, or reporting is required to demonstrate compliance with the applicable PM standards specified in Regulation 6.09 and 7.08 is required for this emission point.

manufacturer and the time does not exceed the manufacturer's recommendations. (Regulation 7.06, section 4.2)

ii. The company shall follow one of the two options in the table under Specific Condition S1.c.iv to demonstrate compliance with opacity standards.

iii. The owner or operator shall not cause the emission into the open air of particulate matter that exhibit greater than 20% opacity except for one six-minute period per hour of not more that 27%. (40 CFR 60.42(a)(2))

iv. For the coal silos (E6), the owner or operator shall not allow visible emissions to equal or exceed 20% opacity. (Regulation 6.09, section 3.1) (Regulation 7.08, section 3.1.1)

e. **TAC**

i. The owner or operator shall not allow TAC emissions from boiler E5 to exceed the TAC emission standards determined based upon the EA Demonstration provided to the District.[55] (Regulation 5.21, section 4.2 and section 4.3) (See Comment 1)

TAC Name	CAS #	TAC Limits Determination (lbs/yr)	Basis of Limits
Naphthalene	91-20-3	22.6	Controlled PTE
Formaldehyde	50-00-0	95.8	Controlled PTE
Hydrogen fluoride	7664-39-3	18,240	Controlled PTE
Arsenic compounds	7440-38-2	363	Controlled PTE
Cadmium compounds	7440-43-9	57.4	Controlled PTE
Chromium VI	7440-47-3	128.7	Controlled PTE
Chromium III	16065-83-1	295	Controlled PTE
Cobalt compounds	7440-48-4	76.5	Controlled PTE
Lead compounds	7439-92-1	453	Controlled PTE
Manganese compounds	7439-96-5	578	Controlled PTE
Nickel compounds	7440-02-0	418	Controlled PTE
Sulfuric acid	7664-93-9	161,726	Controlled PTE
Benzene	71-43-2	De minimis values (See Comment 1)	De Minimis
Bromoform	75-25-2		De Minimis
Chloroform	67-66-3		De Minimis
Methylene chloride	75-09-2		De Minimis
Tetrachloroethylene (Perc)	127-18-4		De Minimis
Toluene	108-88-3		De Minimis
Xylene	1330-20-7		De Minimis

[55] This table for TAC emission standards has been revised to exclude Category 3 and 4 TACs for existing sources and use "de minimis values", instead of actual numbers for current de minimis levels, as emission standards.

TAC Name	CAS #	TAC Limits Determination	
		(lbs/yr)	Basis of Limits
Hydrochloric acid	7647-01-0		De Minimis

ii. See Plantwide Requirements S1.b.

f. **HAP** (40 CFR 63, Subpart UUUUU)

The owner or operator shall comply with 40 CFR 63, Subpart UUUUU (See Attachment A) no later than April 16, 2016.[56]

g. **112(r) Regulated Substances** (Regulation 5.15)

If anhydrous ammonia is present at the stationary source in an amount greater than the threshold quantity specified in Regulation 5.15, the owner or operator shall comply with the requirements specified in Regulation 5.15, including the requirement to submit a Risk Management Plan in a method and format as specified by the District and EPA.[57] (Construction Permit 225-01-C)

h. **BART** (40 CFR 52, Subpart S)

i. The owner or operator shall install sorbent injection to control SO_3 emissions and continue to utilize PJFF baghouse and/or existing ESP to control PM emissions for this unit.[58] (40 CFR 52.920(e) refer to Kentucky Regional Haze SIP)

ii. The owner or operator shall not allow H_2SO_4 emissions from this unit to exceed 64.3 lbs/hr based on actual operating houses in a calendar day. (40 CFR 52.920(e) refer to Kentucky Regional Haze SIP)

S2. **Monitoring and Record Keeping** (Regulation 2.16, sections 4.1.9.1 and 4.1.9.2)

The owner or operator shall maintain the following records for a minimum of 5 years and make the records readily available to the District upon request.

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[56] According to 40 CFR 63.9984(b), the compliance date for an existing EGU is April 16, 2015. LG&E requested a year extension and the District has approved the request for the extension per (40 CFR 63.6(i)(4)(i)). Therefore the compliance date for the EGUs under this construction is April 16, 2016.

[57] The two ammonia storage tanks are housed in a roof-covered building which has secondary containment for about 66,000 gallons of liquid ammonia (110% of one tank) if a release occurs. The ammonia, under pressure, will be a liquid but will convert to a gas after it is released. The building and tanks contain alarms and leak detection devices. Ammonia from either tank can be used by either Unit 3 or Unit 4 SCR System.

[58] On March 30, 2012, EPA finalized a limited approval and a limited disapproval of the Kentucky state implementation plan submitted on June 25, 2008 and May 28, 2010. According to 40 CFR 52.920(e), the owner or operator shall meet BART requirements summarized in Table 7.5.3-2 of the Commonwealth's May 28, 2010 submittal. A sorbent injection system has been installed for this unit in 2015.

a. **NO_x**

i. The owner or operator shall demonstrate compliance with NO_x RACT Plan limits by continuous emissions monitors (CEMs) as specified in the NO_x RACT Plan. (See NO_x RACT Attachment) (Regulation 6.42, section 4.3)

ii. The owner or operator shall keep a record identifying all deviations from the requirements of the NO_x RACT Plan.

iii. The owner or operator shall comply with the NO_x compliance plan requirements specified in the attached Acid Rain Permit, No.176-97-AR (R4). These record keeping requirements shall be determined in accordance with the Title IV Phase II Acid Rain Permit and are specified in 40 CFR Part 75 Subpart F. (See AppendixA to NOx RACT Plan) (Regulation 6.47, section 3.4 and 3.5 referencing 40 CFR Parts 75 and 76)

iv. The owner or operator shall record on an hourly basis all NO_x emission data specified in 40 CFR Part 75, section 75.57(d). For each NO_x emission rate (in lb/mmBtu) measured by a NO_x-diluent monitoring system, or, if applicable, for each NO_x concentration (in ppm) measured by a NO_x concentration monitoring system used to calculate NO_x mass emissions under 40 CFR 75.71(a)(2), record the following data as measured and reported from the certified primary monitor, certified back-up monitor, or other approved method of emissions determination:

1) Component-system identification code, as provided in 40 CFR 75.53 (including identification code for the moisture monitoring system, if applicable); (40 CFR 75.57(d)(1))

2) Date and hour; (40 CFR 75.57(d)(2))

3) Hourly average NO_x concentration (ppm, rounded to the nearest tenth) and hourly average NO_x concentration (ppm, rounded to the nearest tenth) adjusted for bias if bias adjustment factor required, as provided in 40 CFR 75.24(d); (40 CFR 75.57(d)(3))

4) Hourly average diluent gas concentration (for NO_x -diluent monitoring systems, only, in units of percent O_2 or percent CO_2, rounded to the nearest tenth); (40 CFR 75.57(d)(4))

5) If applicable, the hourly average moisture content of the stack gas (percent H_2O, rounded to the nearest tenth). If the continuous moisture monitoring system consists of wet- and dry-basis oxygen analyzers, also record both the hourly wet- and dry-basis oxygen readings (in percent O2, rounded to the nearest tenth); (40 CFR 75.57(d)(5))

6) Hourly average NO_x emission rate (for NO_x -diluent monitoring systems only, in units of lb/mmBtu, rounded to the nearest thousandth); (40 CFR 75.57(d)(6))

7) Hourly average NO_x emission rate (for NO_x -diluent monitoring systems only, in units of lb/mmBtu, rounded to the nearest thousandth), adjusted for bias if bias adjustment factor is required, as provided in 40 CFR 75.24(d). The requirement to report hourly NO_x emission rates to the nearest thousandth shall not affect NO_x compliance determinations under part 76 of this chapter; compliance with each applicable emission limit under part 76 shall be determined to the nearest hundredth pound per million Btu; (40 CFR 75.57(d)(7))

8) Percent monitoring system data availability (recorded to the nearest tenth of a percent), for the NO_x -diluent or NO_x concentration monitoring system, and, if applicable, for the moisture monitoring system, calculated pursuant to 40 CFR 75.32; (40 CFR 75.57(d)(8))

9) Method of determination for hourly average NO_x emission rate or NO_x concentration and (if applicable) for the hourly average moisture percentage, using Codes 1–55 in Table 4a of 40 CFR 75.57; and (40 CFR 75.57(d)(9))

10) Identification codes for emissions formulas used to derive hourly average NO_x emission rate and total NO_x mass emissions, as provided in 40 CFR 75.53, and (if applicable) the F-factor used to convert NO_x concentrations into emission rates. (40 CFR 75.57(d)(10))

v. A CEMS for measuring either oxygen (O_2) or carbon dioxide (CO_2) in the flue gases shall be installed, calibrated, maintained, and operated by the owner or operator. The owner or operator shall use the conversion procedures specified in Regulation 7.06, sections 7.5 and 7.6 for NO_x, SO_2, and PM. (Regulation 7.06, section 7.4)

vi. The owner or operator shall monitor the NO_x emissions, the NO_x allowances, as specified in the Clean Air Interstate Rule or the applicable NO_x cap and trade program(s) in effect.

vii. For performance evaluations under 40 CFR 60.13(c) and calibration checks under 40 CFR 60.13(d), the following procedures shall be used: (40 CFR 60.45(c))

1) Methods 6, 7, and 3B of appendix A of this part, as applicable, shall be used for the performance evaluations of SO_2 and NO_X continuous monitoring systems. Acceptable alternative methods for Methods 6, 7, and 3B of appendix A of this part are given in 40 CFR 60.46(d). (40 CFR 60.45(c)(1))

2) Sulfur dioxide or nitric oxide, as applicable, shall be used for preparing calibration gas mixtures under Performance Specification 2 of appendix B to this part. (40 CFR 60.45(c)(2))

3) For affected facilities burning fossil fuel(s), the span value for a continuous monitoring system measuring the opacity of emissions shall be 80, 90, or 100 percent. For a continuous monitoring system measuring sulfur oxides or NO_X the span value shall be determined using one of the following procedures: (40 CFR 60.45(c)(3))

(a) Except as provided under paragraph 40 CFR 60.45(c)(3)(ii), SO_2 and NO_X span values shall be determined as follows: (40 CFR 60.45(c)(3)(i))

Fossil fuel	In parts per million	
	Span value for SO_2	Span value for NO_X
Gas	Not Applicable	500.
Liquid	1,000	500.
Solid	1,500	1,000.

(b) As an alternative to meeting the requirements of paragraph 40 CFR 60.45(c)(3)(i), the owner or operator of an affected facility may elect to use the SO_2 and NO_X span values determined according to sections 2.1.1 and 2.1.2 in appendix A to part 75 of this chapter. (40 CFR 60.45(c)(3)(ii))

viii. The conversion procedures in 40 CFR 60.45(e) and (f) shall be used to convert the continuous monitoring data into units of the applicable standards. (40 CFR 60.45(e) and (f))

1) For any CEMS installed under paragraph (a) of this section, the following conversion procedures shall be used to convert the continuous monitoring data into units of the applicable standards (ng/J, lb/MMBtu): (40 CFR 60.45(e))

(a) When a CEMS for measuring O_2 is selected, the measurement of the pollutant concentration and O_2 concentration shall each be on a consistent basis (wet or dry). Alternative procedures approved by the Administrator shall be used when measurements are on a wet basis. When measurements are on a dry basis, the following conversion procedure shall be used: (40 CFR 60.45(e)(1))

$$E = CF\left(\frac{20.9}{(20.9 - \%O_2)}\right)$$

Where E, C, F, and $\%O_2$ are determined under paragraph (f) of this section.

(b) When a CEMS for measuring CO_2 is selected, the measurement of the pollutant concentration and CO_2 concentration shall each be on a consistent basis (wet or dry) and the following conversion procedure shall be used: (40 CFR 60.45(e)(2))

$$E = CF_c\left(\frac{100}{\%CO_2}\right)$$

Where E, C, F_c and $\%CO_2$ are determined under paragraph (f) of this section.

2) The values used in the equations under paragraphs (e)(1) and (2) of this section are derived as follows: (40 CFR 60.45(f))

(a) E = pollutant emissions, ng/J (lb/MMBtu). (40 CFR 60.45(f)(1))

(b) C = pollutant concentration, ng/dscm (lb/dscf), determined by multiplying the average concentration (ppm) for each one-hour period by 4.15×10^{4} M ng/dscm per ppm (2.59×10^{-9}M lb/dscf per ppm) where M = pollutant molecular weight, g/g-mole (lb/lb-mole). M = 64.07 for SO_2 and 46.01 for NO_X. (40 CFR 60.45(f)(2))

(c) $\%O_2$, $\%CO_2$= O_2 or CO_2 volume (expressed as percent), determined with equipment specified under paragraph (a) of this section. (40 CFR 60.45(f)(3))

(d) F, F_c= a factor representing a ratio of the volume of dry flue gases generated to the calorific value of the fuel combusted (F), and a factor representing a ratio of the volume of CO_2 generated to the calorific value of the fuel combusted (F_c), respectively. Values of F and F_c are given as follows: (40 CFR 60.45(f)(4))

(i) For anthracite coal as classified according to ASTM

D388 (incorporated by reference, see 40 CFR 60.17), F = 2,723 × 10 $^{-17}$ dscm/J (10,140 dscf/MMBtu) and F_c= 0.532 × 10 $^{-17}$ scm CO_2/J (1,980 scf CO_2/MMBtu). (40 CFR 60.45(f)(4)(i))

(ii) For subbituminous and bituminous coal as classified according to ASTM D388 (incorporated by reference, see 40 CFR 60.17), F = 2.637 × 10 $^{-7}$ dscm/J (9,820 dscf/MMBtu) and F_c= 0.486 × 10 $^{-7}$ scm CO_2/J (1,810 scf CO_2/MMBtu). (40 CFR 60.45(f)(4)(ii))

(iii) For liquid fossil fuels including crude, residual, and distillate oils, F = 2.476 × 10 $^{-7}$ dscm/J (9,220 dscf/MMBtu) and F_c= 0.384 × 10 $^{-7}$ scm CO_2/J (1,430 scf CO_2/MMBtu). (40 CFR 60.45(f)(4)(iii))

(iv) For gaseous fossil fuels, F = 2.347 × 10 $^{-7}$ dscm/J (8,740 dscf/MMBtu). For natural gas, propane, and butane fuels, F_c= 0.279 × 10 $^{-7}$ scm CO_2/J (1,040 scf CO_2/MMBtu) for natural gas, 0.322 × 10 $^{-7}$ scm CO_2/J (1,200 scf CO_2/MMBtu) for propane, and 0.338 × 10 $^{-7}$ scm CO_2/J (1,260 scf CO_2/MMBtu) for butane. (40 CFR 60.45(f)(4)(iv))

(v) For bark F = 2.589 × 10 $^{-7}$ dscm/J (9,640 dscf/MMBtu) and F_c= 0.500 × 10 $^{-7}$ scm CO_2/J (1,840 scf CO_2/MMBtu). For wood residue other than bark F = 2.492 × 10 $^{-7}$ dscm/J (9,280 dscf/MMBtu) and F_c= 0.494 × 10 $^{-7}$ scm CO_2/J (1,860 scf CO_2/MMBtu). (40 CFR 60.45(f)(4)(v))

(vi) For lignite coal as classified according to ASTM D388 (incorporated by reference, see 40 CFR 60.17), F = 2.659 × 10 $^{-7}$ dscm/J (9,900 dscf/MMBtu) and F_c= 0.516 × 10 $^{-7}$ scm CO_2/J (1,920 scf CO_2/MMBtu). (40 CFR 60.45(f)(4)(vi))

(e) The owner or operator may use the following equation to determine an F factor (dscm/J or dscf/MMBtu) on a dry basis (if it is desired to calculate F on a wet basis, consult the Administrator) or Fc factor (scm CO_2/J, or scf CO_2/MMBtu) on either basis in lieu of the F or F_c factors specified in paragraph (f)(4) of this section: (40 CFR 60.45(f)(5))

$$F = 10^{-6} \frac{[227.2\ (\%H) + 95.5\ (\%C) + 35.6\ (\%S) + 8.7\ (\%N) - 28.7\ (\%O)]}{GCV}$$

$$F_c = \frac{2.0 \times 10^{-5}\ (\%C)}{GCV\ (SI\ units)}$$

$$F = 10^{-6} \frac{[3.64\ (\%H) + 1.53\ (\%C) + 0.57\ (\%S) + 0.14\ (\%N) - 0.46\ (\%O)]}{GCV\ (English\ units)}$$

$$F_c = \frac{20.0\ (\%C)}{GCV\ (SI\ units)}$$

$$F_c = \frac{321 \times 10^{3}\ (\%C)}{GCV\ (English\ units)}$$

(i) %H, %C, %S, %N, and %O are content by weight of hydrogen, carbon, sulfur, nitrogen, and O_2(expressed as percent), respectively, as determined on the same basis as GCV by ultimate analysis of the fuel fired, using ASTM D3178 or D3176 (solid fuels), or computed from results using ASTM D1137, D1945, or D1946 (gaseous fuels) as applicable. (These five methods are incorporated by reference, see 40 CFR 60.17.) (40 CFR 60.45(f)(5)(i))

(ii) GVC is the gross calorific value (kJ/kg, Btu/lb) of the fuel combusted determined by the ASTM test methods D2015 or D5865 for solid fuels and D1826 for gaseous fuels as applicable. (These three methods are incorporated by reference, see 40 CFR 60.17.) (40 CFR 60.45(f)(5)(ii))

(iii) For affected facilities which fire both fossil fuels and nonfossil fuels, the F or Fc value shall be subject to the Administrator's approval. (40 CFR 60.45(f)(5)(iii))

(f) For affected facilities firing combinations of fossil fuels or fossil fuels and wood residue, the F or Fc factors determined by paragraphs (f)(4) or (f)(5) of this section shall be prorated in accordance with the applicable formula as follows: (40 CFR 60.45(f)(6))

$$F = \sum_{i=1}^{n} X_i F_i \quad \text{or} \quad F_c = \sum_{i=1}^{n} X_i \left(F_c\right)_i$$

Where:
X_i= Fraction of total heat input derived from each type of fuel (e.g. natural gas, bituminous coal, wood residue, etc.);
F_i or $(F_c)_i$= Applicable F or F_c factor for each fuel type determined in accordance with paragraphs (f)(4) and (f)(5) of this section; and
n = Number of fuels being burned in combination.

b. **SO_2**

i. The owner or operator shall maintain hourly records of SO_2 emissions as specified in Regulation 6.02, section 6.1.2.

ii. The owner or operator shall record on an hourly basis all SO_2 emission data specified in 40 CFR 75.57(c):

1) For SO_2 concentration during unit operation, as measured and reported from each certified primary monitor, certified back-up monitor, or other approved method of emissions determination: (40 CFR 75.57(c)(1))

(a) Component-system identification code, as provided in 40 CFR 75.53; (40 CFR 75.57(c)(1)(i))

(b) Date and hour; (40 CFR 75.57(c)(1)(ii))

(c) Hourly average SO_2 concentration (ppm, rounded to the nearest tenth); (40 CFR 75.57(c)(1)(iii))

(d) Hourly average SO_2 concentration (ppm, rounded to the nearest tenth), adjusted for bias if bias adjustment factor is required, as provided in 40 CFR 75.24(d); (40 CFR 75.57(c)(1)(iv))

(e) Percent monitor data availability (recorded to the nearest tenth of a percent), calculated pursuant to 40 CFR 75.32; and (40 CFR 75.57(c)(1)(v))

(f) Method of determination for hourly average SO_2 concentration using Codes 1–55 in Table 4a of 40 CFR 75.57. (40 CFR 75.57(c)(1)(vi))

2) For flow rate during unit operation, as measured and reported from each certified primary monitor, certified back-up monitor, or other approved method of emissions determination: (40 CFR 75.57(c)(2))

(a) Component-system identification code, as provided in 40 CFR 75.53; (40 CFR 75.57(c)(2)(i))

(b) Date and hour; (40 CFR 75.57(c)(2)(ii))

(c) Hourly average volumetric flow rate (in scfh, rounded to the nearest thousand); (40 CFR 75.57(c)(2)(iii))

(d) Hourly average volumetric flow rate (in scfh, rounded to the nearest thousand), adjusted for bias if bias adjustment factor required, as provided in 40 CFR 75.24(d); (40 CFR 75.57(c)(2)(iv))

(e) Percent monitor data availability (recorded to the nearest tenth of a percent) for the flow monitor, calculated pursuant to 40 CFR 75.32; and (40 CFR 75.57(c)(2)(v))

(f) Method of determination for hourly average flow rate using Codes 1–55 in Table 4a of 40 CFR 75.57. (40 CFR 75.57(c)(2)(vi))

3) For SO_2 mass emission rate during unit operation, as measured and reported from the certified primary monitoring system(s), certified redundant or non-redundant back-up monitoring system(s), or other approved method(s) of emissions determination: (40 CFR 75.57(c)(4))

(a) Date and hour; (40 CFR 75.57(c)(4)(i))

(b) Hourly SO_2 mass emission rate (lb/hr, rounded to the nearest tenth); (40 CFR 75.57(c)(4)(ii))

(c) Hourly SO_2 mass emission rate (lb/hr, rounded to the nearest tenth), adjusted for bias if bias adjustment factor required, as provided in 40 CFR 75.24(d); and (40 CFR 75.57(c)(4)(iii))

(d) Identification code for emissions formula used to derive hourly SO2 mass emission rate from SO2 concentration and flow and (if applicable) moisture data in paragraphs (c)(1), (c)(2), and (c)(3) of 40 CFR 75.57, as provided in 40 CFR 75.53. (40 CFR 75.57(c)(4)(iv))

iii. For performance evaluations under 40 CFR 60.13(c) and calibration checks under 40 CFR 60.13(d), the following procedures shall be used: (40 CFR 60.45(c))

1) Methods 6, 7, and 3B of appendix A of this part, as applicable, shall be used for the performance evaluations of SO_2 and NO_X continuous monitoring systems. Acceptable alternative methods for Methods 6, 7, and 3B of appendix A of this part are given in 40 CFR 60.46(d). (40 CFR 60.45(c)(1))

2) Sulfur dioxide or nitric oxide, as applicable, shall be used for preparing calibration gas mixtures under Performance Specification 2 of appendix B to this part. (40 CFR 60.45(c)(2))

3) For affected facilities burning fossil fuel(s), the span value for a continuous monitoring system measuring the opacity of emissions shall be 80, 90, or 100 percent. For a continuous monitoring system measuring sulfur oxides or NO_X the span value shall be determined using one of the following procedures: (40 CFR 60.45(c)(3))

(a) Except as provided under paragraph 40 CFR 60.45(c)(3)(ii), SO_2 and NO_X span values shall be determined as follows: (40 CFR 60.45(c)(3)(i))

Fossil fuel	In parts per million	
	Span value for SO_2	Span value for NO_X
Gas	Not Applicable	500.
Liquid	1,000	500.
Solid	1,500	1,000.

(b) As an alternative to meeting the requirements of paragraph 40 CFR 60.45(c)(3)(i), the owner or operator of an affected facility may elect to use the SO_2 and NO_X span values determined according to sections 2.1.1 and 2.1.2 in appendix A to part 75 of this chapter. (40 CFR 60.45(c)(3)(ii))

iv. The conversion procedures in 40 CFR 60.45(e) and (f) shall be used to convert the continuous monitoring data into units of the applicable standards. (40 CFR 60.45(e) and (f))

1) For any CEMS installed under paragraph (a) of this section, the following conversion procedures shall be used to convert the continuous monitoring data into units of the applicable standards (ng/J, lb/MMBtu): (40 CFR 60.45(e))

(a) When a CEMS for measuring O_2 is selected, the measurement of the pollutant concentration and O_2 concentration shall each be on a consistent basis (wet or dry). Alternative procedures approved by the Administrator shall be used when measurements are on a wet basis. When measurements are on a dry basis, the following conversion procedure shall be used: (40 CFR 60.45(e)(1))

$$E = CF\left(\frac{20.9}{(20.9 - \%O_2)}\right)$$

Where E, C, F, and $\%O_2$ are determined under paragraph (f) of this section.

(b) When a CEMS for measuring CO_2 is selected, the measurement of the pollutant concentration and CO_2 concentration shall each be on a consistent basis (wet or dry) and the following conversion procedure shall be used: (40 CFR 60.45(e)(2))

$$E = CF_c\left(\frac{100}{\%CO_2}\right)$$

Where E, C, F_c and $\%CO_2$ are determined under paragraph (f) of this section.

2) The values used in the equations under paragraphs (e)(1) and (2) of this section are derived as follows: (40 CFR 60.45(f))

(a) E = pollutant emissions, ng/J (lb/MMBtu). (40 CFR 60.45(f)(1))

(b) C = pollutant concentration, ng/dscm (lb/dscf), determined by multiplying the average concentration (ppm) for each one-hour period by 4.15×10^{4} M ng/dscm per ppm (2.59×10^{-9}M lb/dscf per ppm) where M = pollutant molecular weight, g/g-mole (lb/lb-mole). M = 64.07 for SO_2 and 46.01 for NO_X. (40 CFR 60.45(f)(2))

(c) $\%O_2$, $\%CO_2$= O_2 or CO_2 volume (expressed as percent), determined with equipment specified under paragraph (a) of this section. (40 CFR 60.45(f)(3))

(d) F, F_c= a factor representing a ratio of the volume of dry flue gases generated to the calorific value of the fuel combusted (F), and a factor representing a ratio of the volume of CO_2 generated to the calorific value of the fuel combusted (F_c), respectively. Values of F and F_c are given as follows: (40 CFR 60.45(f)(4))

(i) For anthracite coal as classified according to ASTM

D388 (incorporated by reference, see 40 CFR 60.17), F = 2,723 × 10 $^{-17}$ dscm/J (10,140 dscf/MMBtu) and F_c= 0.532 × 10 $^{-17}$ scm CO_2/J (1,980 scf CO_2/MMBtu). (40 CFR 60.45(f)(4)(i))

(ii) For subbituminous and bituminous coal as classified according to ASTM D388 (incorporated by reference, see 40 CFR 60.17), F = 2.637 × 10 $^{-7}$ dscm/J (9,820 dscf/MMBtu) and F_c= 0.486 × 10 $^{-7}$ scm CO_2/J (1,810 scf CO_2/MMBtu). (40 CFR 60.45(f)(4)(ii))

(iii) For liquid fossil fuels including crude, residual, and distillate oils, F = 2.476 × 10 $^{-7}$ dscm/J (9,220 dscf/MMBtu) and F_c= 0.384 × 10 $^{-7}$ scm CO_2/J (1,430 scf CO_2/MMBtu). (40 CFR 60.45(f)(4)(iii))

(iv) For gaseous fossil fuels, F = 2.347 × 10 $^{-7}$ dscm/J (8,740 dscf/MMBtu). For natural gas, propane, and butane fuels, F_c= 0.279 × 10 $^{-7}$ scm CO_2/J (1,040 scf CO_2/MMBtu) for natural gas, 0.322 × 10 $^{-7}$ scm CO_2/J (1,200 scf CO_2/MMBtu) for propane, and 0.338 × 10 $^{-7}$ scm CO_2/J (1,260 scf CO_2/MMBtu) for butane. (40 CFR 60.45(f)(4)(iv))

(v) For bark F = 2.589 × 10 $^{-7}$ dscm/J (9,640 dscf/MMBtu) and F_c= 0.500 × 10 $^{-7}$ scm CO_2/J (1,840 scf CO_2/MMBtu). For wood residue other than bark F = 2.492 × 10 $^{-7}$ dscm/J (9,280 dscf/MMBtu) and F_c= 0.494 × 10 $^{-7}$ scm CO_2/J (1,860 scf CO_2/MMBtu). (40 CFR 60.45(f)(4)(v))

(vi) For lignite coal as classified according to ASTM D388 (incorporated by reference, see 40 CFR 60.17), F = 2.659 × 10 $^{-7}$ dscm/J (9,900 dscf/MMBtu) and F_c= 0.516 × 10 $^{-7}$ scm CO_2/J (1,920 scf CO_2/MMBtu). (40 CFR 60.45(f)(4)(vi))

(e) The owner or operator may use the following equation to determine an F factor (dscm/J or dscf/MMBtu) on a dry basis (if it is desired to calculate F on a wet basis, consult the Administrator) or Fc factor (scm CO_2/J, or scf CO_2/MMBtu) on either basis in lieu of the F or F_c factors specified in paragraph (f)(4) of this section: (40 CFR 60.45(f)(5))

$$F = 10^{-6}\frac{[227.2\ (\%H) + 95.5\ (\%C) + 35.6\ (\%S) + 8.7\ (\%N) - 28.7\ (\%O)]}{GCV}$$

$$F_c = \frac{2.0\times10^{-5}\ (\%C)}{GCV\ (SI\ units)}$$

$$F = 10^{-6}\frac{[3.64\ (\%H) + 1.53\ (\%C) + 0.57\ (\%S) + 0.14\ (\%N) - 0.46\ (\%O)]}{GCV\ (English\ units)}$$

$$F_c = \frac{20.0\ (\%C)}{GCV\ (SI\ units)}$$

$$F_c = \frac{321\times10^{3}\ (\%C)}{GCV\ (English\ units)}$$

(i) %H, %C, %S, %N, and %O are content by weight of hydrogen, carbon, sulfur, nitrogen, and O_2(expressed as percent), respectively, as determined on the same basis as GCV by ultimate analysis of the fuel fired, using ASTM D3178 or D3176 (solid fuels), or computed from results using ASTM D1137, D1945, or D1946 (gaseous fuels) as applicable. (These five methods are incorporated by reference, see 40 CFR 60.17.) (40 CFR 60.45(f)(5)(i))

(ii) GVC is the gross calorific value (kJ/kg, Btu/lb) of the fuel combusted determined by the ASTM test methods D2015 or D5865 for solid fuels and D1826 for gaseous fuels as applicable. (These three methods are incorporated by reference, see 40 CFR 60.17.) (40 CFR 60.45(f)(5)(ii))

(iii) For affected facilities which fire both fossil fuels and nonfossil fuels, the F or Fc value shall be subject to the Administrator's approval. (40 CFR 60.45(f)(5)(iii))

(f) For affected facilities firing combinations of fossil fuels or fossil fuels and wood residue, the F or Fc factors determined by paragraphs (f)(4) or (f)(5) of this section shall be prorated in accordance with the applicable formula as follows: (40 CFR 60.45(f)(6))

$$F = \sum_{i=1}^{n} X_i F_i \quad \text{or} \quad F_c = \sum_{i=1}^{n} X_i \left(F_c\right)_i$$

Where:
X_i= Fraction of total heat input derived from each type of fuel (e.g. natural gas, bituminous coal, wood residue, etc.);
F_i or $(F_c)_i$= Applicable F or F_c factor for each fuel type determined in accordance with paragraphs (f)(4) and (f)(5) of this section; and
n = Number of fuels being burned in combination.

c. **PM**

i. The company shall follow one of the two options below to demonstrate compliance with PM standards:

1) Option 1: the owner or operator shall install, maintain, calibrate, and operate a PM CEMS for each steam generating unit.[59,60] (Regulation 2.16, section 4.1.1) (40 CFR 64)

(a) The use of PM CEMS as the measurement technique must be appropriate for the stack conditions.

(b) The PM CEMS must be installed, operated and maintained in accordance with the manufacturer's recommendations, applicable requirements in Subpart D, and General Provisions in 40 CFR 60.7 – 60.13.

(c) The PM CEMS must be certified in accordance with Performance Specification 11, Specifications and Test Procedures for Particulate Matter Continuous Emission Monitoring Systems at Stationary Sources, found in 40 CFR 60, Appendix B.

(d) A quality assurance/quality control program must be implemented in accordance with procedures in 40 CFR 60, Appendix F, Procedure 2 (Quality Assurance Requirements for Particulate Matter Continuous Emission Monitoring Systems at Stationary Sources).

[59] According to LG&E's request, PM CEMS have been installed, calibrated, maintained, and operated for Unit 1. LG&E requested permission to remove COMS for Unit 3 and 4 under provisions in 40 CFR 60.13(i)(1), "Alternative monitoring requirements when installation of a continuous monitoring system or monitoring device specified by this part would not provide accurate measurements due to liquid water or other interferences caused by substances in the effluent gases." LG&E's proposal for Unit 3 and 4 was accepted in a letter from EPA dated Feb. 28, 2007. The District accordingly approved LG&E's request for removing COMS for Unit 1 and 2 providing PM CEMS are appropriately installed for these units.

[60] The coal-fired boilers are subject to 40 CFR Part 64 - Compliance Assurance Monitoring (CAM) for Major Stationary Source since SO2, PM, and NOx emissions from each of the boilers may be greater than the major source threshold and control devices are required to achieve compliance with standards. On 5/21/2014, LG&E submitted a revised CAM Plan in which SO2 and NOx CEMS are used for compliance demonstration. PM CEMS is used to demonstrate compliance or provide an indication of continuous PM control.

(e) Compliance with the particulate matter emission limit promulgated at 40 CFR 60.42(a) will be based upon three-hour rolling average periods during source operation.

(f) LG&E must comply with all applicable recordkeeping and reporting requirements under Subpart D and under the General Provisions in 40 CFR 60.7 – 60.13. Quarterly excess emission reports must be submitted, and PM excess emissions shall be reported based upon three-hour rolling averages during source operation.

2) Option 2: the owner or operator shall conduct an annual EPA Reference Method 5 performance test following the testing requirements in Attachment B, Specific Condition b.ii.

ii. If certified PM CEMS (Option 1) is used to demonstrate compliance with PM standards, the owner or operator shall record on an hourly basis all PM emission data, in lb/MMBtu, from PM CEMS.[61] (40 CFR 64)

iii. If annual PM testing (Option 2) is used to demonstrate compliance with PM standards, the owner or operator shall use PM CEMS as a performance indicator of continuous normal operation of the PM control devices and do the following:[61] (40 CFR 64)

1) The owner or operator shall monitor and record all PM emission data from PM CEMS, which is used as the indicator of normal operation of the PM control devices.

2) The owner or operator shall maintain daily records of any periods of time where the process was operating and the PM control devices were not operating or a declaration that the PM control devices operated at all times that day when the process was operating.

3) If there is any time that the PM control devices are bypassed or not in operation when the process is operating, then the owner or operator shall keep a record of the following for each bypass event:

(a) Date;
(b) Start time and stop time;
(c) Identification of the control devices and process equipment;

[61] The coal-fired boilers are subject to 40 CFR Part 64 - Compliance Assurance Monitoring (CAM) for Major Stationary Source since SO2, PM, and NOx emissions from each of the boilers may be greater than the major source threshold and control devices are required to achieve compliance with standards. On 5/21/2014, LG&E submitted a revised CAM Plan in which SO2 and NOx CEMS are used for compliance demonstration. PM CEMS is used to demonstrate compliance or provide an indication of continuous PM control.

(d) PM emissions during the bypass in lb/hr;
(e) Summary of the cause or reason for each bypass event;
(f) Corrective action taken to minimize the extent or duration of the bypass event; and
(g) Measures implemented to prevent reoccurrence of the situation that resulted in the bypass event.

d. **Opacity**

i. If certified COMS is used to demonstrate compliance with opacity standards, the owner or operator shall record on an hourly basis all opacity from COMS.[62]

ii. If VE/Method 9 is used to demonstrate compliance with opacity standards, in order for the owner or operator to use its VE observations to satisfy the opacity monitoring requirement, the following conditions must be met:[62] (EPA Letter, 2007)

1) On a weekly basis, the owner or operator shall attempt to perform VE observations in accordance with procedures in EPA Method 9.

2) On the weeks when it is possible to collect unit-specific VE data, at least one hour of Method 9 data shall be collected for each unit.

3) Records of the Method 9 readings shall be submitted with the quarterly excess emission reports for PM emissions.

iii. The owner or operator shall keep a record of every Method 9 test performed or the reason why it could not be performed that day.

iv. An owner or operator of an affected facility subject to an opacity standard under 40 CFR 60.42 that elects to not use a COMS because the affected facility burns only fuels as specified under paragraph (b)(1) of 40 CFR 60.45, monitors PM emissions as specified under paragraph (b)(5) of 40 CFR 60.45, or monitors CO emissions as specified under paragraph (b)(6) of 40 CFR 60.45, shall conduct a performance test using Method 9 of appendix A-4 of this part and the procedures in 40 CFR 60.11 to demonstrate compliance with the applicable limit in 40 CFR 60.42 by April 29, 2011 or within 45 days after stopping use of an existing COMS,

[62] According to LG&E's request, PM CEMS have been installed, calibrated, maintained, and operated for Unit 1. LG&E requested permission to remove COMS for Unit 3 and 4 under provisions in 40 CFR 60.13(i)(1), "Alternative monitoring requirements when installation of a continuous monitoring system or monitoring device specified by this part would not provide accurate measurements due to liquid water or other interferences caused by substances in the effluent gases." LG&E's proposal for Unit 3 and 4 was accepted in a letter from EPA dated Feb. 28, 2007. The District accordingly approved LG&E's request for removing COMS for Unit 1 and 2 providing PM CEMS are appropriately installed for these units.

whichever is later, and shall comply with either paragraph (b)(7)(i), (b)(7)(ii), or (b)(7)(iii) of 40 CFR 60.45. The observation period for Method 9 of appendix A-4 of this part performance tests may be reduced from 3 hours to 60 minutes if all 6-minute averages are less than 10 percent and all individual 15-second observations are less than or equal to 20 percent during the initial 60 minutes of observation. The permitting authority may exempt owners or operators of affected facilities burning only natural gas from the opacity monitoring requirements. (40 CFR 60.45(b)(7))

1) Except as provided in paragraph (b)(7)(ii) or (b)(7)(iii) of 40 CFR 60.45, the owner or operator shall conduct subsequent Method 9 of appendix A–4 of this part performance tests using the procedures in paragraph (b)(7) of 40 CFR 60.45 according to the applicable schedule in paragraphs (b)(7)(i)(A) through (b)(7)(i)(D) of 40 CFR 60.45, as determined by the most recent Method 9 of appendix A–4 of this part performance test results.

   (a) If no visible emissions are observed, a subsequent Method 9 of appendix A–4 of this part performance test must be completed within 12 calendar months from the date that the most recent performance test was conducted; (40 CFR 60.45(b)(7)(i)(A))

   (b) If visible emissions are observed but the maximum 6-minute average opacity is less than or equal to 5 percent, a subsequent Method 9 of appendix A–4 of this part performance test must be completed within 6 calendar months from the date that the most recent performance test was conducted; (40 CFR 60.45(b)(7)(i)(B))

   (c) If the maximum 6-minute average opacity is greater than 5 percent but less than or equal to 10 percent, a subsequent Method 9 of appendix A–4 of this part performance test must be completed within 3 calendar months from the date that the most recent performance test was conducted; or (40 CFR 60.45(b)(7)(i)(C))

   (d) If the maximum 6-minute average opacity is greater than 10 percent, a subsequent Method 9 of appendix A-4 of this part performance test must be completed within 45 calendar days from the date that the most recent performance test was conducted. (40 CFR 60.45(b)(7)(i)(D))

2) If the maximum 6-minute opacity is less than 10 percent during the most recent Method 9 of appendix A–4 of this part performance test, the owner or operator may, as an alternative to performing subsequent Method 9 of appendix A–4 of this part performance test,

elect to perform subsequent monitoring using Method 22 of appendix A–7 of this part according to the procedures specified in paragraphs (b)(7)(ii)(A) and (B) of 40 CFR 60.45. (40 CFR 60.45(b)(7)(ii))

(a) The owner or operator shall conduct 10 minute observations (during normal operation) each operating day the affected facility fires fuel for which an opacity standard is applicable using Method 22 of appendix A-7 of this part and demonstrate that the sum of the occurrences of any visible emissions is not in excess of 5 percent of the observation period (i.e., 30 seconds per 10 minute period). If the sum of the occurrence of any visible emissions is greater than 30 seconds during the initial 10 minute observation, immediately conduct a 30 minute observation. If the sum of the occurrence of visible emissions is greater than 5 percent of the observation period (i.e., 90 seconds per 30 minute period), the owner or operator shall either document and adjust the operation of the facility and demonstrate within 24 hours that the sum of the occurrence of visible emissions is equal to or less than 5 percent during a 30 minute observation (i.e., 90 seconds) or conduct a new Method 9 of appendix A-4 of this part performance test using the procedures in paragraph (b)(7) of 40 CFR 60.45 within 45 calendar days according to the requirements in 40 CFR 60.46(b)(3). (40 CFR 60.45(b)(7)(ii)(A))

(b) If no visible emissions are observed for 30 operating days during which an opacity standard is applicable, observations can be reduced to once every 7 operating days during which an opacity standard is applicable. If any visible emissions are observed, daily observations shall be resumed. (40 CFR 60.45(b)(7)(ii)(B))

3) If the maximum 6-minute opacity is less than 10 percent during the most recent Method 9 of appendix A–4 of this part performance test, the owner or operator may, as an alternative to performing subsequent Method 9 of appendix A–4 performance tests, elect to perform subsequent monitoring using a digital opacity compliance system according to a site-specific monitoring plan approved by the Administrator. The observations shall be similar, but not necessarily identical, to the requirements in paragraph (b)(7)(ii) of 40 CFR 60.45. For reference purposes in preparing the monitoring plan, see OAQPS "Determination of Visible Emission Opacity from Stationary Sources Using Computer-Based Photographic Analysis Systems." This document is available from the U.S. Environmental

Protection Agency (U.S. EPA); Office of Air Quality and Planning Standards; Sector Policies and Programs Division; Measurement Policy Group (D243–02), Research Triangle Park, NC 27711. This document is also available on the Technology Transfer Network (TTN) under Emission Measurement Center Preliminary Methods. (40 CFR 60.45(b)(7)(iii)

v. The owner or operator of an affected facility subject to the opacity limits in 40 CFR 60.42 that elects to monitor emissions according to the requirements in 40 CFR 60.45(b)(7) shall maintain records according to the requirements specified in paragraphs (h)(1) through (3) of 40 CFR 60.45, as applicable to the visible emissions monitoring method used. (40 CFR 60.45(h))

1) For each performance test conducted using Method 9 of appendix A–4 of this part, the owner or operator shall keep the records including the information specified in paragraphs (h)(1)(i) through (iii) of 40 CFR 60.45. (40 CFR 60.45(h)(1))

(a) Dates and time intervals of all opacity observation periods; (40 CFR 60.45(h)(1)(i))

(b) Name, affiliation, and copy of current visible emission reading certification for each visible emission observer participating in the performance test; and (40 CFR 60.45(h)(1)(ii))

(c) Copies of all visible emission observer opacity field data sheets; (40 CFR 60.45(h)(1)(iii))

2) For each performance test conducted using Method 22 of appendix A–4 of this part, the owner or operator shall keep the records including the information specified in paragraphs (h)(2)(i) through (iv) of 40 CFR 60.45. (40 CFR 60.45(h)(2))

(a) Dates and time intervals of all visible emissions observation periods; (40 CFR 60.45(h)(2)(i))

(b) Name and affiliation for each visible emission observer participating in the performance test; (40 CFR 60.45(h)(2)(ii))

(c) Copies of all visible emission observer opacity field data sheets; and (40 CFR 60.45(h)(2)(iii))

(d) Documentation of any adjustments made and the time the adjustments were completed to the affected facility operation by the owner or operator to demonstrate compliance with the applicable monitoring requirements. (40 CFR 60.45(h)(2)(iv))

3) For each digital opacity compliance system, the owner or operator shall maintain records and submit reports according to the requirements specified in the site-specific monitoring plan approved by the Administrator. (40 CFR 60.45(h)(3))

vi. <u>For coal silos (E6):</u>

1) The owner or operator shall conduct a weekly one-minute visible emissions survey, during normal operation, of the PM Emission Points (stacks). For Emission Points without observed visible emissions during twelve consecutive operating weeks, the owner or operator may elect to conduct a monthly one-minute visible emission survey, during normal operation.

2) At Emission Points where visible emissions are observed, the owner or operator shall initiate corrective action within eight hours of the initial observation. If the visible emissions persist, the owner or operator shall perform or cause to be performed a Method 9 for stack emissions within 24 hours of the initial observation. If the opacity standard is exceeded, the owner or operator shall report the exceedance to the District, according to Regulation 1.07, and take all practicable steps to eliminate the exceedance.

3) The owner or operator shall maintain records, monthly, of the results of all visible emissions surveys and tests. Records of the results of any visible emissions survey shall include the date of the survey, the name of the person conducting the survey, whether or not visible emissions were observed, and what if any corrective action was performed. If an emission point is not being operated during a given month, then no visible emission survey needs to be performed and a negative declaration shall be entered in the record.

e. **TAC**

i. The owner or operator shall monthly calculate and record TAC emissions for this unit in order to demonstrate compliance with the TAC emission standards.

ii. See Plantwide Requirements S2.b.

f. **HAP** (40 CFR 63, Subpart UUUUU)

i. The owner or operator shall comply with 40 CFR 63, Subpart UUUUU (See Attachment A) no later than April 16, 2016.

ii. The owner or operator shall establish a site-specific minimum activated carbon injection rate for PAC injection system according to Attachment B, Specific Condition a.i. The owner or operator shall monitor and record the activated carbon injection rate during each operating day. [63]

iii. The owner or operator shall monitor and record all Hg emission data from the Hg sorbent traps, which is used as the indicator of normal operation of the Hg control measures.

iv. The owner or operator shall monitor and record the pH of the reactant material in the FGD and any other parameters verified as having a direct effect on Hg emissions during each operating day, which is (are) used as the indicator(s) of normal operation of Hg control measures. [64]

v. The owner or operator shall maintain records of which Hg control devices/measure was being used during each operating day.

g. **112(r) Regulated Substances (Regulation 5.15)**

If anhydrous ammonia is present at the stationary source in an amount greater than the threshold quantity specified in Regulation 5.15, the owner or operator shall monitor the processes and keep records as required by Regulation 5.15. (Construction Permit 225-01-C)

h. **BART** (40 CFR 52, Subpart S)

i. The owner or operator shall maintain daily records of the hours of operation.

ii. The owner or operator shall, monthly, calculate and record the H_2SO_4 emissions on an average hourly basis for each operating calendar day.

S3. **Reporting** (Regulation 2.16, section 4.1.9.3)

The owner or operator shall submit quarterly compliance reports that include the information in this section.

[63] In a letter dated October 4, 2016, LG&E demonstrated that in certain circumstance EGUs at this plant can meet the MACT mercury standard at zero PAC injection rate. Therefore the source is allowed to use flexible mercury control measures, including PAC injection or liquid additive system, to achieve compliance with MACT mercury standard.

[64] LG&E has established normal pH range per monitoring records during consecutive 180 days. On 10/20/2016, LG&E reported that the normal pH range for this unit is 4.8 – 6.4.

a. **NO_x**

i. The owner or operator shall identify all periods of exceeding a NO_x emission standard during a quarterly reporting period. The quarterly compliance report shall include the following:

1) Emission Unit ID number and emission point ID number;
2) Identification of all periods during which a deviation occurred;
3) A description, including the magnitude, of the deviation;
4) If known, the cause of the deviation;
5) A description of all corrective actions taken to abate the deviation; and
6) If no deviations occur during a quarterly reporting period, the report shall contain a negative declaration.

ii. The owner or operator shall submit a written report of excess emissions and the nature and cause of the excess emissions if known. The averaging period used for data reporting should correspond to the averaging period specified in the emission test method used to determine compliance with an emission standard for the pollutant/source category in question. All quarterly reports shall be postmarked by the 30th day following the end of each calendar quarter. The required report shall include: (Regulation 6.02, section 16.1)

1) For gaseous measurements, the summary shall consist of hourly averages in the units of the applicable standard. The hourly averages shall not appear in the written summary, but shall be made available electronically. (Regulation 6.02, section 16.3)

2) The data and time identifying each period during which the continuous monitoring system was inoperative, except for zero and span checks, and the nature of system repairs or adjustment shall be reported. Proof of continuous monitoring system performance whenever system repairs or adjustments have been made is required. (Regulation 6.02, section 16.4)

3) When no excess emissions have occurred and the continuous monitoring systems have been inoperative, repaired, or adjusted, such information shall be included in the report. (Regulation 6.02, section 16.5)

4) Owners or operators of affected facilities shall maintain a file of all information reported in the quarterly summaries, and all other data collected either by the continuous monitoring system or as necessary to convert monitoring data to the units of the applicable standard for a minimum of two years from the date of collection of such data or submission of such summaries. (Regulation 6.02, section 16.6)

iii. The owner or operator shall comply with the reporting requirements for the Acid Rain Permit No.176-97-AR (R4), specified in 40 CFR 75, Subpart G. Notifications, Monitoring Plans, Initial Certification and Recertification Applications, Quarterly Reports, Opacity Reports, Petitions to the Administrator, and Retired Unit Petitions shall be submitted as specified in Subpart G - reporting requirements. (See Attachment E)

iv. The owner or operator shall comply with the reporting requirements for the Title IV NO_x Budget Emission Limitation, 0.46 lb/MMBtu, as specified in 40 CFR Part 76.

v. Excess emissions for affected facilities using a CEMS for measuring NO_X are defined as: (40 CFR 60.45(g)(3))

1) For affected facilities electing not to comply with 40 CFR 60.44(e), any three-hour period during which the average emissions (arithmetic average of three contiguous one-hour periods) exceed the applicable standards in 40 CFR 60.44; or (40 CFR 60.45(g)(3)(i))

2) For affected facilities electing to comply with 40 CFR 60.44(e), any 30 operating day period during which the average emissions (arithmetic average of all one-hour periods during the 30 operating days) of NO_X as measured by a CEMS exceed the applicable standard in 40 CFR 60.44. (40 CFR 60.45(g)(3)(ii))

b. **SO_2**

i. The owner or operator shall identify all periods of exceeding a SO_2 emission standard during a quarterly reporting period. The report shall include the following:

1) Emission Unit ID number and emission point ID number;
2) Identification of all periods during which a deviation occurred;
3) A description, including the magnitude, of the deviation;
4) If known, the cause of the deviation;
5) A description of all corrective actions taken to abate the deviation; and
6) If no deviations occur during a quarterly reporting period, the report shall contain a negative declaration.

ii. The owner or operator shall submit a written report of excess emissions and the nature and cause of the excess emissions if known. See Specific Condition S3.a.ii.

iii. The owner or operator shall comply with the reporting requirements for the Acid Rain Permit No.176-97-AR (R4), specified in 40 CFR 75, Subpart G. Notifications, monitoring Plans, Initial Certification and Recertification Applications, Quarterly Reports, Opacity Reports, Petitions to the Administrator, and Retired Unit Petitions shall be submitted as specified in Subpart G - reporting requirements. (See Attachment E)

iv. Excess emissions for affected facilities are defined as: (40 CFR 60.45(g)(2))

1) For affected facilities electing not to comply with 40 CFR 60.43(d), any three-hour period during which the average emissions (arithmetic average of three contiguous one-hour periods) of SO_2 as measured by a CEMS exceed the applicable standard in 40 CFR 60.43; or (40 CFR 60.45(g)(2)(i))

2) For affected facilities electing to comply with 40 CFR 60.43(d), any 30 operating day period during which the average emissions (arithmetic average of all one-hour periods during the 30 operating days) of SO_2 as measured by a CEMS exceed the applicable standard in 40 CFR 60.43. (40 CFR 60.45(g)(2)(ii))

c. **PM**

i. The owner or operator shall identify all periods of exceeding a PM emission standard during a quarterly reporting period. The report shall include the following:

1) Emission Unit ID number and emission point ID number;
2) The date and duration (including the start and stop time) during which a deviation occurred;
3) The magnitude of excess emissions;
4) Description of the deviation and summary information on the cause or reason for excess emissions;
5) Corrective action taken to minimize the extent and duration of each excess emissions event;
6) Measures implemented to prevent reoccurrence of the situation that resulted in excess PM emissions; or
7) If no deviations occur during a quarterly reporting period, the report shall contain a negative declaration.

ii. The owner or operator shall submit a written report of excess emissions and the nature and cause of the excess emissions if known. See Specific Condition S3.a.ii.

iii. Excess emissions for affected facilities using a CEMS for measuring PM are defined as any boiler operating day period during which the average emissions (arithmetic average of all operating one-hour periods) exceed the applicable standards in 40 CFR 60.42. (40 CFR 60.45(g)(4))

d. **Opacity**

i. The owner or operator shall identify all periods of exceeding an opacity standard during a quarterly reporting period. The report shall include the following:

1) Any deviation from the requirement to perform daily (or monthly, if required) visible emission surveys or Method 9 tests and documented reason;
2) Any deviation from the requirement to record the results of each VE survey and Method 9 test performed and documented reason;
3) The number, date, and time of each VE Survey where visible emissions were observed and the results of the Method 9 test performed;
4) Identification of all periods of exceeding an opacity standard;
5) Description of any corrective action taken for each exceedance of the opacity standard; or
6) If no deviations occur during a quarterly reporting period, the report shall contain a negative declaration.

ii. The owner or operator shall comply with the reporting requirements for the Acid Rain Permit No.176-97-AR (R4), specified in 40 CFR 75, Subpart G. Notifications, monitoring Plans, Initial Certification and Recertification Applications, Quarterly Reports, Opacity Reports, Petitions to the Administrator, and Retired Unit Petitions shall be submitted as specified in Subpart G - reporting requirements. (See Attachment E) (Regulation 6.47, section 3.4 and 3.5 referencing 40 CFR Parts 75 and 76)

iii. Excess emissions are defined as any six-minute period during which the average opacity of emissions exceeds 20 percent opacity, except that one six-minute average per hour of up to 27 percent opacity need not be reported. (40 CFR 60.45(g)(1))

iv. <u>For coal silos (E6)</u>:

The owner or operator shall identify all periods of exceeding an opacity standard during a quarterly reporting period. The report shall include the following:

1) Emission Unit ID number, Stack ID number, and/or Emission point ID number;
2) The beginning and ending date of the reporting period;

3) The date, time and results of each exceedance of the opacity standard;
4) Description of any corrective action taken for each exceedance.

e. **TAC**

i. The owner or operator shall identify all periods of exceeding a TAC emission standard during a quarterly reporting period. The report shall include the following:

1) Emission Unit ID number and emission point ID number;
2) Identification of all periods during which a deviation occurred;
3) A description, including the magnitude, of the deviation;
4) If known, the cause of the deviation;
5) A description of all corrective actions taken to abate the deviation; and
6) If no deviations occur during a quarterly reporting period, the report shall contain a negative declaration.

ii. See Plantwide Requirements S2.b.

f. **HAP** (40 CFR 63, Subpart UUUUU)

i. The owner or operator shall comply with 40 CFR 63, Subpart UUUUU (See Attachment A) no later than <u>April 16, 2016</u>.

ii. Report normal pH range of reactant material in the FGD and normal range of any other parameters verified as having a direct effect on Hg emission within 30 days of establishing the normal range.

iii. The owner or operator shall identify all periods of the activated carbon injection rate are less than the minimum injection rate, or the pH of the reactant material in the FGD are out of normal range, or anytime other verified parameters are outside of their normal range, and any corrective action taken for each exceedance.

g. **112(r) Regulated Substances (Regulation 5.15)**

If anhydrous ammonia is present at the stationary source in an amount greater than the threshold quantity specified in Regulation 5.15, the owner or operator shall comply with the reporting requirements specified in Regulation 5.15. (Construction Permit 225-01-C)

h. **BART** (40 CFR 52, Subpart S)

The owner or operator shall identify all periods of exceeding a H_2SO_4 emission standard during a quarterly reporting period. The report shall include the following:

1) Emission Unit ID number and emission point ID number;
2) The date and duration (including the start and stop time) during which a deviation occurred;
3) The magnitude of excess emissions;
4) Description of the deviation and summary information on the cause or reason for excess emissions;
5) Corrective action taken to minimize the extent and duration of each excess emissions event;
6) Measures implemented to prevent reoccurrence of the situation that resulted in excess H_2SO_4 emissions; or
7) If no deviations occur during a quarterly reporting period, the report shall contain a negative declaration.

S4. **Testing** (Regulation 2.16, section 4.1.9.1)

a. **Control efficiency determination**

The owner or operator shall conduct performance test for the new EGU control device C29 and C39, according to the testing requirements in Attachment B, C, and G and Attachment C.[65,66] (Regulation 2.16, section 4.1.9.1)

U3 Comments

1. Boiler (E5) has TAC emission standards since its EA Demonstration was based on controlled PTE. If the controlled PTE for the TAC is less than de minimis level, De Minimis is listed as the basis of the limit. If the controlled PTE for the TAC is greater than de minimis level, modeling results were used to calculate risk value to compare to the EA Goals. In this case, controlled is used as the basis of the limit. TAC emissions for the coal silos (E6) are de minimis according to Regulation 5.21, section 2.1. The TAC emission limits determined by de minimis values shall be updated each time when the District revises the BAC/de minimis values for these TACs. The current de minimis values per TAC list revised on 10/14/2013 are as the following:

TAC Name	CAS #	De minimis values	
		(lb/hr)	(lb/yr)
Benzene	71-43-2	0.243	216

[65] Per an EPA rule change ("Restructuring of the Stationary Source Audit Program." Federal Register 75:176 (September 13, 2010) pp 55636-55657), if an audit sample is required by the test method, sources became responsible for obtaining the audit samples directly from accredited audit sample suppliers, not the regulatory agencies.

[66] According to permit 34595-12-C, the source is required to conduct stack tests to obtain the actual emission factors and control efficiencies.

TAC Name	CAS #	De minimis values	
		(lb/hr)	(lb/yr)
Bromoform	75-25-2	0.4914	437
Chloroform	67-66-3	0.02322	20.6
Methylene chloride	75-09-2	54	48,000
Tetrachloroethylene (Perc)	127-18-4	2.079	1,848
Toluene	108-88-3	2700	2,400,000
Xylene	1330-20-7	54	48,000
Hydrochloric acid	7647-01-0	10.8	9,600

Emission Unit U4: Electric Utility Steam Generating Unit (EGU) – Unit 4

U4 Applicable Regulations:

FEDERALLY ENFORCEABLE REGULATIONS		
Regulation	**Title**	**Applicable Sections**
6.02	Emission Monitoring for Existing Sources	1, 2, 5, 6, 7, 8, 9, 10, 11, 12, 13, 14, 15, 16, 17, 18
6.09	Standards of Performance for Existing Process Operations	1, 2, 3, 5
6.42	Reasonably Available Control Technology Requirements for Major Volatile Organic Compound- and Nitrogen Oxides-Emitting Facilities	1, 2, 3, 4, 5
6.47	Federal Acid Rain Program for Existing Sources Incorporated by Reference	1, 2, 3, 4, 5
7.06	Standards of Performance for New Indirect Heat Exchangers	1, 2, 3, 4.1.2, 4.2, 5.1.2, 6, 7, 8
7.08	Standards of Performance for New Process Operations	1, 2, 3, 5
40 CFR 60, Subpart D	Standards of Performance for Fossil-Fuel Fired Steam Generators for Which Construction is Commenced After August 17, 1971	60.40, 60.41, 60.42(a), 60.43, 60.44, 60.45, 60.46
40 CFR 64	Compliance Assurance Monitoring for Major Stationary Sources	64.1 through 64.10
40 CFR 68	Chemical Accident Prevention Provisions	68.1 through 68.220
40 CFR 72	Permits Regulation	Subparts A, B, C, D, E, F, G, H, I
40 CFR 73	Sulfur Dioxide Allowance System	Subparts A, B, C, D, E, F, G
40 CFR 75	Continuous Emission Monitoring	Subparts A, B, C, D, E, F, G
40 CFR 76	Acid Rain Nitrogen Oxides Emission Reduction Program	76.1, 76.2, 76.3, 76.4, 76.5, 76.7, 76.8, 76.9, 76.11, 76.13, 76.14, 76.15, Appendix A, Appendix B
40 CFR 77	Excess Emissions	77.1, 77.2, 77.3, 77.4, 77.5, 77.6
40 CFR 78	Appeals Procedures for Acid Rain Program	78.1, 78.2, 78.3, 78.4, 78.5, 78.6, 78.8, 78.9, 78.10, 78.11, 78.13, 78.14, 78.15, 78.16, 78.17, 78.18, 78.19, 78.20
40 CFR 63, Subpart UUUUU	National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units (EGU MACT)	63.9980 through 63.10042

DISTRICT ONLY ENFORCEABLE REGULATIONS		
Regulation	**Title**	**Applicable Sections**
5.00	Definitions	1, 2
5.01	General Provisions	1 through 2
5.02	Adoption of National Emission Standards for Hazardous Air Pollutants	1, 3.95 and 4
5.14	Hazardous Air Pollutants and Source Categories	1, 2
5.15	Chemical Accident Prevention Provisions	1, 2
5.20	Methodology for Determining Benchmark Ambient Concentration of a Toxic Air Contaminant	1 through 6
5.21	Environmental Acceptability for Toxic Air Contaminants	1 through 5
5.22	Procedures for Determining the Maximum Ambient Concentration of a Toxic Air Contaminant	1 through 5
5.23	Categories of Toxic Air Contaminants	1 through 6
7.02	Federal New Source Performance Standards Incorporated by Reference	1.1, 1.8, 2, 3, 4, 5

U4 Equipment:[67]

<table>
<tr><th>Emission Point</th><th>Description</th><th>Applicable Regulation</th><th>Control ID</th><th>Stack ID</th></tr>
<tr><td rowspan="2">E7</td><td rowspan="2">One (1) dry bottom, wall-fired boiler, rated capacity 5,025 MMBtu/hr, make Babcock & Wilcox, using pulverized coal as a primary fuel and natural gas as secondary fuel.</td><td rowspan="2">5.00, 5.01, 5.02, 5.14, 5.20, 5.21, 5.22, 5.23, 6.02, 6.42, 6.47,7.02, 7.06
40 CFR 60, D
40 CFR 64,
40 CFR 72-73,
40 CFR 75-78,
40 CFR 63, UUUUU</td><td>C10, C11[a], C23</td><td>S4[a]</td></tr>
<tr><td>C10, C23, C30, C31[b]</td><td>S34[b]</td></tr>
<tr><td>E8</td><td>Five (5) coal silos, make American Air Filter, controlled by a centrifugal dust collector and equipped with five (5) coal mills, make Babcock & Wilcox.</td><td>5.00, 5.01, 5.20, 5.21, 5.22, 5.23, 6.09</td><td>C12</td><td>S8</td></tr>
</table>

[67] This unit was modified under construction permit 216-01 (SCR), 225-01 (Ammonia tanks), and 34595-12-C.

Emission Point	Description	Applicable Regulation	Control ID	Stack ID
Note a: The existing FGD (C11, S4) will shut down before April 16, 2016, the compliance date when this unit has to comply with 40 CFR 63, Subpart UUUUU. Note b: The new FGD, HAP PM control and stack (C30, C31, and S34) will replace C11 and S4. These new control devices need to be in full operation no later than April 16, 2016, the compliance date when this unit has to comply with 40 CFR 63, Subpart UUUUU.[68]				

U4 Control Devices:

Before compliance with 40 CFR 63, Subpart UUUUU, Unit 4 uses the following control devices:

ID	Description	Performance Indicator	Stack ID
C10	One (1) custom-built electrostatic precipitator (ESP) for PM control, make Western Precipitator Division	PM emission data from PM CEMS (if PM CEMS is not used to demonstrate compliance)	S4
C11	One (1) Flue Gas Desulfurization (FGD) unit for SO_2 control using limestone scrubbing liquor, make Combustion Engineering	N/A[69]	
C12	One (1) centrifugal dust collector, make American Air Filter	N/A[70]	S8
C23	One (1) Selective Catalytic Reduction (SCR), make Babcock Borsig Power, and the associated ammonia storage tanks. [71]	N/A[69]	S4

After compliance with 40 CFR 63, Subpart UUUUU, Unit 4 uses the following control devices:

ID	Description	Performance Indicator	Stack ID
C10	One (1) custom-built electrostatic precipitator (ESP) for PM control, make Western Precipitator Division	N/A[69]	S34

[68] On December 31, 2014, LG&E submitted a notification for initial startup of PJFF (C30) and FGD (C31) for U4. These control devices went into service on December 19, 2014.

[69] This unit is equipped with CEMS for NOx, SO2, and PM. According to the District's letter dated November 1, 2005, parametric monitoring of the ESP, FGD, and PJFF for this unit is removed as such monitoring would no longer be required for demonstration of compliance. On July 22, 2016, LG&E reported the normal pressure drop range for U4 PJFF, 2 – 6 inches of water, established during 90 consecutive operating days.

[70] For the coal silos (E8), the owner or operator has shown, by worst-case calculations without allowance for a control device, that the hourly uncontrolled PM emission standard cannot be exceeded; therefore, no additional monitoring, recordkeeping, or reporting is required to demonstrate compliance with the applicable PM standards specified in Regulation 6.09 and 7.08 is required for this emission point.

[71] The two ammonia storage tanks are housed in a roof-covered building which has secondary containment for about 66,000 gallons of liquid ammonia (110% of one tank) if a release occurs. The ammonia, under pressure, will be a liquid but will convert to a gas after it is released. The building and tanks contain alarms and leak detection devices. Ammonia from either tank can be used by either Unit 3 or Unit 4 SCR System.

ID	Description	Performance Indicator	Stack ID
C12	One (1) centrifugal dust collector, make American Air Filter	N/A[70]	S8
C23	One (1) Selective Catalytic Reduction (SCR), make Babcock Borsig Power	N/A[69]	S34
C30	One (1) HAP particulate matter control system, consists of: one (1) powdered activated carbon (PAC) injection system; one (1) dry sorbent injection system; liquid additive system(s); and one (1) pulse-jet fabric filter (PJFF) baghouse used for collecting PM from the boiler and PAC and dry sorbent injection system. PJFF make Clyde Bergemann Power Group, model Structural Pulse Jet	PM Control: PM emission data from PM CEMS (if PM CEMS is not used to demonstrate compliance) Hg control: (1) Minimum PAC injection rate;[72] (2) pH of reactant in FGD, 4.8-6.4; (3) Hg emission data from Sorbent Traps	S34
C31	One (1) Flue Gas Desulfurization (FGD) unit for SO_2 control using limestone scrubbing liquor, make Babcock Power Environmental	N/A[69]	S34

[72] In a letter dated October 4, 2016, LG&E demonstrated that in certain circumstance EGUs at this plant can meet the MACT mercury standard at zero PAC injection rate. Therefore the source is allowed to use flexible mercury control measures, including PAC injection or liquid additive system, to achieve compliance with MACT mercury standard.

U4 Specific Conditions

S1. **Standards**[73] (Regulation 2.16, section 4.1.1)

a. **NO_x**

i. The owner or operator shall not allow the average NO_x emissions to exceed the alternate contemporaneous emission limitation of 0.46 lb/MMBtu of heat input on an <u>annual</u> average basis, as specified in Acid Rain Permit No.176-97-AR (R4). (See Acid Rain Permit Attachment) (Regulation 6.47, section 3.5 referencing 40 CFR Part 76)

ii. The owner or operator shall not exceed the NO_x RACT emissions standard of 0.52 lb/MMBtu of heat input based on a rolling <u>30-day</u> average. (See NO_x RACT Attachment) (Regulation 6.42, section 4.3)

iii. When combusting natural gas, the owner or operator shall not cause to be discharged into the atmosphere any gases which contain nitrogen oxides expressed as nitrogen dioxide in excess of 86 ng/J (0.20 lb/MMBtu) heat input on a <u>3-hour</u> rolling average. (Regulation 7.06, section 6.1.1) (40 CFR 60.44(a)(1))

iv. When combusting coal, the owner or operator shall not cause to be discharged into the atmosphere any gases which contain nitrogen oxides expressed as nitrogen dioxide in excess of 300 ng/J (0.70 lb/MMBtu) heat input on a <u>3-hour</u> rolling average. (Regulation 7.06, section 6.1.3) (40 CFR 60.44(a)(3))

v. When natural gas and coal are burned simultaneously in any combination, the applicable standard is determined by proration using the following equation: (40 CFR 60.44(b))

$$PS_{NOx} = \frac{x(86) + z(300)}{(x + z)}$$

Where,

PS_{NOx} = Prorates standard for NOx when burning different fuels simultaneously, in ng/J heat input derived from all fossil fuels fired;
x = Percentage of total heat input from gaseous fossil fuel
z = Percentage of total heat from solid fossil fuel (except lignite)

vi. The owner or operator shall install, maintain, calibrate and operate a continuous emission monitoring system (CEMS) for the measurement or calculation of nitrogen oxides in the flue gas. (Regulation 6.02, section

[73] The emission standards, monitoring, record keeping, and reporting requirements only apply to the boiler E7 (not the coal silos E8) if not indicated.

6.1.3) (NO_x RACT Plan) (Regulation 6.47, section 3.4 referencing 40 CFR 75.10(a)(2))

b. **SO_2**

i. The owner or operator shall not exceed 0.8 lb/MMBtu heat input for combustion of natural gas and 1.2 lb/MMBtu heat input for combustion of coal based on a three hour rolling average. (Regulation 7.06, section 5.1.2) (40 CFR 60.43(a)(2)))

ii. When natural gas and coal fuels are burned simultaneously in any combination, the applicable standard is determined by proration using the following equation: (Regulation 2.16, section 4.1.1)

$$PS_{SO2} = \frac{x(0.8) + z(1.2)}{(x + z)}$$

Where,

PS_{SO2} = Prorates standard for SO_2 when burning different fuels simultaneously, in lb/MMBtu heat input derived from all fossil fuels fired;
x = Percentage of total heat input from gaseous fossil fuel
z = Percentage of total heat from solid fossil fuel (except lignite)

iii. Compliance shall be based on the total heat input from all fossil fuels burned, including gaseous fuels. (40 CFR 60.43(c))

iv. The owner or operator shall comply with the annual SO_2 emission allowances as specified in Acid Rain Permit No.176-97-AR (R4). (See Acid Rain Permit Attachment) (Regulation 6.47, section 3.2 referencing 40 CFR Part 73)

v. The owner or operator shall operate and maintain the FGD, as recommended by the manufacturer, at all times the respective boiler is in operation, including periods of startup, shutdown, and malfunction, in a manner consistent with good air pollution control practice to meet the standards.[74] (Regulation 2.16, section 4.1.1)

vi. The owner or operator shall install, maintain, calibrate and operate a continuous emission monitoring system (CEMS) for the measurement of sulfur dioxide in the flue gas. (Regulation 6.02, section 6.1.2) (Regulation 6.47, section 3.4 referencing 40 CFR 75.10(a)(1))

[74] The SO2 emissions cannot meet the standards uncontrolled. The owner or operator is required to operate the control devices to meet the applicable limits for SO2.

c. **PM**

i. The owner or operator shall not exceed an allowable particulate emission rate of 0.10 lbs/MMBtu heat input based on a three hour rolling average. (Regulation 7.06, section 4.1.2)

ii. The owner or operator shall not cause to be discharged into the atmosphere from any affected facility any gases that contain PM in excess of 43 ng/J heat input (0.10 lb/MMBtu) derived from fossil fuel. (40 CFR 60.42(a)(1))

iii. The owner or operator shall operate and maintain the PM control devices, as recommended by the manufacturer, at all times the respective boiler is in operation, including periods of startup, shutdown, and malfunction, in a manner consistent with good air pollution control practice to meet the standards. Following commissioning of the PJFF baghouses, the owner or operator may elect to operate, turn down, or turn off the ESP to ensure the efficient operation of the PJFF baghouse.[75] (Regulation 2.16, section 4.1.1)

iv. The company shall follow one of the two options below to demonstrate compliance with PM standards:

Compliance Options	PM	Opacity	Control Device Performance indication
Option 1	Certified PM CEMS	VE/Method 9, or Certified COMS	N/A
Option 2	Annual testing	Certified COMS	PM CEMS

v. For the coal silos (E8), the owner or operator shall not exceed an allowable particulate emission rate of 82.95 lbs/hr from five coal silos combined based on actual operating hours in a calendar day.[76] (Regulation 6.09, section 3.2)

d. **Opacity**

i. The owner or operator shall not cause the emission into the open air of particulate matter from any indirect heat exchanger which is greater than 20% opacity, except for emissions from an indirect heat exchanger during building a new fire for the period required to bring the boiler up to operating conditions provided the method used is that recommended by the

[75] The PM emissions cannot meet the standards uncontrolled. The owner or operator is required to operate the control devices to meet the applicable limits for PM.

[76] For the coal silos (E8), the owner or operator has shown, by worst-case calculations without allowance for a control device, that the hourly uncontrolled PM emission standard cannot be exceeded; therefore, no additional monitoring, recordkeeping, or reporting is required to demonstrate compliance with the applicable PM standards specified in Regulation 6.09 and 7.08 is required for this emission point.

manufacturer and the time does not exceed the manufacturer's recommendations. (Regulation 7.06, section 4.2)

ii. The company shall follow one of the two options in the table under Specific Condition S1.c.iv to demonstrate compliance with opacity standards.

iii. The owner or operator shall not cause the emission into the open air of particulate matter that exhibit greater than 20% opacity except for one six-minute period per hour of not more that 27%. (40 CFR 60.42(a)(2))

iv. For the coal silos (E8), the owner or operator shall not allow visible emissions to equal or exceed 20% opacity. (Regulation 6.09, section 3.1) (Regulation 7.08, section 3.1.1)

e. **TAC**

i. The owner or operator shall not allow TAC emissions from boiler E7 to exceed the TAC emission standards determined based upon the EA Demonstration provided to the District.[77] (Regulation 5.21, section 4.2 and section 4.3) (See Comment 1)

TAC Name	CAS #	TAC Limits Determination (lbs/yr)	Basis of Limits
Naphthalene	91-20-3	27.0	Controlled PTE
Chloroform	67-66-3	24.2	Controlled PTE
Formaldehyde	50-00-0	114.4	Controlled PTE
Hydrogen fluoride	7664-39-3	21,802	Controlled PTE
Arsenic compounds	7440-38-2	434	Controlled PTE
Cadmium compounds	7440-43-9	68.6	Controlled PTE
Chromium VI	7440-47-3	153.9	Controlled PTE
Chromium III	16065-83-1	353	Controlled PTE
Cobalt compounds	7440-48-4	91.5	Controlled PTE
Lead compounds	7439-92-1	541	Controlled PTE
Manganese compounds	7439-96-5	691	Controlled PTE
Nickel compounds	7440-02-0	499	Controlled PTE
Sulfuric acid	7664-93-9	193,310	Controlled PTE
Benzene	71-43-2	De minimis values (See Comment 1)	De Minimis
Bromoform	75-25-2		De Minimis
Methylene chloride	75-09-2		De Minimis
Tetrachloroethylene (Perc)	127-18-4		De Minimis
Toluene	108-88-3		De Minimis
Xylene	1330-20-7		De Minimis

[77] This table for TAC emission standards has been revised to exclude Category 3 and 4 TACs for existing sources and use "de minimis values", instead of actual numbers for current de minimis levels, as emission standards.

TAC Name	CAS #	TAC Limits Determination	
		(lbs/yr)	Basis of Limits
Hydrochloric acid	7647-01-0		De Minimis

ii. See Plantwide Requirements S1.b.

f. **HAP** (40 CFR 63, Subpart UUUUU)

The owner or operator shall comply with 40 CFR 63, Subpart UUUUU (See Attachment A) no later than April 16, 2016.[78]

g. **112(r) Regulated Substances (Regulation 5.15)**

If anhydrous ammonia is present at the stationary source in an amount greater than the threshold quantity specified in Regulation 5.15, the owner or operator shall comply with the requirements specified in Regulation 5.15, including the requirement to submit a Risk Management Plan in a method and format as specified by the District and EPA.[79] (Construction Permit 225-01-C)

h. **BART** (40 CFR 52, Subpart S)

i. The owner or operator shall install sorbent injection to control SO_3 emissions and continue to utilize PJFF baghouse and/or existing ESP to control PM emissions for this unit.[80] (40 CFR 52.920(e) refer to Kentucky Regional Haze SIP)

ii. The owner or operator shall not allow H_2SO_4 emissions from this unit to exceed 76.5 lbs/hr based on actual operating houses in a calendar day. (40 CFR 52.920(e) refer to Kentucky Regional Haze SIP)

S2. **Monitoring and Record Keeping** (Regulation 2.16, sections 4.1.9.1 and 4.1.9.2)

The owner or operator shall maintain the following records for a minimum of 5 years and make the records readily available to the District upon request.

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[78] According to 40 CFR 63.9984(b), the compliance date for an existing EGU is April 16, 2015. LG&E requested a year extension and the District has approved the request for the extension per (40 CFR 63.6(i)(4)(i)). Therefore the compliance date for the EGUs under this construction is April 16, 2016.

[79] The two ammonia storage tanks are housed in a roof-covered building which has secondary containment for about 66,000 gallons of liquid ammonia (110% of one tank) if a release occurs. The ammonia, under pressure, will be a liquid but will convert to a gas after it is released. The building and tanks contain alarms and leak detection devices. Ammonia from either tank can be used by either Unit 3 or Unit 4 SCR System.

[80] On March 30, 2012, EPA finalized a limited approval and a limited disapproval of the Kentucky state implementation plan submitted on June 25, 2008 and May 28, 2010. According to 40 CFR 52.920(e), the owner or operator shall meet BART requirements summarized in Table 7.5.3-2 of the Commonwealth's May 28, 2010 submittal. A sorbent injection system has been installed for this unit in 2015.

a. **NO_x**

i. The owner or operator shall demonstrate compliance with NO_x RACT Plan limits by continuous emissions monitors (CEMs) as specified in the NO_x RACT Plan. (See NO_x RACT Attachment) (Regulation 6.42, section 4.3)

ii. The owner or operator shall keep a record identifying all deviations from the requirements of the NO_x RACT Plan.

iii. The owner or operator shall comply with the NO_x compliance plan requirements specified in the attached Acid Rain Permit, No.176-97-AR (R4). These record keeping requirements shall be determined in accordance with the Title IV Phase II Acid Rain Permit and are specified in 40 CFR Part 75 Subpart F. (See Appendix A to NOx RACT Plan) (Regulation 6.47, section 3.4 and 3.5 referencing 40 CFR Parts 75 and 76)

iv. The owner or operator shall record on an hourly basis all NO_x emission data specified in 40 CFR Part 75, section 75.57(d). For each NO_x emission rate (in lb/mmBtu) measured by a NO_x-diluent monitoring system, or, if applicable, for each NO_x concentration (in ppm) measured by a NO_x concentration monitoring system used to calculate NO_x mass emissions under 40 CFR 75.71(a)(2), record the following data as measured and reported from the certified primary monitor, certified back-up monitor, or other approved method of emissions determination:

1) Component-system identification code, as provided in 40 CFR 75.53 (including identification code for the moisture monitoring system, if applicable); (40 CFR 75.57(d)(1))

2) Date and hour; (40 CFR 75.57(d)(2))

3) Hourly average NO_x concentration (ppm, rounded to the nearest tenth) and hourly average NO_x concentration (ppm, rounded to the nearest tenth) adjusted for bias if bias adjustment factor required, as provided in 40 CFR 75.24(d); (40 CFR 75.57(d)(3))

4) Hourly average diluent gas concentration (for NO_x -diluent monitoring systems, only, in units of percent O_2 or percent CO_2, rounded to the nearest tenth); (40 CFR 75.57(d)(4))

5) If applicable, the hourly average moisture content of the stack gas (percent H_2O, rounded to the nearest tenth). If the continuous moisture monitoring system consists of wet- and dry-basis oxygen analyzers, also record both the hourly wet- and dry-basis oxygen readings (in percent O2, rounded to the nearest tenth); (40 CFR 75.57(d)(5))

6) Hourly average NO_x emission rate (for NO_x -diluent monitoring systems only, in units of lb/mmBtu, rounded to the nearest thousandth); (40 CFR 75.57(d)(6))

7) Hourly average NO_x emission rate (for NO_x -diluent monitoring systems only, in units of lb/mmBtu, rounded to the nearest thousandth), adjusted for bias if bias adjustment factor is required, as provided in 40 CFR 75.24(d). The requirement to report hourly NO_x emission rates to the nearest thousandth shall not affect NO_x compliance determinations under part 76 of this chapter; compliance with each applicable emission limit under part 76 shall be determined to the nearest hundredth pound per million Btu; (40 CFR 75.57(d)(7))

8) Percent monitoring system data availability (recorded to the nearest tenth of a percent), for the NO_x -diluent or NO_x concentration monitoring system, and, if applicable, for the moisture monitoring system, calculated pursuant to 40 CFR 75.32; (40 CFR 75.57(d)(8))

9) Method of determination for hourly average NO_x emission rate or NO_x concentration and (if applicable) for the hourly average moisture percentage, using Codes 1–55 in Table 4a of 40 CFR 75.57; and (40 CFR 75.57(d)(9))

10) Identification codes for emissions formulas used to derive hourly average NO_x emission rate and total NO_x mass emissions, as provided in 40 CFR 75.53, and (if applicable) the F-factor used to convert NO_x concentrations into emission rates. (40 CFR 75.57(d)(10))

v. A CEMS for measuring either oxygen (O_2) or carbon dioxide (CO_2) in the flue gases shall be installed, calibrated, maintained, and operated by the owner or operator. The owner or operator shall use the conversion procedures specified in Regulation 7.06, sections 7.5 and 7.6 for NO_x, SO_2, and PM. (Regulation 7.06, section 7.4)

vi. The owner or operator shall monitor the NO_x emissions, the NO_x allowances, as specified in the Clean Air Interstate Rule or the applicable NOx cap and trade program(s) in effect.

vii. For performance evaluations under 40 CFR 60.13(c) and calibration checks under 40 CFR 60.13(d), the procedures required in 40 CFR 60.45(c) (See U3 Specific Condition S2.a.vii) shall be used.

viii. The conversion procedures in 40 CFR 60.45(e) and (f) shall be used to convert the continuous monitoring data into units of the applicable standards. See U3 Specific Condition S2.a.viii. (40 CFR 60.45(e) and (f))

b. **SO_2**

i. The owner or operator shall maintain hourly records of SO_2 emissions as specified in Regulation 6.02, section 6.1.2.

ii. The owner or operator shall record on an hourly basis all SO_2 emission data specified in 40 CFR 75.57(c):

1) For SO_2 concentration during unit operation, as measured and reported from each certified primary monitor, certified back-up monitor, or other approved method of emissions determination: (40 CFR 75.57(c)(1))

(a) Component-system identification code, as provided in 40 CFR 75.53; (40 CFR 75.57(c)(1)(i))

(b) Date and hour; (40 CFR 75.57(c)(1)(ii))

(c) Hourly average SO_2 concentration (ppm, rounded to the nearest tenth); (40 CFR 75.57(c)(1)(iii))

(d) Hourly average SO_2 concentration (ppm, rounded to the nearest tenth), adjusted for bias if bias adjustment factor is required, as provided in 40 CFR 75.24(d); (40 CFR 75.57(c)(1)(iv))

(e) Percent monitor data availability (recorded to the nearest tenth of a percent), calculated pursuant to 40 CFR 75.32; and (40 CFR 75.57(c)(1)(v))

(f) Method of determination for hourly average SO_2 concentration using Codes 1–55 in Table 4a of 40 CFR 75.57. (40 CFR 75.57(c)(1)(vi))

2) For flow rate during unit operation, as measured and reported from each certified primary monitor, certified back-up monitor, or other approved method of emissions determination: (40 CFR 75.57(c)(2))

(a) Component-system identification code, as provided in 40 CFR 75.53; (40 CFR 75.57(c)(2)(i))

(b) Date and hour; (40 CFR 75.57(c)(2)(ii))

(c) Hourly average volumetric flow rate (in scfh, rounded to the nearest thousand); (40 CFR 75.57(c)(2)(iii))

(d) Hourly average volumetric flow rate (in scfh, rounded to the nearest thousand), adjusted for bias if bias adjustment factor required, as provided in 40 CFR 75.24(d); (40 CFR 75.57(c)(2)(iv))

(e) Percent monitor data availability (recorded to the nearest tenth of a percent) for the flow monitor, calculated pursuant to 40 CFR 75.32; and (40 CFR 75.57(c)(2)(v))

(f) Method of determination for hourly average flow rate using Codes 1–55 in Table 4a of 40 CFR 75.57. (40 CFR 75.57(c)(2)(vi))

3) For SO_2 mass emission rate during unit operation, as measured and reported from the certified primary monitoring system(s), certified redundant or non-redundant back-up monitoring system(s), or other approved method(s) of emissions determination: (40 CFR 75.57(c)(4))

(a) Date and hour; (40 CFR 75.57(c)(4)(i))

(b) Hourly SO_2 mass emission rate (lb/hr, rounded to the nearest tenth); (40 CFR 75.57(c)(4)(ii))

(c) Hourly SO_2 mass emission rate (lb/hr, rounded to the nearest tenth), adjusted for bias if bias adjustment factor required, as provided in 40 CFR 75.24(d); and (40 CFR 75.57(c)(4)(iii))

(d) Identification code for emissions formula used to derive hourly SO2 mass emission rate from SO2 concentration and flow and (if applicable) moisture data in paragraphs (c)(1), (c)(2), and (c)(3) of 40 CFR 75.57, as provided in 40 CFR 75.53. (40 CFR 75.57(c)(4)(iv))

iii. For performance evaluations under 40 CFR 60.13(c) and calibration checks under 40 CFR 60.13(d), the following procedures shall be used: (40 CFR 60.45(c))

1) Methods 6, 7, and 3B of appendix A of this part, as applicable, shall be used for the performance evaluations of SO_2 and NO_X continuous monitoring systems. Acceptable alternative methods for Methods 6,

7, and 3B of appendix A of this part are given in 40 CFR 60.46(d). (40 CFR 60.45(c)(1))

2) Sulfur dioxide or nitric oxide, as applicable, shall be used for preparing calibration gas mixtures under Performance Specification 2 of appendix B to this part. (40 CFR 60.45(c)(2))

3) For affected facilities burning fossil fuel(s), the span value for a continuous monitoring system measuring the opacity of emissions shall be 80, 90, or 100 percent. For a continuous monitoring system measuring sulfur oxides or NO_X the span value shall be determined using one of the following procedures: (40 CFR 60.45(c)(3))

(a) Except as provided under paragraph 40 CFR 60.45(c)(3)(ii), SO_2 and NO_X span values shall be determined as follows: (40 CFR 60.45(c)(3)(i))

Fossil fuel	In parts per million	
	Span value for SO_2	Span value for NO_X
Gas	Not Applicable	500.
Liquid	1,000	500.
Solid	1,500	1,000.

(b) As an alternative to meeting the requirements of paragraph 40 CFR 60.45(c)(3)(i), the owner or operator of an affected facility may elect to use the SO_2 and NO_X span values determined according to sections 2.1.1 and 2.1.2 in appendix A to part 75 of this chapter. (40 CFR 60.45(c)(3)(ii))

iv. The conversion procedures in 40 CFR 60.45(e) and (f) shall be used to convert the continuous monitoring data into units of the applicable standards. (40 CFR 60.45(e) and (f))

1) For any CEMS installed under paragraph (a) of this section, the following conversion procedures shall be used to convert the continuous monitoring data into units of the applicable standards (ng/J, lb/MMBtu): (40 CFR 60.45(e))

(a) When a CEMS for measuring O_2 is selected, the measurement of the pollutant concentration and O_2 concentration shall each be on a consistent basis (wet or dry). Alternative procedures approved by the Administrator shall be used when measurements are on a wet basis. When measurements are on a dry basis, the following conversion procedure shall be used: (40 CFR 60.45(e)(1))

$$E = CF\left(\frac{20.9}{(20.9 - \%O_2)}\right)$$

Where E, C, F, and $\%O_2$ are determined under paragraph (f) of this section.

(b) When a CEMS for measuring CO_2 is selected, the measurement of the pollutant concentration and CO_2 concentration shall each be on a consistent basis (wet or dry) and the following conversion procedure shall be used: (40 CFR 60.45(e)(2))

$$E = CF_c\left(\frac{100}{\%CO_2}\right)$$

Where E, C, F_c and $\%CO_2$ are determined under paragraph (f) of this section.

2) The values used in the equations under paragraphs (e)(1) and (2) of this section are derived as follows: (40 CFR 60.45(f))

(a) E = pollutant emissions, ng/J (lb/MMBtu). (40 CFR 60.45(f)(1))

(b) C = pollutant concentration, ng/dscm (lb/dscf), determined by multiplying the average concentration (ppm) for each one-hour period by 4.15×10^{4} M ng/dscm per ppm (2.59×10^{-9}M lb/dscf per ppm) where M = pollutant molecular weight, g/g-mole (lb/lb-mole). M = 64.07 for SO_2 and 46.01 for NO_X. (40 CFR 60.45(f)(2))

(c) $\%O_2$, $\%CO_2$= O_2 or CO_2 volume (expressed as percent), determined with equipment specified under paragraph (a) of this section. (40 CFR 60.45(f)(3))

(d) F, F_c= a factor representing a ratio of the volume of dry flue gases generated to the calorific value of the fuel combusted (F), and a factor representing a ratio of the volume of CO_2 generated to the calorific value of the fuel combusted (F_c), respectively. Values of F and F_c are given as follows: (40 CFR 60.45(f)(4))

(i) For anthracite coal as classified according to ASTM D388 (incorporated by reference, see 40 CFR 60.17), F = $2{,}723 \times 10^{-17}$ dscm/J (10,140 dscf/MMBtu) and F_c= 0.532×10^{-17} scm CO_2/J (1,980 scf

CO_2/MMBtu). (40 CFR 60.45(f)(4)(i))

(ii) For subbituminous and bituminous coal as classified according to ASTM D388 (incorporated by reference, see 40 CFR 60.17), $F = 2.637 \times 10^{-7}$ dscm/J (9,820 dscf/MMBtu) and $F_c = 0.486 \times 10^{-7}$ scm CO_2/J (1,810 scf CO_2/MMBtu). (40 CFR 60.45(f)(4)(ii))

(iii) For liquid fossil fuels including crude, residual, and distillate oils, $F = 2.476 \times 10^{-7}$ dscm/J (9,220 dscf/MMBtu) and $F_c = 0.384 \times 10^{-7}$ scm CO_2/J (1,430 scf CO_2/MMBtu). (40 CFR 60.45(f)(4)(iii))

(iv) For gaseous fossil fuels, $F = 2.347 \times 10^{-7}$ dscm/J (8,740 dscf/MMBtu). For natural gas, propane, and butane fuels, $F_c = 0.279 \times 10^{-7}$ scm CO_2/J (1,040 scf CO_2/MMBtu) for natural gas, 0.322×10^{-7} scm CO_2/J (1,200 scf CO_2/MMBtu) for propane, and 0.338×10^{-7} scm CO_2/J (1,260 scf CO_2/MMBtu) for butane. (40 CFR 60.45(f)(4)(iv))

(v) For bark $F = 2.589 \times 10^{-7}$ dscm/J (9,640 dscf/MMBtu) and $F_c = 0.500 \times 10^{-7}$ scm CO_2/J (1,840 scf CO_2/MMBtu). For wood residue other than bark $F = 2.492 \times 10^{-7}$ dscm/J (9,280 dscf/MMBtu) and $F_c = 0.494 \times 10^{-7}$ scm CO_2/J (1,860 scf CO_2/MMBtu). (40 CFR 60.45(f)(4)(v))

(vi) For lignite coal as classified according to ASTM D388 (incorporated by reference, see 40 CFR 60.17), $F = 2.659 \times 10^{-7}$ dscm/J (9,900 dscf/MMBtu) and $F_c = 0.516 \times 10^{-7}$ scm CO_2/J (1,920 scf CO_2/MMBtu). (40 CFR 60.45(f)(4)(vi))

(e) The owner or operator may use the following equation to determine an F factor (dscm/J or dscf/MMBtu) on a dry basis (if it is desired to calculate F on a wet basis, consult the Administrator) or Fc factor (scm CO_2/J, or scf CO_2/MMBtu) on either basis in lieu of the F or F_c factors specified in paragraph (f)(4) of this section: (40 CFR 60.45(f)(5))

$$F = 10^{-6} \frac{[227.2\ (\%H) + 95.5\ (\%C) + 35.6\ (\%S) + 8.7\ (\%N) - 28.7\ (\%O)]}{GCV}$$

$$F_c = \frac{2.0 \times 10^{-5}\ (\%C)}{GCV\ (SI\ units)}$$

$$F = 10^{-6} \frac{[3.64\ (\%H) + 1.53\ (\%C) + 0.57\ (\%S) + 0.14\ (\%N) - 0.46\ (\%O)]}{GCV\ (English\ units)}$$

$$F_c = \frac{20.0\ (\%C)}{GCV\ (SI\ units)}$$

$$F_c = \frac{321 \times 10^3\ (\%C)}{GCV\ (English\ units)}$$

(i) %H, %C, %S, %N, and %O are content by weight of hydrogen, carbon, sulfur, nitrogen, and O_2(expressed as percent), respectively, as determined on the same basis as GCV by ultimate analysis of the fuel fired, using ASTM D3178 or D3176 (solid fuels), or computed from results using ASTM D1137, D1945, or D1946 (gaseous fuels) as applicable. (These five methods are incorporated by reference, see 40 CFR 60.17.) (40 CFR 60.45(f)(5)(i))

(ii) GVC is the gross calorific value (kJ/kg, Btu/lb) of the fuel combusted determined by the ASTM test methods D2015 or D5865 for solid fuels and D1826 for gaseous fuels as applicable. (These three methods are incorporated by reference, see 40 CFR 60.17.) (40 CFR 60.45(f)(5)(ii))

(iii) For affected facilities which fire both fossil fuels and nonfossil fuels, the F or Fc value shall be subject to the Administrator's approval. (40 CFR 60.45(f)(5)(iii))

(f) For affected facilities firing combinations of fossil fuels or fossil fuels and wood residue, the F or Fc factors determined by paragraphs (f)(4) or (f)(5) of this section shall be prorated in accordance with the applicable formula as follows: (40 CFR 60.45(f)(6))

$$F = \sum_{i=1}^{n} X_i F_i \quad \text{or} \quad F_c = \sum_{i=1}^{n} X_i \left(F_c\right)_i$$

Where:
X_i= Fraction of total heat input derived from each type of fuel (e.g. natural gas, bituminous coal, wood residue, etc.);
F_i or $(F_c)_i$= Applicable F or F_c factor for each fuel type determined in accordance with paragraphs (f)(4) and (f)(5) of this section; and
n = Number of fuels being burned in combination.

c. **PM**

i. The company shall follow one of the two options below to demonstrate compliance with PM standards:

1) Option 1: the owner or operator shall install, maintain, calibrate, and operate a PM CEMS for each steam generating unit.[81],[82] (Regulation 2.16, section 4.1.1) (See Comment 2) (40 CFR 64)

(a) The use of PM CEMS as the measurement technique must be appropriate for the stack conditions.

(b) The PM CEMS must be installed, operated and maintained in accordance with the manufacturer's recommendations, applicable requirements in Subpart D, and General Provisions in 40 CFR 60.7 – 60.13.

(c) The PM CEMS must be certified in accordance with Performance Specification 11, Specifications and Test Procedures for Particulate Matter Continuous Emission Monitoring Systems at Stationary Sources, found in 40 CFR 60, Appendix B.

(d) A quality assurance/quality control program must be implemented in accordance with procedures in 40 CFR 60, Appendix F, Procedure 2 (Quality Assurance Requirements

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[81] According to LG&E's request, PM CEMS have been installed, calibrated, maintained, and operated for Unit 1. LG&E requested permission to remove COMS for Unit 3 and 4 under provisions in 40 CFR 60.13(i)(1), "Alternative monitoring requirements when installation of a continuous monitoring system or monitoring device specified by this part would not provide accurate measurements due to liquid water or other interferences caused by substances in the effluent gases." LG&E's proposal for Unit 3 and 4 was accepted in a letter from EPA dated Feb. 28, 2007. The District accordingly approved LG&E's request for removing COMS for Unit 1 and 2 providing PM CEMS are appropriately installed for these units.

[82] The coal-fired boilers are subject to 40 CFR Part 64 - Compliance Assurance Monitoring (CAM) for Major Stationary Source since SO2, PM, and NOx emissions from each of the boilers may be greater than the major source threshold and control devices are required to achieve compliance with standards. On 5/21/2014, LG&E submitted a revised CAM Plan in which SO2 and NOx CEMS are used for compliance demonstration. PM CEMS is used to demonstrate compliance or provide an indication of continuous PM control.

for Particulate Matter Continuous Emission Monitoring Systems at Stationary Sources).

(e) Compliance with the particulate matter emission limit promulgated at 40 CFR 60.42(a) will be based upon three-hour rolling average periods during source operation.

(f) LG&E must comply with all applicable recordkeeping and reporting requirements under Subpart D and under the General Provisions in 40 CFR 60.7 – 60.13. Quarterly excess emission reports must be submitted, and PM excess emissions shall be reported based upon three-hour rolling averages during source operation.

2) Option 2: the owner or operator shall conduct an annual EPA Reference Method 5 performance test following the testing requirements in Attachment B, Specific Condition b.ii.

ii. If certified PM CEMS (Option 1) is used to demonstrate compliance with PM standards, the owner or operator shall record on an hourly basis all PM emission data, in lb/MMBtu, from PM CEMS.[83] (40 CFR 64)

iii. If annual PM testing (Option 2) is used to demonstrate compliance with PM standards, the owner or operator shall use PM CEMS as a performance indicator of continuous normal operation of the PM control devices and do the following:[83] (40 CFR 64)

1) The owner or operator shall monitor and record all PM emission data from PM CEMS, which is used as the indicator of normal operation of the PM control devices.

2) The owner or operator shall maintain daily records of any periods of time where the process was operating and the PM control devices were not operating or a declaration that the PM control devices operated at all times that day when the process was operating.

3) If there is any time that the PM control devices are bypassed or not in operation when the process is operating, then the owner or operator shall keep a record of the following for each bypass event:

(a) Date;

[83] The coal-fired boilers are subject to 40 CFR Part 64 - Compliance Assurance Monitoring (CAM) for Major Stationary Source since SO2, PM, and NOx emissions from each of the boilers may be greater than the major source threshold and control devices are required to achieve compliance with standards. On 5/21/2014, LG&E submitted a revised CAM Plan in which SO2 and NOx CEMS are used for compliance demonstration. PM CEMS is used to demonstrate compliance or provide an indication of continuous PM control.

(b) Start time and stop time;
(c) Identification of the control devices and process equipment;
(d) PM emissions during the bypass in lb/hr;
(e) Summary of the cause or reason for each bypass event;
(f) Corrective action taken to minimize the extent or duration of the bypass event; and
(g) Measures implemented to prevent reoccurrence of the situation that resulted in the bypass event.

d. **Opacity**

i. If certified COMS is used to demonstrate compliance with opacity standards, the owner or operator shall record on an hourly basis all opacity from COMS.[84]

ii. If VE/Method 9 is used to demonstrate compliance with opacity standards, in order for the owner or operator to use its VE observations to satisfy the opacity monitoring requirement, the following conditions must be met:[84] (EPA Letter, 2007)

1) On a weekly basis, the owner or operator shall attempt to perform VE observations in accordance with procedures in EPA Method 9.

2) On the weeks when it is possible to collect unit-specific VE data, at least one hour of Method 9 data shall be collected for each unit.

3) Records of the Method 9 readings shall be submitted with the quarterly excess emission reports for PM emissions.

iii. The owner or operator shall keep a record of every Method 9 test performed or the reason why it could not be performed that day.

iv. An owner or operator of an affected facility subject to an opacity standard under 40 CFR 60.42 that elects to not use a COMS because the affected facility burns only fuels as specified under paragraph (b)(1) of 40 CFR 60.45, monitors PM emissions as specified under paragraph (b)(5) of 40 CFR 60.45, or monitors CO emissions as specified under paragraph (b)(6) of 40 CFR 60.45, shall conduct a performance test using Method 9 of appendix A-4 of this part and the procedures in 40 CFR 60.11 to demonstrate compliance with the applicable limit in 40 CFR 60.42 by April

[84] According to LG&E's request, PM CEMS have been installed, calibrated, maintained, and operated for Unit 1. LG&E requested permission to remove COMS for Unit 3 and 4 under provisions in 40 CFR 60.13(i)(1), "Alternative monitoring requirements when installation of a continuous monitoring system or monitoring device specified by this part would not provide accurate measurements due to liquid water or other interferences caused by substances in the effluent gases." LG&E's proposal for Unit 3 and 4 was accepted in a letter from EPA dated Feb. 28, 2007. The District accordingly approved LG&E's request for removing COMS for Unit 1 and 2 providing PM CEMS are appropriately installed for these units.

29, 2011 or within 45 days after stopping use of an existing COMS, whichever is later, and shall comply with either paragraph (b)(7)(i), (b)(7)(ii), or (b)(7)(iii) of 40 CFR 60.45. The observation period for Method 9 of appendix A-4 of this part performance tests may be reduced from 3 hours to 60 minutes if all 6-minute averages are less than 10 percent and all individual 15-second observations are less than or equal to 20 percent during the initial 60 minutes of observation. The permitting authority may exempt owners or operators of affected facilities burning only natural gas from the opacity monitoring requirements. (40 CFR 60.45(b)(7))

1) Except as provided in paragraph (b)(7)(ii) or (b)(7)(iii) of 40 CFR 60.45, the owner or operator shall conduct subsequent Method 9 of appendix A–4 of this part performance tests using the procedures in paragraph (b)(7) of 40 CFR 60.45 according to the applicable schedule in paragraphs (b)(7)(i)(A) through (b)(7)(i)(D) of 40 CFR 60.45, as determined by the most recent Method 9 of appendix A–4 of this part performance test results.

   (a) If no visible emissions are observed, a subsequent Method 9 of appendix A–4 of this part performance test must be completed within 12 calendar months from the date that the most recent performance test was conducted; (40 CFR 60.45(b)(7)(i)(A))

   (b) If visible emissions are observed but the maximum 6-minute average opacity is less than or equal to 5 percent, a subsequent Method 9 of appendix A–4 of this part performance test must be completed within 6 calendar months from the date that the most recent performance test was conducted; (40 CFR 60.45(b)(7)(i)(B))

   (c) If the maximum 6-minute average opacity is greater than 5 percent but less than or equal to 10 percent, a subsequent Method 9 of appendix A–4 of this part performance test must be completed within 3 calendar months from the date that the most recent performance test was conducted; or (40 CFR 60.45(b)(7)(i)(C))

   (d) If the maximum 6-minute average opacity is greater than 10 percent, a subsequent Method 9 of appendix A-4 of this part performance test must be completed within 45 calendar days from the date that the most recent performance test was conducted. (40 CFR 60.45(b)(7)(i)(D))

2) If the maximum 6-minute opacity is less than 10 percent during the most recent Method 9 of appendix A–4 of this part performance test, the owner or operator may, as an alternative to performing

subsequent Method 9 of appendix A–4 of this part performance test, elect to perform subsequent monitoring using Method 22 of appendix A–7 of this part according to the procedures specified in paragraphs (b)(7)(ii)(A) and (B) of 40 CFR 60.45. (40 CFR 60.45(b)(7)(ii))

(a) The owner or operator shall conduct 10 minute observations (during normal operation) each operating day the affected facility fires fuel for which an opacity standard is applicable using Method 22 of appendix A-7 of this part and demonstrate that the sum of the occurrences of any visible emissions is not in excess of 5 percent of the observation period (i.e., 30 seconds per 10 minute period). If the sum of the occurrence of any visible emissions is greater than 30 seconds during the initial 10 minute observation, immediately conduct a 30 minute observation. If the sum of the occurrence of visible emissions is greater than 5 percent of the observation period (i.e., 90 seconds per 30 minute period), the owner or operator shall either document and adjust the operation of the facility and demonstrate within 24 hours that the sum of the occurrence of visible emissions is equal to or less than 5 percent during a 30 minute observation (i.e., 90 seconds) or conduct a new Method 9 of appendix A-4 of this part performance test using the procedures in paragraph (b)(7) of 40 CFR 60.45 within 45 calendar days according to the requirements in 40 CFR 60.46(b)(3). (40 CFR 60.45(b)(7)(ii)(A))

(b) If no visible emissions are observed for 30 operating days during which an opacity standard is applicable, observations can be reduced to once every 7 operating days during which an opacity standard is applicable. If any visible emissions are observed, daily observations shall be resumed. (40 CFR 60.45(b)(7)(ii)(B))

3) If the maximum 6-minute opacity is less than 10 percent during the most recent Method 9 of appendix A–4 of this part performance test, the owner or operator may, as an alternative to performing subsequent Method 9 of appendix A–4 performance tests, elect to perform subsequent monitoring using a digital opacity compliance system according to a site-specific monitoring plan approved by the Administrator. The observations shall be similar, but not necessarily identical, to the requirements in paragraph (b)(7)(ii) of 40 CFR 60.45. For reference purposes in preparing the monitoring plan, see OAQPS "Determination of Visible Emission Opacity from Stationary Sources Using Computer-Based Photographic Analysis

Systems." This document is available from the U.S. Environmental Protection Agency (U.S. EPA); Office of Air Quality and Planning Standards; Sector Policies and Programs Division; Measurement Policy Group (D243–02), Research Triangle Park, NC 27711. This document is also available on the Technology Transfer Network (TTN) under Emission Measurement Center Preliminary Methods. (40 CFR 60.45(b)(7)(iii)

v. The owner or operator of an affected facility subject to the opacity limits in 40 CFR 60.42 that elects to monitor emissions according to the requirements in 40 CFR 60.45(b)(7) shall maintain records according to the requirements specified in paragraphs (h)(1) through (3) of 40 CFR 60.45, as applicable to the visible emissions monitoring method used. (40 CFR 60.45(h))

1) For each performance test conducted using Method 9 of appendix A–4 of this part, the owner or operator shall keep the records including the information specified in paragraphs (h)(1)(i) through (iii) of 40 CFR 60.45. (40 CFR 60.45(h)(1))

(a) Dates and time intervals of all opacity observation periods; (40 CFR 60.45(h)(1)(i))

(b) Name, affiliation, and copy of current visible emission reading certification for each visible emission observer participating in the performance test; and (40 CFR 60.45(h)(1)(ii))

(c) Copies of all visible emission observer opacity field data sheets; (40 CFR 60.45(h)(1)(iii))

2) For each performance test conducted using Method 22 of appendix A–4 of this part, the owner or operator shall keep the records including the information specified in paragraphs (h)(2)(i) through (iv) of 40 CFR 60.45. (40 CFR 60.45(h)(2))

(a) Dates and time intervals of all visible emissions observation periods; (40 CFR 60.45(h)(2)(i))

(b) Name and affiliation for each visible emission observer participating in the performance test; (40 CFR 60.45(h)(2)(ii))

(c) Copies of all visible emission observer opacity field data sheets; and (40 CFR 60.45(h)(2)(iii))

(d) Documentation of any adjustments made and the time the adjustments were completed to the affected facility operation by the owner or operator to demonstrate compliance with the applicable monitoring requirements. (40 CFR 60.45(h)(2)(iv))

3) For each digital opacity compliance system, the owner or operator shall maintain records and submit reports according to the requirements specified in the site-specific monitoring plan approved by the Administrator. (40 CFR 60.45(h)(3))

vi. For coal silos (E8):

1) The owner or operator shall conduct a weekly one-minute visible emissions survey, during normal operation, of the PM Emission Points (stacks). For Emission Points without observed visible emissions during twelve consecutive operating weeks, the owner or operator may elect to conduct a monthly one-minute visible emission survey, during normal operation.

2) At Emission Points where visible emissions are observed, the owner or operator shall initiate corrective action within eight hours of the initial observation. If the visible emissions persist, the owner or operator shall perform or cause to be performed a Method 9 for stack emissions within 24 hours of the initial observation. If the opacity standard is exceeded, the owner or operator shall report the exceedance to the District, according to Regulation 1.07, and take all practicable steps to eliminate the exceedance.

3) The owner or operator shall maintain records, monthly, of the results of all visible emissions surveys and tests. Records of the results of any visible emissions survey shall include the date of the survey, the name of the person conducting the survey, whether or not visible emissions were observed, and what if any corrective action was performed. If an emission point is not being operated during a given month, then no visible emission survey needs to be performed and a negative declaration shall be entered in the record.

e. **TAC**

i. The owner or operator shall monthly calculate and record TAC emissions for this unit in order to demonstrate compliance with the TAC emission standards.

ii. See Plantwide Requirements S2.b.

f. **HAP** (40 CFR 63, Subpart UUUUU)

i. The owner or operator shall comply with 40 CFR 63, Subpart UUUUU (See Attachment A) no later than April 16, 2016.

ii. The owner or operator shall establish a site-specific minimum activated carbon injection rate for PAC injection system according to Attachment B, Specific Condition a.i. The owner or operator shall monitor and record the activated carbon injection rate during each operating day. [85]

iii. The owner or operator shall monitor and record all Hg emission data from the Hg sorbent traps, which is used as the indicator of normal operation of the Hg control measures.

iv. The owner or operator shall monitor and record the pH of the reactant material in the FGD and any other parameters verified as having a direct effect on Hg emissions during each operating day, which is (are) used as the indicator(s) of normal operation of Hg control measures. [86]

v. The owner or operator shall maintain records of which Hg control devices/measure was being used during each operating day.

g. **112(r) Regulated Substances (Regulation 5.15)**

If anhydrous ammonia is present at the stationary source in an amount greater than the threshold quantity specified in Regulation 5.15, the owner or operator shall monitor the processes and keep records as required by Regulation 5.15. (Construction Permit 225-01-C)

h. **BART (40 CFR 52, Subpart S)**

i. The owner or operator shall maintain daily records of the hours of operation.

ii. The owner or operator shall, monthly, calculate and record the H_2SO_4 emissions on an average hourly basis for each operating calendar day.

S3. **Reporting** (Regulation 2.16, section 4.1.9.3)

The owner or operator shall submit quarterly compliance reports that include the information in this section.

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[85] In a letter dated October 4, 2016, LG&E demonstrated that in certain circumstance EGUs at this plant can meet the MACT mercury standard at zero PAC injection rate. Therefore the source is allowed to use flexible mercury control measures, including PAC injection or liquid additive system, to achieve compliance with MACT mercury standard.

[86] LG&E has established normal pH range per monitoring records during consecutive 180 days. On 10/20/2016, LG&E reported that the normal pH range for this unit is 4.8 – 6.4.

a. **NO_x**

i. The owner or operator shall identify all periods of exceeding a NO_x emission standard during a quarterly reporting period. The quarterly compliance report shall include the following:

1) Emission Unit ID number and emission point ID number;
2) Identification of all periods during which a deviation occurred;
3) A description, including the magnitude, of the deviation;
4) If known, the cause of the deviation;
5) A description of all corrective actions taken to abate the deviation; and
6) If no deviations occur during a quarterly reporting period, the report shall contain a negative declaration.

ii. The owner or operator shall submit a written report of excess emissions and the nature and cause of the excess emissions if known. The averaging period used for data reporting should correspond to the averaging period specified in the emission test method used to determine compliance with an emission standard for the pollutant/source category in question. All quarterly reports shall be postmarked by the 30th day following the end of each calendar quarter. The required report shall include: (Regulation 6.02, section 16.1)

1) For gaseous measurements, the summary shall consist of hourly averages in the units of the applicable standard. The hourly averages shall not appear in the written summary, but shall be made available electronically. (Regulation 6.02, section 16.3)

2) The data and time identifying each period during which the continuous monitoring system was inoperative, except for zero and span checks, and the nature of system repairs or adjustment shall be reported. Proof of continuous monitoring system performance whenever system repairs or adjustments have been made is required. (Regulation 6.02, section 16.4)

3) When no excess emissions have occurred and the continuous monitoring systems have been inoperative, repaired, or adjusted, such information shall be included in the report. (Regulation 6.02, section 16.5)

4) Owners or operators of affected facilities shall maintain a file of all information reported in the quarterly summaries, and all other data collected either by the continuous monitoring system or as necessary to convert monitoring data to the units of the applicable standard for a minimum of two years from the date of collection of such data or submission of such summaries. (Regulation 6.02, section 16.6)

iii. The owner or operator shall comply with the reporting requirements for the Acid Rain Permit No.176-97-AR (R4), specified in 40 CFR 75, Subpart G. Notifications, Monitoring Plans, Initial Certification and Recertification Applications, Quarterly Reports, Opacity Reports, Petitions to the Administrator, and Retired Unit Petitions shall be submitted as specified in Subpart G - reporting requirements. (See Attachment E)

iv. The owner or operator shall comply with the reporting requirements for the Title IV NO_x Budget Emission Limitation, 0.46 lb/MMBtu, as specified in 40 CFR Part 76.

v. Excess emissions for affected facilities using a CEMS for measuring NO_X are defined as: (40 CFR 60.45(g)(3))

1) For affected facilities electing not to comply with 40 CFR 60.44(e), any three-hour period during which the average emissions (arithmetic average of three contiguous one-hour periods) exceed the applicable standards in 40 CFR 60.44; or(40 CFR 60.45(g)(3)(i))

2) For affected facilities electing to comply with 40 CFR 60.44(e), any 30 operating day period during which the average emissions (arithmetic average of all one-hour periods during the 30 operating days) of NO_X as measured by a CEMS exceed the applicable standard in 40 CFR 60.44. (40 CFR 60.45(g)(3)(ii))

b. **SO_2**

i. The owner or operator shall identify all periods of exceeding a SO_2 emission standard during a quarterly reporting period. The report shall include the following:

1) Emission Unit ID number and emission point ID number;
2) Identification of all periods during which a deviation occurred;
3) A description, including the magnitude, of the deviation;
4) If known, the cause of the deviation;
5) A description of all corrective actions taken to abate the deviation; and
6) If no deviations occur during a quarterly reporting period, the report shall contain a negative declaration.

ii. The owner or operator shall submit a written report of excess emissions and the nature and cause of the excess emissions if known. See Specific Condition S3.a.ii.

iii. The owner or operator shall comply with the reporting requirements for the Acid Rain Permit No.176-97-AR (R4), specified in 40 CFR 75, Subpart G. Notifications, monitoring Plans, Initial Certification and Recertification Applications, Quarterly Reports, Opacity Reports, Petitions to the Administrator, and Retired Unit Petitions shall be submitted as specified in Subpart G - reporting requirements. (See Attachment E)

iv. Excess emissions for affected facilities are defined as: (40 CFR 60.45(g)(2))

1) For affected facilities electing not to comply with 40 CFR 60.43(d), any three-hour period during which the average emissions (arithmetic average of three contiguous one-hour periods) of SO_2 as measured by a CEMS exceed the applicable standard in 40 CFR 60.43; or (40 CFR 60.45(g)(2)(i))

2) For affected facilities electing to comply with 40 CFR 60.43(d), any 30 operating day period during which the average emissions (arithmetic average of all one-hour periods during the 30 operating days) of SO_2 as measured by a CEMS exceed the applicable standard in 40 CFR 60.43. (40 CFR 60.45(g)(2)(ii))

c. **PM**

i. The owner or operator shall identify all periods of exceeding a PM emission standard during a quarterly reporting period. The report shall include the following:

1) Emission Unit ID number and emission point ID number;
2) The date and duration (including the start and stop time) during which a deviation occurred;
3) The magnitude of excess emissions;
4) Description of the deviation and summary information on the cause or reason for excess emissions;
5) Corrective action taken to minimize the extent and duration of each excess emissions event;
6) Measures implemented to prevent reoccurrence of the situation that resulted in excess PM emissions; or
7) If no deviations occur during a quarterly reporting period, the report shall contain a negative declaration.

ii. The owner or operator shall submit a written report of excess emissions and the nature and cause of the excess emissions if known. See Specific Condition S3.a.ii.

iii. Excess emissions for affected facilities using a CEMS for measuring PM are defined as any boiler operating day period during which the average emissions (arithmetic average of all operating one-hour periods) exceed the applicable standards in 40 CFR 60.42. (40 CFR 60.45(g)(4))

d. **Opacity**

i. The owner or operator shall identify all periods of exceeding an opacity standard during a quarterly reporting period. The report shall include the following:

1) Any deviation from the requirement to perform daily (or monthly, if required) visible emission surveys or Method 9 tests and documented reason;
2) Any deviation from the requirement to record the results of each VE survey and Method 9 test performed and documented reason;
3) The number, date, and time of each VE Survey where visible emissions were observed and the results of the Method 9 test performed;
4) Identification of all periods of exceeding an opacity standard;
5) Description of any corrective action taken for each exceedance of the opacity standard; or
6) If no deviations occur during a quarterly reporting period, the report shall contain a negative declaration.

ii. The owner or operator shall comply with the reporting requirements for the Acid Rain Permit No.176-97-AR (R4), specified in 40 CFR 75, Subpart G. Notifications, monitoring Plans, Initial Certification and Recertification Applications, Quarterly Reports, Opacity Reports, Petitions to the Administrator, and Retired Unit Petitions shall be submitted as specified in Subpart G - reporting requirements. (See Attachment E) (Regulation 6.47, section 3.4 and 3.5 referencing 40 CFR Parts 75 and 76)

iii. Excess emissions are defined as any six-minute period during which the average opacity of emissions exceeds 20 percent opacity, except that one six-minute average per hour of up to 27 percent opacity need not be reported. (40 CFR 60.45(g)(1))

iv. <u>For coal silos (E8)</u>:

The owner or operator shall identify all periods of exceeding an opacity standard during a quarterly reporting period. The report shall include the following:

1) Emission Unit ID number, Stack ID number, and/or Emission point ID number;
2) The beginning and ending date of the reporting period;

3) The date, time and results of each exceedance of the opacity standard;
4) Description of any corrective action taken for each exceedance.

e. **TAC**

i. The owner or operator shall identify all periods of exceeding a TAC emission standard during a quarterly reporting period. The report shall include the following:

1) Emission Unit ID number and emission point ID number;
2) Identification of all periods during which a deviation occurred;
3) A description, including the magnitude, of the deviation;
4) If known, the cause of the deviation;
5) A description of all corrective actions taken to abate the deviation; and
6) If no deviations occur during a quarterly reporting period, the report shall contain a negative declaration.

ii. See Plantwide Requirements S2.b.

f. **HAP** (40 CFR 63, Subpart UUUUU)

i. The owner or operator shall comply with 40 CFR 63, Subpart UUUUU (See Attachment A) no later than April 16, 2016.

ii. Report normal pH range of reactant material in the FGD and normal range of any other parameters verified as having a direct effect on Hg emission within 30 days of establishing the normal range.

iii. The owner or operator shall identify all periods of the activated carbon injection rate are less than the minimum injection rate, or the pH of the reactant material in the FGD are out of normal range, or anytime other verified parameters are outside of their normal range, and any corrective action taken for each exceedance.

g. **112(r) Regulated Substances (Regulation 5.15)**

If anhydrous ammonia is present at the stationary source in an amount greater than the threshold quantity specified in Regulation 5.15, the owner or operator shall comply with the reporting requirements specified in Regulation 5.15. (Construction Permit 225-01-C)

h. **BART (40 CFR 52, Subpart S)**

The owner or operator shall identify all periods of exceeding a H_2SO_4 emission standard during a quarterly reporting period. The report shall include the following:

1) Emission Unit ID number and emission point ID number;
2) The date and duration (including the start and stop time) during which a deviation occurred;
3) The magnitude of excess emissions;
4) Description of the deviation and summary information on the cause or reason for excess emissions;
5) Corrective action taken to minimize the extent and duration of each excess emissions event;
6) Measures implemented to prevent reoccurrence of the situation that resulted in excess H_2SO_4 emissions; or
7) If no deviations occur during a quarterly reporting period, the report shall contain a negative declaration.

S4. **Testing** (Regulation 2.16, section 4.1.9.1)

a. **Control efficiency determination**

The owner or operator shall conduct performance test for the new EGU control device C30 and C31, according to the testing requirements in Attachment B, C, and G and Attachment C.[87,88] (Regulation 2.16, section 4.1.9.1) (See Comment 5 and 9)

U4 Comments

1. Boiler (E7) has TAC emission standards since its EA Demonstration was based on controlled PTE. If the controlled PTE for the TAC is less than de minimis level, De Minimis is listed as the basis of the limit. If the controlled PTE for the TAC is greater than de minimis level, modeling results were used to calculate risk value to compare to the EA Goals. In this case, controlled is used as the basis of the limit. TAC emissions for the coal silos (E8) are de minimis according to Regulation 5.21, section 2.1. The TAC emission limits determined by de minimis values shall be updated each time when the District revises the BAC/de minimis values for these TACs. The current de minimis values per TAC list revised on 10/14/2013 are as the following:

[87] Per an EPA rule change ("Restructuring of the Stationary Source Audit Program." Federal Register 75:176 (September 13, 2010) pp 55636-55657), if an audit sample is required by the test method, sources became responsible for obtaining the audit samples directly from accredited audit sample suppliers, not the regulatory agencies.

[88] According to permit 34595-12-C, the source is required to conduct stack tests to obtain the actual emission factors and control efficiencies.

TAC Name	CAS #	De minimis values	
		(lb/hr)	(lb/yr)
Benzene	71-43-2	0.243	216
Bromoform	75-25-2	0.4914	437
Methylene chloride	75-09-2	54	48,000
Tetrachloroethylene (Perc)	127-18-4	2.079	1,848
Toluene	108-88-3	2700	2,400,000
Xylene	1330-20-7	54	48,000
Hydrochloric acid	7647-01-0	10.8	9,600

Emission Unit U8: Fly ash storage & handling unit

U8 Applicable Regulations:

FEDERALLY ENFORCEABLE REGULATIONS		
Regulation	**Title**	**Applicable Sections**
7.08	Standards of Performance for New Affected Facilities	1, 2, 3, 4, 5, 6

DISTRICT ONLY ENFORCEABLE REGULATIONS		
Regulation	**Title**	**Applicable Sections**
5.00	Definitions	1, 2
5.01	General Provisions	1 through 2
5.20	Methodology for Determining Benchmark Ambient Concentration of a Toxic Air Contaminant	1 through 6
5.21	Environmental Acceptability for Toxic Air Contaminants	1 through 5
5.22	Procedures for Determining the Maximum Ambient Concentration of a Toxic Air Contaminant	1 through 5
5.23	Categories of Toxic Air Contaminants	1 through 6

U8 Equipment:[89]

Emission Point	Description	Applicable Regulation	Control ID	Stack ID
E13	One (1) flyash silo designated as Silo A, make Flex Kleen	5.00, 5.01, 5.20, 5.21, 5.22, 5.23, 7.08	C15	S13
	One (1) flyash silo designated as Silo B, make Wheelabrator-Fry		C16	S14
E31	Silo A dry truck load-out (75 tph) and silo B dry truck load-out (47.5 tph), make DCL		C37, C38	S42, S43
E32	Silo A railcar load-out, made Stephens Mfg.	5.00, 5.01, 5.20, 5.21, 5.22, 5.23, 7.08	C24	S22
	Silo B railcar load-out, made Stephens Mfg.		C25	S23
E33	Silo A and B wet truck load-out, make Ash Conveying Technologies		N/A	N/A

[89] This unit incorporated construction permit 143-05-C and 37-07-C for railcar loading process (E32), 144-05-C and 38-07-C for railcar loading baghouses (C24, C25), and 145-05-C for truck loading process (E31, E33).

U8 Control Devices:

ID	Description	Performance Indicator	Stack ID
C15	One (1) baghouse for Silo A, make Flex Kleen	Pressure drop range 0.1” to 5.0” water column	S13
C16	One (1) baghouse for Silo B, make Wheelabrator - Frye	Pressure drop range 0.1” to 5.0” water column	S14
C24	One (1) baghouse for Silo A railcar load-out, make Stephens Mfg	N/A (See Comment 1)	S22
C25	One (1) baghouse for Silo B railcar load-out, make Stephens Mfg	N/A (See Comment 1)	S23
C37	One (1) filter for Silo A and B air sliders, make DCL, model VML 185	N/A (See Comment 1)	S42
C38	One (1) filter for Silo A and B loading spout, make DCL, model CFM 330	N/A (See Comment 1)	S43

U8 Specific Conditions

S1. **Standards** (Regulation 2.16, section 4.1.1)

a. **PM**

i. The owner or operator shall not allow PM emissions from emission point E13 to exceed 34.9 lbs/hr based on actual operating hours in a calendar day.[90] (Regulation 7.08, section 3.3)

ii. The owner or operator shall not allow PM emissions from emission point E31 to exceed 32.4 lbs/hr based on actual operating hours in a calendar day..[90] (Regulation 7.08, section 3.3) (Permit 145-05-C)

iii. The owner or operator shall not allow PM emissions from emission point E32 to exceed 30.9 lbs/hr based on actual operating hours in a calendar day..[90] (Regulation 7.08, section 3.3) (Permit 144-05-C)

iv. The owner or operator shall not allow PM emissions from emission point E33 to exceed 38.6 lbs/hr based on actual operating hours in a calendar day..[90] (Regulation 7.08, section 3.3)

b. **Opacity**

The owner or operator shall not allow visible emissions to equal or exceed 20% opacity. (Regulation 7.08, section 3.1.1)

c. **TAC**

i. The owner or operator shall operate and maintain the baghouse for flyash silo (E13), as recommended by the manufacturer, at all times the process equipment is in operation, including periods of startup, shutdown, and malfunction, in a manner consistent with good air pollution control practice to meet the standards. (Regulation 2.16, section 4.1.1)

ii. The owner or operator shall not allow TAC emissions for flyash silo (E13) to exceed the TAC emission standards listed in the following table.[91] (Regulation 5.21, section 4.2 and section 4.3) (See Comment 1)

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[90] It has been demonstrated that the PM emissions cannot exceed the PM standards specified in Regulation 7.08 uncontrolled. However, there are monitoring, record keeping and reporting requirements associated with any times that the control devices are not in place and the process is operated. STAR limits are based upon controlled emissions.

[91] This table for TAC emission standards has been revised to exclude Category 3 and 4 TACs for existing sources and use "de minimis values", instead of actual numbers for current de minimis levels, as emission standards.

TAC	CAS #	TAC Limits Determination	
		(lbs/yr)	Basis of Limits
Arsenic	7440-38-2	1.20	Controlled PTE
Cadmium	7440-43-9	De minimis values (See Comment 1)	De Minimis
Chromium III	16065-83-1		De Minimis
Chromium VI	7440-47-3		De Minimis
Nickel	7440-02-0		De Minimis
Cobalt	7440-48-4		De Minimis
Lead	7439-92-1		De Minimis
Manganese	7439-96-5		De Minimis

iii. See Plantwide Requirements S1.b.

S2. **Monitoring and Record Keeping** (Regulation 2.16, sections 4.1.9.1 and 4.1.9.2)

The owner or operator shall maintain the required records for a minimum of 5 years and make the records readily available to the District upon request.

a. **PM**

There are no routine monitoring and record keeping requirements for this pollutant.

b. **Opacity**

i. The owner or operator shall conduct a monthly one-minute visible emissions survey, during normal operation, of the emission points. No more than four emission points shall be observed simultaneously. The opacity surveys can be performed on the building exhaust points if the process is inside an enclosure.

ii. At emission points where visible emissions are observed, the owner or operator shall initiate corrective action within eight hours of the initial observation. If correction actions are taken then a follow-up visible emission survey shall be made. If the visible emissions persist, the owner or operator shall perform or cause to be performed a Method 9, in accordance with 40 CFR Part 60, Appendix A, within 24 hours of the initial observation.

iii. The owner or operator shall maintain records, monthly, of the results of all visible emissions surveys and tests. Records of the results of any visible emissions survey shall include the date of the survey, the name of the person conducting the survey, whether or not visible emissions were observed, and what if any corrective action was performed. If an emission point is not being operated during a given month, then no visible emission survey needs to be performed and a negative declaration shall be entered in the record.

c. **TAC**

i. The owner or operator shall perform sampling and lab analysis for the flyash in order to determine the TAC concentrations, at least once every six months.

ii. The owner or operator shall calculate the TAC emissions at least once every six months. The average TAC concentrations of all sampling results during the previous 12 months combined with the sampling results from the current semiannual period shall be used for emission calculations.

iii. The owner or operator shall monitor and record the pressure drop across baghouse C15 and C16, which is used as the indicator of normal operation of the baghouses, at least once each per operating day. The normal pressure drop range for C15 and C16 is 0.1” to 5.0” water column.

iv. The owner or operator shall maintain daily records of any periods of time where the process was operating and the baghouse C15 or C16 was not operating or a declaration that the baghouse operated at all times that day when the process was operating.

v. If there is any time that the baghouse C15 or C16 is bypassed or not in operation, such as the filters are not in place, etc, when the process is operating, then the owner or operator shall keep a record of the following for each bypass event:

1) Date;
2) Start time and stop time;
3) Identification of the baghouse and process equipment;
4) TAC emissions during the bypass in lb/hr;
5) Summary of the cause or reason for each bypass event;
6) Corrective action taken to minimize the extent or duration of the bypass event; and
7) Measures implemented to prevent reoccurrence of the situation that resulted in the bypass event.

vi. See Plantwide Requirements S2.b.

S3. **Reporting** (Regulation 2.16, section 4.1.9.3)

The owner or operator shall submit quarterly compliance reports that include the information in this section.

a. **PM**

There are no routine reporting requirements for this pollutant.

b. **Opacity**

The owner or operator shall identify all periods of exceeding an opacity standard during a quarterly reporting period. The report shall include the following:

1) Any deviation from the requirement to perform daily (or monthly, if required) visible emission surveys or Method 9 tests;
2) Any deviation from the requirement to record the results of each VE survey and Method 9 test performed;
3) The date and time of each VE Survey where visible emissions were observed and the results of any Method 9 test performed;
4) The date, time and results of follow-up VE survey;
5) The date, time, and results of any Method 9 test performed;
6) Identification of all periods of exceeding an opacity standard; and
7) If no deviations occur during a quarterly reporting period, the report shall contain a negative declaration.

c. **TAC**

i. The owner or operator shall identify all periods of the pressure drop across the baghouse C15 and C16 exceeding the normal range and any corrective action taken for each exceedance.

ii. The owner or operator shall report the following information regarding By-Pass Activity in the quarterly compliance reports.

1) Number of times the vent stream by-passes the baghouse C15 or C16 and is vented to the atmosphere;
2) Duration of each by-pass to the atmosphere;
3) Calculated pound per hour TAC emissions for each by-pass; or
4) A negative declaration if no by-passes occurred.

iii. See Plantwide Requirements S2.b.

U8 Comments

1. The flyash silo (E13) has TAC emission standards since its EA Demonstration was based on controlled PTE. If the controlled PTE for the TAC is less than de minimis level, use De Minimis as limit. If the controlled PTE for the TAC is greater than de minimis level, modeling results were used to calculate risk value to compare to the EA Goals. In this case, controlled is used as limit. The TAC emission limits determined by de minimis values shall be updated each time when the District revises the BAC/de minimis values for these TACs. The current de minimis values per TAC list revised on 10/14/2013 are as the following:

TAC Name	CAS #	De minimis values (lb/hr)	(lb/yr)
Cadmium	7440-43-9	0.0003	0.27
Chromium III	16065-83-1	0.1	109.5
Chromium VI	7440-47-3	4.5E-05	0.040
Nickel	7440-02-0	0.0021	1.82
Cobalt	7440-48-4	0.00022	0.192
Lead	7439-92-1	0.043	38.4
Manganese	7439-96-5	0.027	24

Emission Unit U9: Fly ash transfer bins

U9 Applicable Regulations:

FEDERALLY ENFORCEABLE REGULATIONS		
Regulation	**Title**	**Applicable Sections**
7.08	Standards of Performance for New Affected Facilities	1, 2, 3, 4, 5, 6

DISTRICT ONLY ENFORCEABLE REGULATIONS		
Regulation	**Title**	**Applicable Sections**
5.00	Definitions	1, 2
5.01	General Provisions	1 through 2
5.20	Methodology for Determining Benchmark Ambient Concentration of a Toxic Air Contaminant	1 through 6
5.21	Environmental Acceptability for Toxic Air Contaminants	1 through 5
5.22	Procedures for Determining the Maximum Ambient Concentration of a Toxic Air Contaminant	1 through 5
5.23	Categories of Toxic Air Contaminants	1 through 6

U9 Equipment:

Emission Point	Description	Applicable Regulation	Control ID	Stack ID
E16	One (1) flyash transfer bin with two (2) separators for Unit 1 and 2. Total capacity of transfer bin E16, E17, and E18 is 80.5 tph.	5.00, 5.01, 5.20, 5.21, 5.22, 5.23, 7.08	C19	S17, S24, S25
E17	One (1) flyash transfer bin with two (2) separators for Unit 3.		C20	S18, S26, S27
E18	One (1) flyash transfer bin with two (2) separators for Unit 4.		C21	S19, S28, S29

U9 Control Devices:

ID	Description	Performance Indicator	Stack ID
C19	One (1) baghouse for Unit 1 & 2 transfer bin, make Mikro-Pulsaire	Pressure drop range 1.0” to 6.0” water column [92]	S17, S24, S25
C20	One (1) baghouse for Unit 3 transfer bin, make Mikro-Pulsaire		S18, S26, S27
C21	One (1) baghouse for Unit 4 transfer bin, make Mikro-Pulsaire		S19, S28, S29

[92] According to permit 145-97-TV (R1), LG&E has established the normal pressure drop range for the baghouses after ninety (90) consecutive days of observation and submitted the report on March 11, 2015. LG&E revised the normal pressure drop range on November 1, 2016.

U9 Specific Conditions

S1. **Standards** (Regulation 2.16, section 4.1.1)

a. **PM**

The owner or operator shall not allow PM emissions from emission point E16, E17, or E18 to exceed 34.9 lbs/hr for all three emission points combined based on actual operating hours in a calendar day.[93] (Regulation 7.08, section 3.3)

b. **Opacity**

The owner or operator shall not allow visible emissions to equal or exceed 20% opacity. (Regulation 7.08, section 3.1.1)

c. **TAC**

i. The owner or operator shall operate and maintain the baghouses, as recommended by the manufacturer, at all times the process equipment is in operation, including periods of startup, shutdown, and malfunction, in a manner consistent with good air pollution control practice to meet the standards. (Regulation 2.16, section 4.1.1)

ii. The owner or operator shall not allow TAC emissions for this unit to exceed the TAC emission standards determined based upon the EA Demo provided to the District.[94] (Regulation 5.21, section 4.2 and section 4.3) (See Comment 1)

TAC	CAS #	TAC Limits Determination	
		(lbs/yr)	Basis of Limits
Arsenic	7440-38-2	1.20	Controlled PTE
Cadmium	7440-43-9	De minimis values (See Comment 1)	De Minimis
Chromium III	16065-83-1		De Minimis
Chromium VI	7440-47-3		De Minimis
Nickel	7440-02-0		De Minimis
Cobalt	7440-48-4		De Minimis
Lead	7439-92-1		De Minimis
Manganese	7439-96-5		De Minimis

iii. See Plantwide Requirements S1.b.

[93] It has been demonstrated that the PM emissions cannot exceed the PM standards specified in Regulation 7.08 uncontrolled

[94] This table for TAC emission standards has been revised to exclude Category 3 and 4 TACs for existing sources and use “de minimis values”, instead of actual numbers for current de minimis levels, as emission standards.

S2. **Monitoring and Record Keeping** (Regulation 2.16, sections 4.1.9.1 and 4.1.9.2)

The owner or operator shall maintain the required records for a minimum of 5 years and make the records readily available to the District upon request.

a. **PM**

There are no routine monitoring and record keeping requirements for this pollutant.

b. **Opacity**

i. The owner or operator shall conduct a monthly one-minute visible emissions survey, during normal operation, of the emission points. No more than four emission points shall be observed simultaneously. The opacity surveys can be performed on the building exhaust points if the process is inside an enclosure.

ii. At emission points where visible emissions are observed, the owner or operator shall initiate corrective action within eight hours of the initial observation. If correction actions are taken then a follow-up visible emission survey shall be made. If the visible emissions persist, the owner or operator shall perform or cause to be performed a Method 9, in accordance with 40 CFR Part 60, Appendix A, 24 hours of the initial observation.

iii. The owner or operator shall maintain records, monthly, of the results of all visible emissions surveys and tests. Records of the results of any visible emissions survey shall include the date of the survey, the name of the person conducting the survey, whether or not visible emissions were observed, and what if any corrective action was performed. If an emission point is not being operated during a given month, then no visible emission survey needs to be performed and a negative declaration shall be entered in the record.

c. **TAC**

i. The owner or operator shall perform sampling and lab analysis for the flyash in order to determine the TAC concentrations, at least once every six months.

ii. The owner or operator shall calculate the TAC emissions at least once every six months. The average TAC concentrations of all sampling results during the previous 12 months combined with the sampling results from the current semiannual period shall be used for emission calculations.

iii. The owner or operator shall monitor and record the pressure drop across baghouses. The normal pressure drop range for the baghouses is 1.0” to 6.0” water column.

iv. The owner or operator shall maintain daily records of any periods of time where the process was operating and the baghouse was not operating or a declaration that the baghouse operated at all times that day when the process was operating.

v. If there is any time that the baghouse is bypassed or not in operation, such as the filters are not in place, etc, when the process is operating, then the owner or operator shall keep a record of the following for each bypass event:

1) Date;
2) Start time and stop time;
3) Identification of the baghouse and process equipment;
4) TAC emissions during the bypass in lb/hr;
5) Summary of the cause or reason for each bypass event;
6) Corrective action taken to minimize the extent or duration of the bypass event; and
7) Measures implemented to prevent reoccurrence of the situation that resulted in the bypass event.

vi. See Plantwide Requirements S2.b.

S3. **Reporting** (Regulation 2.16, section 4.1.9.3)

The owner or operator shall submit quarterly compliance reports that include the information in this section.

a. **PM**

There are no routine reporting requirements for this pollutant.

b. **Opacity**

The owner or operator shall identify all periods of exceeding an opacity standard during a quarterly reporting period. The report shall include the following:

1) Any deviation from the requirement to perform daily (or monthly, if required) visible emission surveys or Method 9 tests;
2) Any deviation from the requirement to record the results of each VE survey and Method 9 test performed;
3) The date and time of each VE Survey where visible emissions were observed and the results of any Method 9 test performed;
4) The date, time and results of follow-up VE survey;

5) The date, time, and results of any Method 9 test performed;
6) Identification of all periods of exceeding an opacity standard; and
7) If no deviations occur during a quarterly reporting period, the report shall contain a negative declaration.

c. **TAC**

i. The owner or operator shall identify all periods of the pressure drop across the baghouses exceeding the normal range and any corrective action taken for each exceedance.

ii. The owner or operator shall report the following information regarding By-Pass Activity in the quarterly compliance reports.

1) Number of times the vent stream by-passes the baghouse and is vented to the atmosphere;
2) Duration of each by-pass to the atmosphere;
3) Calculated pound per hour TAC emissions for each by-pass; or
4) A negative declaration if no by-passes occurred.

iii. See Plantwide Requirements S2.b.

U9 Comments

1. This unit has TAC emission standards since its EA Demonstration was based on controlled PTE. If the controlled PTE for the TAC is less than de minimis level, use De Minimis as limit. If the controlled PTE for the TAC is greater than de minimis level, modeling results were used to calculate risk value to compare to the EA Goals. In this case, controlled is used as limit. The TAC emission limits determined by de minimis values shall be updated each time when the District revises the BAC/de minimis values for these TACs. The current de minimis values per TAC list revised on 10/14/2013 are as the following:

TAC Name	CAS #	De minimis values	
		(lb/hr)	(lb/yr)
Cadmium	7440-43-9	0.0003	0.27
Chromium III	16065-83-1	0.1	109.5
Chromium VI	7440-47-3	4.5E-05	0.040
Nickel	7440-02-0	0.0021	1.82
Cobalt	7440-48-4	0.00022	0.192
Lead	7439-92-1	0.043	38.4
Manganese	7439-96-5	0.027	24

Emission Unit U12: Limestone processing operation

U12 Applicable Regulations:

FEDERALLY ENFORCEABLE REGULATIONS		
Regulation	**Title**	**Applicable Sections**
7.08	Standards of Performance for New Affected Facilities	1, 2, 3
40 CFR 60 Subpart OOO	Standards of Performance for Nonmetallic Mineral Processing Plants	60.670, 60.671, 60.672(b)(e), 60.673, 60.675(d), 60.676(f)(j)

DISTRICT ONLY ENFORCEABLE REGULATIONS		
Regulation	**Title**	**Applicable Sections**
7.02	Federal New Source Performance Standards Incorporated by Reference	1.1, 1.72, 2, 3, 4, 5

U12 Equipment:[95]

Emission Point	Description	Applicable Regulation	Control ID	Stack ID
E24	One (1) barge unloading operation with unloading hopper, rated capacity 750 tph	7.08	N/A	N/A
E25	One (1) transfer point from conveyor to storage pile with receiving rate capacity 1,000 tph	7.08, 40 CFR 60 Subpart OOO	N/A	N/A
E26	One (1) belt conveyor LA, rated capacity 1000 tph, from hopper to belt conveyor LB	7.08, 40 CFR 60 Subpart OOO	N/A	N/A
E27	One (1) belt conveyor LB, rated capacity 1000 tph, from belt conveyor LA to storage pile	7.08, 40 CFR 60 Subpart OOO	N/A	N/A
E28	Three (3) limestone crushers* with a total capacity 145 tph	7.08, 40 CFR 60 Subpart OOO	N/A	N/A
* Limestone grinding building contains three (3) limestone slurry units, Unit A, B, and C. Each unit consists of crusher, ball mill, separating tank, mill slurry classifier, and mill slurry tank. Since water is added to the crusher to make slurry, there are no emissions from ball mills, separating tanks, slurry classifiers, and mill slurry tanks. [96]				

U12 Control Devices:

There is no control device associated with this unit.

[95] This unit is not subject to STAR since it does not have any TAC emissions.

[96] Limestone slurry unit, Unit C, was previously permitted under construction permit 30399-11-C.

U12 Specific Conditions

S1. **Standards** (Regulation 2.16, section 4.1.1)

a. **PM**

i. The owner or operator shall not allow PM emissions to exceed 49.9 lb/hr from emission point E24 based on actual operating hours in a calendar day.[97] (Regulation 7.08, section 3.1.2)

ii. The owner or operator shall not allow PM emissions to exceed 52.3 lb/hr from each emission point E25, E26, and E27 based on actual operating hours in a calendar day.[97] (Regulation 7.08, section 3.1.2)

iii. The owner or operator shall not allow PM emissions to exceed 38.4 lb/hr from E28 (Unit A, B, C combined) and 31.8 lb/hr from Unit C only based on actual operating hours in a calendar day.[97] (Regulation 7.08, section 3.1.2)

b. **Opacity**

i. For emission point E24, E25, E26, E27, and E28, the owner or operator shall not allow visible emissions to equal or exceed 20% opacity. (Regulation 7.08, section 3.1.1)

ii. For emission point E25, E26, and E27, the owner or operator shall not allow visible emissions to equal or exceed 10% opacity.[98] (40 CFR 60. 672(b) and Table 2 to Subpart OOO of Part 60)

iii. For emission point E28, Unit A and B crushers, the owner or operator shall not allow visible emission to equal or exceed 15% opacity.[98] (40 CFR 60.672(b) and Table 2 to Subpart OOO of Part 60)

iv. For emission point E28, Unit C crusher, the owner or operator shall not allow visible emission to equal or exceed 12% opacity.[98] (40 CFR 60. 672(b) and Table 2 to Subpart OOO of Part 60)

S2. **Monitoring and Record Keeping** (Regulation 2.16, sections 4.1.9.1 and 4.1.9.2)

The owner or operator shall maintain the required records for a minimum of 5 years and make the records readily available to the District upon request.

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[97] It has been demonstrated that the PM emissions cannot exceed the PM standards specified in Regulation 7.08 uncontrolled.

[98] By demonstrating compliance with the opacity requirements in these conditions it also demonstrates compliance with the 20% opacity requirement in Regulation 7.08.

a. **PM**

There are no routine monitoring and record keeping requirements for this pollutant.

b. **Opacity**

i. The owner or operator shall conduct a monthly one-minute visible emissions survey, during normal operation, of the emission points. No more than four emission points shall be observed simultaneously. The opacity surveys can be performed on the building exhaust points if the process is inside an enclosure.

ii. At emission points where visible emissions are observed, the owner or operator shall initiate corrective action within eight hours of the initial observation. If the visible emissions persist, the owner or operator shall perform or cause to be performed a Method 9, in accordance with 40 CFR Part 60, Appendix A, within 24 hours of the initial observation.

iii. The owner or operator shall maintain records, monthly, of the results of all visible emissions surveys and tests. Records of the results of any visible emissions survey shall include the date of the survey, the name of the person conducting the survey, whether or not visible emissions were observed, and what if any corrective action was performed. If an emission point is not being operated during a given month, then no visible emission survey needs to be performed and a negative declaration shall be entered in the record.

S3. **Reporting** (Regulation 2.16, section 4.1.9.3)

The owner or operator shall submit quarterly compliance reports that include the information in this section.

a. **PM**

There are no routine reporting requirements for this process.

b. **Opacity**

The owner or operator shall identify all periods of exceeding an opacity standard during a quarterly reporting period. The report shall include the following:

i. Any deviation from the requirement to perform and record the results of visible emission surveys or Method 9 tests;
ii. The number, date, and time of each visible emissions survey where visible emissions were observed and the results of the Method 9 test performed;

iii. Identification of all periods of exceeding the opacity standard; and
iv. Description of any corrective action taken for each exceedance of the opacity standard.

S4. **Testing** (Regulation 2.16, section 4.1.9.3)

E28, Unit C crusher is subject to the following testing requirements:

Opacity

i. The owner or operator shall perform an *initial performance* test to demonstrate compliance with the opacity limit by initially conducting a test in accordance with Method 9 of 40 CFR 60 Appendix A within 180 days of achieving normal operation.[99] (40 CFR 60.672(b))

ii. The owner or operator shall conduct a *repeat performance test* according to Method 9 within 5 years from the initial performance test. (40 CFR 60. 672(b))

iii. The owner or operator shall use Method 9 of Appendix A–4 of 40 CFR 60 and the procedures in 40 CFR 60.11, with the following additions:

1) The minimum distance between the observer and the emission source shall be 4.57 meters (15 feet). (40 CFR 60.675(c)(1)(i))

2) The observer shall, when possible, select a position that minimizes interference from other fugitive emission sources (*e.g.*, road dust). The required observer position relative to the sun (Method 9 of Appendix A–4 of this part, Section 2.1) must be followed. (40 CFR 60.675(c)(1)(ii))

iv. The test shall be performed at maximum capacity or allowable/permitted capacity or at a level of capacity which results in the greatest emissions and is representative of the operations. Failure to perform the test at these conditions may necessitate a re-test. The maximum 6-minute average opacity exhibited during the test period shall be used to determine whether the affected source is in initial compliance with the standard. The duration of the Method 9 performance test shall be 3 hours (30 6-minute averages).

v. The owner or operator shall provide the District a 7-day advance notification for this Method 9 test. (40 CFR 60. 675(g))

[99] The initial performance testing for this unit was conducted on November 28, 2012 and the result of this performance was submitted to the District on January 9, 2013.

vi. The owner or operator shall furnish the District with a written report of the results of the compliance test(s) within 60 days following the actual date of the compliance test(s).

Emission Unit U14: Cooling tower

U14 Applicable Regulations:

FEDERALLY ENFORCEABLE REGULATIONS		
Regulation	**Title**	**Applicable Sections**
7.08	Standards of Performance for New Affected Facilities	1, 2, 3

U14 Equipment:[100]

Emission Point	Description	Applicable Regulation	Control ID	Stack ID
E38	One (1) cooling tower for Unit 4 boiler, make Zurn, model 12Z-3300, capacity 222,600 gallon water per minute.	7.08	N/A	N/A

U14 Control Devices:

There is no control device associated with this unit.

[100] This unit is not subject to STAR since it does not have any TAC emissions.

U14 Specific Conditions

S1. **Standards** (Regulation 2.16, section 4.1.1)

a. **PM**

The owner or operator shall not allow PM emissions to exceed 97.9 lb/hr from this emission unit based on actual operating hours in a calendar day.[101] (Title V Application, November 30, 2007)

b. **Opacity**

The owner or operator shall not allow visible emissions to equal or exceed 20% opacity. (Regulation 7.08, section 3.1.1)

S2. **Monitoring and Record Keeping** (Regulation 2.16, sections 4.1.9.1 and 4.1.9.2)

The owner or operator shall maintain the required records for a minimum of 5 years and make the records readily available to the District upon request.

a. **PM**

There are no monitoring or record keeping requirements for this pollutant.

b. **Opacity**

There are no monitoring or record keeping requirements for this pollutant.[102]

S3. **Reporting** (Regulation 2.16, section 4.1.9.3)

The owner or operator shall submit quarterly compliance reports that include the information in this section.

a. **PM**

There are no routine reporting requirements for this process.

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[101] The PM standards is determined based on the capacity (202,000 gal/min) listed in the Title V Renewal Application submitted in 2007. LG&E submitted an application on July 21, 2014 to request the capacity to be revised from 202,000 gal/min to 222,600 gal/min. LG&E did not request to change the standard based on the higher capacity. It has been demonstrated that the PM emissions cannot exceed the PM standards specified in Regulation 7.08 uncontrolled. Therefore there are no monitoring, record keeping, and reporting requirements with respect to the PM lb/hr emission standards.

[102] Testing for opacity is not required for this unit due to the nature of the cooling tower.

b. **Opacity**

There are no routine reporting requirements for this process.

Emission Unit U15: Haul Roads

U15 Applicable Regulations:

FEDERALLY ENFORCEABLE REGULATIONS		
Regulation	**Title**	**Applicable Sections**
1.14	Control of Fugitive Particulate Emissions	1, 2, 3, 4, 8, 9

U15 Equipment:[103]

Emission Point	Description	Applicable Regulation	Control ID	Stack ID
E39a	Paved road particulate emissions	1.14	N/A	N/A
E39b	Unpaved road particulate emissions	1.14	N/A	N/A

U15 Control Devices:

Particulate emissions from unpaved road are controlled according to an approved Fugitive Dust Control Plan for Paved & Unpaved Roads.[104] (See Attachment F)

[103] This unit is not subject to STAR since it does not have any TAC emissions.

[104] LG&E submitted a plantwide Fugitive Dust Control Plan on June 28, 2013 and the District approved the plan on 06/05/2014.

U15 Specific Conditions

S1. **Standards** (Regulation 2.16, section 4.1.1)

a. **PM**

The owner or operator shall not allow a road to be used without taking reasonable precautions to prevent particulate matter from becoming airborne beyond the work site. Such precautions shall include, where applicable, but shall not be limited to the following: (Regulation 1.14, section 2.1)

i. Applying and maintaining asphalt, oil, water, or suitable chemicals on roads, materials stockpiles, and other surfaces which can create airborne dusts, (Regulation 1.14, section 2.1.2)

ii. Covering at all times, except when loading and unloading, open bodied trucks transporting materials likely to become airborne, (Regulation 1.14, section 2.1.4)

iii. Maintaining paved roadways in a clean condition, (Regulation 1.14, section 2.1.6)

iv. Removing earth or other material from paved streets which earth or other material has been transported thereto by trucking or earth moving equipment or erosion by water. (Regulation 1.14, section 2.1.7)

b. **Opacity**

i. The owner or operator shall not allow visible emissions to equal or exceed 20% opacity. (Regulation 1.14, section 2.3)

ii. The owner or operator shall not allow visible fugitive emissions beyond the lot line of the property on which the emissions originate. (Regulation 1.14, section 2.4)

S2. **Monitoring and Record Keeping** (Regulation 2.16, sections 4.1.9.1 and 4.1.9.2)

The owner or operator shall maintain the required records for a minimum of 5 years and make the records readily available to the District upon request.

a. **PM**

The owner or operator shall keep records of vehicle miles traveled (VMT) and weights for the vehicles traveled on unpaved and paved roads.

b. **Opacity**

See Specific Condition S2.a.

S3. **Reporting** (Regulation 2.16, section 4.1.9.3)

The owner or operator shall submit quarterly compliance reports that include the information in this section.

a. **PM/ Opacity**

The owner or operator shall report any deviation from the attached Fugitive Dust Control Plan during the reporting period.

Emission Unit U16: Sorbent storage silos

U16 Applicable Regulations:

FEDERALLY ENFORCEABLE REGULATIONS		
Regulation	**Title**	**Applicable Sections**
7.08	Standards of Performance for New Affected Facilities	1, 2, 3, 4, 5, 6

U16 Equipment:[105,106]

Emission Point	Description	Applicable Regulation	Control ID	Stack ID
E40a – E40h	Six (6) to eight (8) sorbent silos for dry sorbent or Trona, make BCSI, model BCSI-14. Each silo has a capacity of 120 tons, loading rate 40 tons/hr, and equipped with a bin vent filter.	7.08	C32a – C32h	S35a – S35h

U16 Control Devices:

ID	Description	Performance Indicator	Stack ID
C32a – C32h	Six (6) to eight (8) bin vent filters each controlling a sorbent storage silo, make BCSI, model BV25-96	N/A[107]	S35a – S35h

[105] This unit was previously permitted under construction permit 34658-12-C.

[106] This unit is not subject to STAR since it does not have any TAC emissions.

[107] The bin vent filter equipped for each silo is considered as an integrated component of the silo. However, there are monitoring, record keeping and reporting requirements associated with any times that the filters are not in place and the process is operated.

U16 Specific Conditions

S1. **Standards** (Regulation 2.16, section 4.1.1)

a. **PM**

i. The owner or operator shall not allow PM emissions from each of the emission points E40a through E40h to exceed 6.9 lbs/hr based on actual operating hours in a calendar day. (Regulation 7.08, section 3.3)

ii. The owner or operator shall maintain the bin vent filters in place at all times the process equipment is in operation, including periods of startup, shutdown, and malfunction, in a manner consistent with good air pollution control practice to meet the standards. (Regulation 2.16, section 4.1.1)

b. **Opacity**

The owner or operator shall not allow visible emissions to equal or exceed 20% opacity. (Regulation 7.08, section 3.1.1)

S2. **Monitoring and Record Keeping** (Regulation 2.16, sections 4.1.9.1 and 4.1.9.2)

The owner or operator shall maintain the required records for a minimum of 5 years and make the records readily available to the District upon request.

a. **PM**

i. The owner or operator shall maintain monthly records of the type and amount of material throughput for each piece of equipment.

ii. The owner or operator shall monthly perform a visual inspection of the structural and mechanical integrity of the bin vent filters for signs of damage, air leakage, corrosion, or other equipment defects, and repair and/or replace defective components as needed. The owner or operator shall maintain monthly records of the results.

iii. The owner or operator shall maintain daily records of any periods of time where the process was operating and the bin vent filters were not in place or a declaration that the bin vent filters were in place at all times that day when the process was operating.

iv. If there is any time that the bin vent filters are not in place when the process is operating, then the owner or operator shall keep a record of the following for each bypass event:

1) Date;
2) Start time and stop time;

3) Identification of the bin vent filters and process equipment;
4) PM emissions during the bypass in lb/hr;
5) Summary of the cause or reason for each bypass event;
6) Corrective action taken to minimize the extent or duration of the bypass event; and
7) Measures implemented to prevent reoccurrence of the situation that resulted in the bypass event.

b. **Opacity**

i. The owner or operator shall conduct a monthly one-minute visible emissions survey, during normal operation, of the emission points. No more than four emission points shall be observed simultaneously. The opacity surveys can be performed on the building exhaust points if the process is inside an enclosure.

ii. At emission points where visible emissions are observed, the owner or operator shall initiate corrective action within eight hours of the initial observation. If correction actions are taken then a follow-up visible emission survey shall be made. If the visible emissions persist, the owner or operator shall perform or cause to be performed a Method 9, in accordance with 40 CFR Part 60, Appendix A, 24 hours of the initial observation.

iii. The owner or operator shall maintain records, monthly, of the results of all visible emissions surveys and tests. Records of the results of any visible emissions survey shall include the date of the survey, the name of the person conducting the survey, whether or not visible emissions were observed, and what if any corrective action was performed. If an emission point is not being operated during a given month, then no visible emission survey needs to be performed and a negative declaration shall be entered in the record.

S3. **Reporting** (Regulation 2.16, section 4.1.9.3)

The owner or operator shall submit quarterly compliance reports that include the information in this section.

a. **PM**

The owner or operator shall report the following information regarding PM By-Pass Activity in the quarterly compliance reports.

1) Number of times the PM vent stream by-passes the bin vent filters and is vented to the atmosphere;
2) Duration of each by-pass to the atmosphere;
3) Calculated pound per hour PM emissions for each by-pass; or

4) A negative declaration if no by-passes occurred.

b. **Opacity**

The owner or operator shall identify all periods of exceeding an opacity standard during a quarterly reporting period. The report shall include the following:

1) Any deviation from the requirement to perform daily (or monthly, if required) visible emission surveys or Method 9 tests;
2) Any deviation from the requirement to record the results of each VE survey and Method 9 test performed;
3) The date and time of each VE Survey where visible emissions were observed and the results of any Method 9 test performed;
4) The date, time and results of follow-up VE survey;
5) The date, time, and results of any Method 9 test performed;
6) Identification of all periods of exceeding an opacity standard; and
7) If no deviations occur during a quarterly reporting period, the report shall contain a negative declaration.

Emission Unit U17: PAC storage silos

U17 Applicable Regulations:

FEDERALLY ENFORCEABLE REGULATIONS		
Regulation	**Title**	**Applicable Sections**
7.08	Standards of Performance for New Affected Facilities	1, 2, 3, 4, 5, 6

U17 Equipment:[108,109]

Emission Point	Description	Applicable Regulation	Control ID	Stack ID
E41a – E41f	Four (4) to six (6) PAC silos for PAC injection system, make BCSI, model BCSI-14. Each silo has a capacity of 94 tons, loading rate 40 tons/hr, and equipped with a bin vent filter.	7.08	C33a – C33f	S36a – S36f

U17 Control Devices:

ID	Description	Performance Indicator	Stack ID
C33a – C33f	Four (4) to six (6) bin vent filters each controlling a PAC storage silo, make BCSI, model BV25-96	N/A[110]	S36a – S36f

[108] This unit was previously permitted under construction permit 34658-12-C.

[109] This unit is not subject to STAR since it does not have any TAC emissions.

[110] The bin vent filter equipped for each silo is considered as an integrated component of the silo. However, there are monitoring, record keeping and reporting requirements associated with any times that the filters are not in place and the process is operated.

U17 Specific Conditions

S1. **Standards** (Regulation 2.16, section 4.1.1)

a. **PM**

i. The owner or operator shall not allow PM emissions from each of the emission points E41a through E41f to exceed 9.7 lbs/hr based on actual operating hours in a calendar day. (Regulation 7.08, section 3.3)

ii. The owner or operator shall maintain the bin vent filters in place at all times the process equipment is in operation, including periods of startup, shutdown, and malfunction, in a manner consistent with good air pollution control practice to meet the standards. (Regulation 2.16, section 4.1.1)

b. **Opacity**

The owner or operator shall not allow visible emissions to equal or exceed 20% opacity. (Regulation 7.08, section 3.1.1)

S2. **Monitoring and Record Keeping** (Regulation 2.16, sections 4.1.9.1 and 4.1.9.2)

The owner or operator shall maintain the required records for a minimum of 5 years and make the records readily available to the District upon request.

a. **PM**

i. The owner or operator shall maintain monthly records of the type and amount of material throughput for each piece of equipment.

ii. The owner or operator shall monthly perform a visual inspection of the structural and mechanical integrity of the bin vent filters for signs of damage, air leakage, corrosion, or other equipment defects, and repair and/or replace defective components as needed. The owner or operator shall maintain monthly records of the results.

iii. The owner or operator shall maintain daily records of any periods of time where the process was operating and the bin vent filters were not in place or a declaration that the bin vent filters were in place at all times that day when the process was operating.

iv. If there is any time that the bin vent filters are not in place when the process is operating, then the owner or operator shall keep a record of the following for each bypass event:

1) Date;
2) Start time and stop time;

3) Identification of the bin vent filters and process equipment;
4) PM emissions during the bypass in lb/hr;
5) Summary of the cause or reason for each bypass event;
6) Corrective action taken to minimize the extent or duration of the bypass event; and
7) Measures implemented to prevent reoccurrence of the situation that resulted in the bypass event.

b. **Opacity**

i. The owner or operator shall conduct a monthly one-minute visible emissions survey, during normal operation, of the emission points. No more than four emission points shall be observed simultaneously. The opacity surveys can be performed on the building exhaust points if the process is inside an enclosure.

ii. At emission points where visible emissions are observed, the owner or operator shall initiate corrective action within eight hours of the initial observation. If correction actions are taken then a follow-up visible emission survey shall be made. If the visible emissions persist, the owner or operator shall perform or cause to be performed a Method 9, in accordance with 40 CFR Part 60, Appendix A, 24 hours of the initial observation.

iii. The owner or operator shall maintain records, monthly, of the results of all visible emissions surveys and tests. Records of the results of any visible emissions survey shall include the date of the survey, the name of the person conducting the survey, whether or not visible emissions were observed, and what if any corrective action was performed. If an emission point is not being operated during a given month, then no visible emission survey needs to be performed and a negative declaration shall be entered in the record.

S3. **Reporting** (Regulation 2.16, section 4.1.9.3)

The owner or operator shall submit quarterly compliance reports that include the information in this section.

a. **PM**

The owner or operator shall report the following information regarding PM By-Pass Activity in the quarterly compliance reports.

1) Number of times the PM vent stream by-passes the bin vent filters and is vented to the atmosphere;
2) Duration of each by-pass to the atmosphere;
3) Calculated pound per hour PM emissions for each by-pass; or

4) A negative declaration if no by-passes occurred.

b. **Opacity**

The owner or operator shall identify all periods of exceeding an opacity standard during a quarterly reporting period. The report shall include the following:

1) Any deviation from the requirement to perform daily (or monthly, if required) visible emission surveys or Method 9 tests;
2) Any deviation from the requirement to record the results of each VE survey and Method 9 test performed;
3) The date and time of each VE Survey where visible emissions were observed and the results of any Method 9 test performed;
4) The date, time and results of follow-up VE survey;
5) The date, time, and results of any Method 9 test performed;
6) Identification of all periods of exceeding an opacity standard; and
7) If no deviations occur during a quarterly reporting period, the report shall contain a negative declaration.

Emission Unit U18: Flyash storage silos

U18 Applicable Regulations:

FEDERALLY ENFORCEABLE REGULATIONS		
Regulation	**Title**	**Applicable Sections**
7.08	Standards of Performance for New Affected Facilities	1, 2, 3, 4, 5, 6

DISTRICT ONLY ENFORCEABLE REGULATIONS		
Regulation	**Title**	**Applicable Sections**
5.00	Definitions	1, 2
5.01	General Provisions	1 through 2
5.20	Methodology for Determining Benchmark Ambient Concentration of a Toxic Air Contaminant	1 through 6
5.21	Environmental Acceptability for Toxic Air Contaminants	1 through 5
5.22	Procedures for Determining the Maximum Ambient Concentration of a Toxic Air Contaminant	1 through 5
5.23	Categories of Toxic Air Contaminants	1 through 6

U18 Equipment:[111]

Emission Point	Description	Applicable Regulation	Control ID	Stack ID
E42	One (1) or more flyash silo for PJFF units, make Marietta Silos, model Concrete Field Erected, storage capacity 3,620 tons, maximum loading rate 79.5 ton/hr, equipped with bin vent filter.	5.00, 5.01, 5.20, 5.21, 5.22, 5.23, 7.08	C34	S37

U18 Control Devices:

ID	Description	Performance Indicator	Stack ID
C34	One (1) or more bin vent filters each controlling a flyash storage silo	N/A[112]	S37

[111] This unit was previously permitted under construction permit 34658-12-C.

[112] The bin vent filter equipped for each silo is considered as an integrated component of the silo. However, there are monitoring, record keeping and reporting requirements associated with any times that the filters are not in place and the process is operated.

U18 Specific Conditions

S1. **Standards** (Regulation 2.16, section 4.1.1)

a. **PM**

i. The owner or operator shall not allow PM emissions from emission point E42 to exceed 13.9 lbs/hr based on actual operating hours in a calendar day. (Regulation 7.08, section 3.3)

ii. The owner or operator shall maintain the bin vent filters in place at all times the process equipment is in operation, including periods of startup, shutdown, and malfunction, in a manner consistent with good air pollution control practice to meet the standards. (Regulation 2.16, section 4.1.1)

b. **Opacity**

The owner or operator shall not allow visible emissions to equal or exceed 20% opacity. (Regulation 7.08, section 3.1.1)

c. **TAC**

i. The owner or operator shall not allow Arsenic (As) emissions to exceed de minimis from this unit.[113] (Regulation 5.21, section 4.2 and section 4.3)

ii. See Plantwide Requirements S1.b.[114,115]

S2. **Monitoring and Record Keeping** (Regulation 2.16, sections 4.1.9.1 and 4.1.9.2)

The owner or operator shall maintain the required records for a minimum of 5 years and make the records readily available to the District upon request.

a. **PM**

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[113] Using 99.5% control efficiency and the TAC contents are based on previous sample analysis, all TACs are below the de minimis threshold levels. However, results of sample analysis vary from each other and the potential emission for Arsenic is close to its de minimis threshold. The source is required to conduct periodically sample analysis and demonstrate that the Arsenic emission is under de minimis level based on the most recent sampling results.

[114] LG&E submitted their TAC Environmental Acceptability Demonstration to the District on December 28, 2006, March 25, 2008, and April 9, 2010, in which the source has demonstrated compliance with the EA Goals. The proposed project for installation and modification of the bin vent filters will reduce TAC emissions plantwide. There will be no new TACs introduced at the facility, though more flyash will be collected and transferred to flyash transfer bins (U9) and silos (U8 and U18).The company demonstrated compliance with the STAR Program in the updated the EA Demonstration dated April 3, 2012.

[115] In the STAR EA Demonstration dated April 3, 2012, a control efficiency of 99.5% was used for bin vent filters controlling flyash silos and flyash transfer bins. LG&E has submitted a manufacturer's guarantee, which guarantees a 99.9% control efficiency for the fabric filters, on 9/13/2013.

i. The owner or operator shall maintain monthly records of the type and amount of material throughput for each piece of equipment.

ii. The owner or operator shall monthly perform a visual inspection of the structural and mechanical integrity of the bin vent filters for signs of damage, air leakage, corrosion, or other equipment defects, and repair and/or replace defective components as needed. The owner or operator shall maintain monthly records of the results.

iii. The owner or operator shall maintain daily records of any periods of time where the process was operating and the bin vent filters were not in place or a declaration that the bin vent filters were in place at all times that day when the process was operating.

iv. If there is any time that the bin vent filters are not in place when the process is operating, then the owner or operator shall keep a record of the following for each bypass event:

1) Date;
2) Start time and stop time;
3) Identification of the bin vent filters and process equipment;
4) PM emissions during the bypass in lb/hr;
5) Summary of the cause or reason for each bypass event;
6) Corrective action taken to minimize the extent or duration of the bypass event; and
7) Measures implemented to prevent reoccurrence of the situation that resulted in the bypass event.

b. **Opacity**

i. The owner or operator shall conduct a monthly one-minute visible emissions survey, during normal operation, of the emission points. No more than four emission points shall be observed simultaneously. The opacity surveys can be performed on the building exhaust points if the process is inside an enclosure.

ii. At emission points where visible emissions are observed, the owner or operator shall initiate corrective action within eight hours of the initial observation. If correction actions are taken then a follow-up visible emission survey shall be made. If the visible emissions persist, the owner or operator shall perform or cause to be performed a Method 9, in accordance with 40 CFR Part 60, Appendix A, 24 hours of the initial observation.

iii. The owner or operator shall maintain records, monthly, of the results of all visible emissions surveys and tests. Records of the results of any visible emissions survey shall include the date of the survey, the name of the person conducting the survey, whether or not visible emissions were observed, and what if any corrective action was performed. If an emission point is not being operated during a given month, then no visible emission survey needs to be performed and a negative declaration shall be entered in the record.

c. **TAC**

i. The owner or operator shall perform sampling and lab analysis for the flyash in order to determine the TAC concentrations, at least once every six months.

ii. The owner or operator shall calculate the TAC emissions at least once every six months. The average TAC concentrations of all sampling results during the previous 12 months combined with the sampling results from the current semiannual period shall be used for emission calculations.

iii. See Plantwide Requirements S2.b.

S3. **Reporting** (Regulation 2.16, section 4.1.9.3)

The owner or operator shall submit quarterly compliance reports that include the information in this section.

a. **PM**

The owner or operator shall report the following information regarding PM By-Pass Activity in the quarterly compliance reports.

1) Number of times the PM vent stream by-passes the bin vent filters and is vented to the atmosphere;
2) Duration of each by-pass to the atmosphere;
3) Calculated pound per hour PM emissions for each by-pass; or
4) A negative declaration if no by-passes occurred.

b. **Opacity**

The owner or operator shall identify all periods of exceeding an opacity standard during a quarterly reporting period. The report shall include the following:

1) Any deviation from the requirement to perform daily (or monthly, if required) visible emission surveys or Method 9 tests;
2) Any deviation from the requirement to record the results of each VE survey and Method 9 test performed;
3) The date and time of each VE Survey where visible emissions were observed and the results of any Method 9 test performed;

4) The date, time and results of follow-up VE survey;
5) The date, time, and results of any Method 9 test performed;
6) Identification of all periods of exceeding an opacity standard; and
7) If no deviations occur during a quarterly reporting period, the report shall contain a negative declaration.

c. **TAC**

See Plantwide Requirements S2.b.

Emission Unit U20: Gypsum pelletizing plant

U20 Applicable Regulations:

FEDERALLY ENFORCEABLE REGULATIONS		
Regulation	**Title**	**Applicable Sections**
7.06	Standards of Performance for New Indirect Heat Exchangers	1, 2, 3, 4, 5, 6, 7, 8
7.08	Standards of Performance for New Affected Facilities	1, 2, 3, 4, 5, 6
40 CFR 63 Subpart DDDDD	National Emission Standards for Hazardous Air Pollutant for Industrial, Commercial, and Institutional Boilers and Process Heaters	63.7480 – 63.7575

DISTRICT ONLY ENFORCEABLE REGULATIONS		
Regulation	**Title**	**Applicable Sections**
5.00	Definitions	1, 2
5.01	General Provisions	1 through 2
5.02	Adoption of National Emission Standards for Hazardous Air Pollutants	1, 3.95 and 4
5.14	Hazardous Air Pollutants and Source Categories	1, 2
5.20	Methodology for Determining Benchmark Ambient Concentration of a Toxic Air Contaminant	1 through 6
5.21	Environmental Acceptability for Toxic Air Contaminants	1 through 5
5.22	Procedures for Determining the Maximum Ambient Concentration of a Toxic Air Contaminant	1 through 5
5.23	Categories of Toxic Air Contaminants	1 through 6

U20 Equipment:[116,117]

Emission Point	Description	Applicable Regulation	Control ID	Stack ID
E44-a	One (1) load hopper used for gypsum receiving, capacity 50 ton/hr.	7.08	C36	S39
E44-b	One (1) conveyor (hopper to dispersion dryer)	7.08	C36	S39

[116] This unit was previously permitted under permit 35668-12-C and 35673-12-C. Limestone silo (E44-o) is added upon review of the construction application dated July 10, 2013.

[117] Per Regulation 5.01, section 1.6.7, the TAC emissions from the combustion of natural gas are considered to be "de minimis emissions" for the STAR Program. The other equipment for this unit is not subject to STAR since it does not have any TAC emissions.

Emission Point	Description	Applicable Regulation	Control ID	Stack ID
E44-c	One (1) Allgaier dispersion dryer	7.08	N/A	N/A
E44-d	One (1) pneumatic conveyor with a cyclone separator (baghouse to mixer load hopper)	7.08	N/A	N/A
E44-e	One (1) mixer load hopper, capacity 50 ton/hr	7.08	N/A	N/A
E44-f	One (1) rotary airlock conveyor (mixer load hopper to pin mixer)	7.08	N/A	N/A
E44-g	One (1) Pin or Plow mixer with a Lingo sulfonate storage tank	7.08	N/A	N/A
E44-h	One (1) belt conveyor (pin mixer to Disc pelletizer)	7.08	N/A	N/A
E44-i	one (1) DISC pelletizer	7.08	N/A	N/A
E44-j	One (1) belt conveyor (Disc pelletizer to fluid bed dryer)	7.08	N/A	N/A
E44-k	One (1) Allgaier vibrating fluid bed dryer	7.08	N/A	N/A
E44-l	One (1) Mogensen sizer/screener	7.08	N/A	N/A
E44-m	One (1) belt conveyor (screener to product pile)	7.08	N/A	N/A
E44-n	One (1) hammer mill	7.08	N/A	N/A
E44-o	One (1) limestone silo	7.08	N/A	N/A
E44-p	One (1) de-dust system, consists of: one (1) 15,000 gal storage, one (1) 35 tph conveyor (make: Layco), one (1) 20 tph batch mixer, one (1) 20 tph surge hopper (make: Charah), two (2) 35 tph bucket elevators (#1 and #2), make TBD, two (2) 35 tph batch hopper (#1 and #2), make TBD, and one (1) 35 tph discharge conveyor, make TBD[118]	7.08	N/A	N/A
E45 and E46	Two (2) natural gas-fired heaters used for dispersion dryer and fluid bed dryer respectively, combined heat input rate 42 MMBtu/hr, make Star Combustion [119]	5.00, 5.01, 5.02, 5.14, 5.20, 5.21, 5.22, 5.23, 7.06, 40 CFR 63 Subpart DDDDD	N/A	S40 and S41

[118] Construction application for the de-dust system was received on July 29, 2015. It was determined this equipment is an insignificant activity per PTE. Therefore no construction permit was required.

[119] LG&E Mill Creek Station is a major source of HAP. Therefore the heater is subject to the major source Boiler MACT, 40 CFR 63 Subpart DDDDD. This unit is not subject to 40 CFR 60, Subpart Dc – Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units, since the heater does not generate steam.

U20 Control Devices:

ID	Description	Performance Indicator	Stack ID
C36	One (1) baghouse used as gypsum separator and PM control, make Donaldson Torit, model DuraLife [120]	N/A	S39

[120] LG&E submitted the parameter range for normal operation of the dust collector on August 29, 2013.

U20 Specific Conditions

S1. **Standards** (Regulation 2.16, section 4.1.1)

a. **PM**

i. The owner or operator shall not allow PM emissions from the gypsum pelletizing process (E44) to exceed 32.4 lbs/hr based on actual operating hours in a calendar day.[121] (Regulation 7.08, section 3.3)

ii. The owner or operator shall not allow PM emissions from each natural gas-fired heater (E45, E46) to exceed 0.10 lb/MMBtu actual total heat input.[122] (Regulation 7.06, section 4.1.2)

b. **Opacity**

i. The owner or operator shall not allow visible emissions from the gypsum pelletizing process (E44) to equal or exceed 20% opacity. (Regulation 7.08, section 3.1.1)

ii. The owner or operator combusting natural gas (E45 and E46) shall not cause to be discharged into the atmosphere from any affected facility PM emissions which exhibit greater than 20% opacity.[123] (Regulation 7.06, section 4.2)

c. **SO_2**

The owner or operator shall not cause to be discharged into the atmosphere from each natural gas-fired heater (E45, E46) any gases which contain SO_2 in excess of 0.8 lb/MMBtu actual total heat input.[122] (Regulation 7.06, section 5.1.2)

d. **HAP** (40 CFR 63, Subpart DDDDD. For E45 and E46 heaters only)

Work Practice Standard:

The owner or operator shall conduct a tune-up of the process heaters annually as specified in 40 CFR 63.7540. (40 CFR 63.7500(a) and Table 3)

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[121] A one-time PM compliance demonstration has been performed for this equipment and the lb/hr standard cannot be exceeded uncontrolled.

[122] A one-time PM and SO2 compliance demonstration has been performed for the heater, using AP-42 emission factors and combusting natural gas, and the emission standards under Regulation 7.06 for PM and SO2 cannot be exceeded when combusting natural gas.

[123] It has been determined that using a natural gas fired heater will inherently meet the 20% opacity standard. Therefore, the company is not required to perform periodic monitoring to demonstrate compliance with the opacity standard when combusting natural gas.

S2. **Monitoring and Record Keeping** (Regulation 2.16, sections 4.1.9.1 and 4.1.9.2)

The owner or operator shall maintain the required records for a minimum of 5 years and make the records readily available to the District upon request.

a. **PM**

There are no routine monitoring or record keeping requirements for this pollutant.

b. **Opacity**

For the gypsum pelletizing process (E44):

i. The owner or operator shall conduct a monthly one-minute visible emissions survey, during normal operation, of the emission points. No more than four emission points shall be observed simultaneously. The opacity surveys can be performed on the building exhaust points if the process is inside an enclosure.

ii. At emission points where visible emissions are observed, the owner or operator shall initiate corrective action within eight hours of the initial observation. If correction actions are taken then a follow-up visible emission survey shall be made. If the visible emissions persist, the owner or operator shall perform or cause to be performed a Method 9, in accordance with 40 CFR Part 60, Appendix A, within 24 hours of the initial observation.

iii. The owner or operator shall maintain records, monthly, of the results of all visible emissions surveys and tests. Records of the results of any visible emissions survey shall include the date of the survey, the name of the person conducting the survey, whether or not visible emissions were observed, and what if any corrective action was performed. If an emission point is not being operated during a given month, then no visible emission survey needs to be performed and a negative declaration shall be entered in the record.

For the natural gas-fired heaters (E45 and E46):

iv. There are no routine monitoring or record keeping requirements for this equipment.

c. **SO_2**

For the natural gas-fired heaters (E45 and E46):

There are no monitoring and record keeping requirements for this equipment.

d. **HAP** (40 CFR 63, Subpart DDDDD. For E45 and E46 heaters only)

For all tune-ups, the owner or operator shall keep records of the dates and procedures of each tune-up, and the fuel used. The owner or operator should begin keeping fuel records for at least 12 months prior to the scheduled tune-up. The record must be kept on-site and submitted to the delegated authority if requested. (40 CFR 63.7555(a))

S3. **Reporting** (Regulation 2.16, section 4.1.9.3)

a. **PM**

There are no routine reporting requirements for this pollutant.

b. **Opacity**

For the gypsum pelletizing process (E44):

i. The owner or operator shall identify all periods of exceeding an opacity standard during a semi-annual reporting period. The report shall include the following:

1) Any deviation from the requirement to perform daily (or monthly, if required) visible emission surveys or Method 9 tests;
2) Any deviation from the requirement to record the results of each VE survey and Method 9 test performed;
3) The date and time of each VE Survey where visible emissions were observed and the results of any Method 9 test performed;
4) The date, time and results of any follow-up VE survey;
5) The date, time, and results of any Method 9 test performed;
6) Identification of all periods of exceeding an opacity standard; and
7) If no deviations occur during a semi-annual reporting period, the report shall contain a negative declaration.

For the natural gas-fired heaters (E45 and E46):

ii. There are no routine reporting requirements for this equipment.

c. **SO_2**

For the natural gas-fired heaters (E45 and E46):

There are no routine reporting requirements for this equipment.

d. **HAP** (40 CFR 63, Subpart DDDDD. For E45 and E46 heaters only)

Initial notification:

i. If the heaters are startup before January 31, 2013, the owner or operator shall submit an Initial Notification not later than 120 days after January 31, 2013. (40 CFR 63.7545(b))

ii. If the heaters are startup after January 31, 2013, the owner or operator shall submit an Initial Notification not later than 15 days after the actual date of startup of the affected source.[124] (40 CFR 63.7545(c))

iii. For initial tune-up, the owner or operator shall submit a signed statement in the Initial Notification that indicates that the owner or operator conducted an initial tune-up of the boiler. For subsequent annual tune-ups, the owner or operator may submit only an annual compliance report. (40 CFR 63.7550(b))

[124] On October 15, 2014, LG&E submitted an initial notification for process heaters E45 and E46.

Emission Unit U21: Coal handling facilities

U21 Applicable Regulations:

FEDERALLY ENFORCEABLE REGULATIONS		
Regulation	**Title**	**Applicable Sections**
6.09	Standards of Performance for Existing Process Operations	1, 2, 3, 4, 5
7.08	Standards of Performance for New Process Operations	1, 2, 3, 4
40 CFR 60, Subpart Y	Standards of Performance for Coal Preparation Plants	60.250, 60.251, 60.254, 60.255, 60.256, 60.257, 60.258

DISTRICT ONLY ENFORCEABLE REGULATIONS		
Regulation	**Title**	**Applicable Sections**
5.00	Definitions	1, 2
5.01	General Provisions	1 through 2
5.20	Methodology for Determining Benchmark Ambient Concentration of a Toxic Air Contaminant	1 through 6
5.21	Environmental Acceptability for Toxic Air Contaminants	1 through 5
5.22	Procedures for Determining the Maximum Ambient Concentration of a Toxic Air Contaminant	1 through 5
5.23	Categories of Toxic Air Contaminants	1 through 6
7.02	Federal New Source Performance Standards Incorporated by Reference	1.1, 1.38, 2, 3, 4, 5

U21 Equipment:

Emission Point	Description	Applicable Regulation	Control ID	Stack ID
E47-a	One (1) barge unloading operation, rated capacity 1,500 tons/hr (1980)	5.00, 5.01, 5.20, 5.21, 5.22, 5.23, 7.02, 7.08, 40 CFR 60, Subpart Y	N/A	N/A
E47-b	One (1) railcar unloading, rated capacity 2,400 tons/hr (1971)	5.00, 5.01, 5.02, 5.14, 5.20, 5.21, 5.22, 5.23, 6.09	N/A	N/A
E47-c	One (1) coal radial stacker, rated capacity 1,500 tons/hr (1971)		N/A	N/A

Emission Point	Description	Applicable Regulation	Control ID	Stack ID
E47-d	Two (2) coal crushers, rated capacity 900 tons/hr for each (2014)	5.00, 5.01, 5.02, 5.14, 5.20, 5.21, 5.22, 5.23, 7.08, 40 CFR 60, Subpart Y	N/A	N/A
E47-e1 through E47-e16	Sixteen (16) coal belt conveyors, rated capacity 750 tons/hr for 40" belt conveyors and 2,400 tons/hr for 60" belt conveyor (1971)	5.00, 5.01, 5.02, 5.14, 5.20, 5.21, 5.22, 5.23, 6.09	N/A	N/A
E47-f	One (1) coal storage pile (drop point emission) (1971)		N/A	N/A
E47-g	One (1) fuel additive facility used to supply fuel additives to coal to reduce NOx and mercury emissions, consisting of: Two (2) silo for solid additive M45-PC A1 and M45-PC A2, make Tank Connection. One (1) feed hopper, make TBD. One (1) mix tank, make TBD. One (1) propane heater, make Hubbel, capacity 0.25 MMBtu/hr.[125]	7.08	N/A	N/A

U21 Control Devices:

There is no control device associated with this unit.

[125] Construction application for the fuel additive facility was received on August 19, 2015. It was determined this equipment is an insignificant activity per PTE. Therefore no construction permit was required.

U21 Specific Conditions

S1. **Standards** (Regulation 2.16, section 4.1.1)

a. **PM**

i. The owner or operator shall not allow PM emissions to exceed 55.8 lb/hr from barge unloading (E47a) based on actual operating hours in a calendar day.[126] (Regulation 7.08, section 3.1.2)

ii. The owner or operator shall not allow PM emissions to exceed 89.5 lb/hr from railcar unloading (E47b) based on actual operating hours in a calendar day.[126] (Regulation 6.09, section 3.2)

iii. The owner or operator shall not allow PM emissions to exceed 83.0 lb/hr from radial stacker (E47c) based on actual operating hours in a calendar day.[126] (Regulation 6.09, section 3.2)

iv. The owner or operator shall not allow PM emissions to exceed 51.4 lb/hr from each crusher (E47d) based on actual operating hours in a calendar day.[126] (Regulation 7.08, section 3.1.2)

v. The owner or operator shall not allow PM emissions to exceed 73.9 lb/hr from each of the 40" belt conveyors and 89.5 lb/hr from each of the 60" belt conveyors (E47e) based on actual operating hours in a calendar day.[126] (Regulation 6.09, section 3.2)

vi. The owner or operator shall not allow PM emissions to exceed 89.5 lb/hr from coal pile drop point (E47f) based on actual operating hours in a calendar day.[126] (Regulation 6.09, section 3.2)

b. **Opacity**

The owner or operator shall not allow visible emissions to equal or exceed 20% opacity. (Regulation 6.09, section 3.1) (Regulation 7.08, section 3.1.1)

c. **Standards of Performance for Coal Preparation and Processing Plants** (40 CFR 60, Subpart Y)

i. For emission point E47a (barge unloading):

The owner or operator shall not allow visible emissions to equal or exceed 20% opacity. (40 CFR 60.254(a))

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[126] It has been demonstrated that the PM emissions cannot exceed the PM standards specified in Regulation 6.09 uncontrolled. Therefore there are no monitoring, record keeping, and reporting requirements with respect to the PM lb/hr emission standards.

ii. For emission point E47d (new crushers):

1) The owner or operator shall not allow visible emissions to equal or exceed 10% opacity. (40 CFR 60.254(b)(1))

2) The owner or operator must not cause to be discharged into the atmosphere from any mechanical vent on an affected facility gases which contain particulate matter in excess of 0.023 g/dscm (0.010 gr/dscf). (40 CFR 60.254(b)(2))

d. **TAC**

See Plantwide Requirements S1.b.[127]

S2. **Monitoring and Record Keeping** (Regulation 2.16, sections 4.1.9.1 and 4.1.9.2)

The owner or operator shall maintain the required records for a minimum of 5 years and make the records readily available to the District upon request.

a. **PM**

The owner or operator shall keep monthly records of the throughput of coal for each emission point.

b. **Opacity**

i. The owner or operator shall conduct a monthly one-minute visible emissions survey, during normal operation, of the emission points. No more than four emission points shall be observed simultaneously. The opacity surveys can be performed on the building exhaust points if the process is inside an enclosure.

ii. At emission points where visible emissions are observed, the owner or operator shall initiate corrective action within eight hours of the initial observation. If the visible emissions persist, the owner or operator shall perform or cause to be performed a Method 9, in accordance with 40 CFR Part 60, Appendix A, within 24 hours of the initial observation.

iii. The owner or operator shall maintain records, monthly, of the results of all visible emissions surveys and tests. Records of the results of any visible emissions survey shall include the date of the survey, the name of the person conducting the survey, whether or not visible emissions were observed, and what if any corrective action was performed. If an emission point is not

[127] Each TAC contained in coal is less than 0.1% by weight. According to Regulation 5.21, section 2.1, emissions of TACs from this coal handling operation are de minimis.

being operated during a given month, then no visible emission survey needs to be performed and a negative declaration shall be entered in the record.

c. **Standards of Performance for Coal Preparation and Processing Plants** (40 CFR 60, Subpart Y)

i. Performance tests and other compliance requirements (40 CFR 60.255)

1) An owner or operator of each affected facility that commenced construction, reconstruction, or modification on or before April 28, 2008, must conduct all performance tests required by 40 CFR 60.8 to demonstrate compliance with the applicable emission standards using the methods identified in 40 CFR 60.257. (40 CFR 60.255(a))

2) An owner or operator of each affected facility that commenced construction, reconstruction, or modification after April 28, 2008, must conduct performance tests according to the requirements of40 CFR 60.8 and the methods identified in 40 CFR 60.257 to demonstrate compliance with the applicable emissions standards in this subpart as specified in paragraphs (b)(1) and (2) of this section. (40 CFR 60.255(b))

(a) For each affected facility subject to a PM, SO_2, or combined NO_X and CO emissions standard, an initial performance test must be performed. Thereafter, a new performance test must be conducted according the requirements in paragraphs (b)(1)(i) through (iii) of this section, as applicable. (40 CFR 60.255(b)(1))

(i) If the results of the most recent performance test demonstrate that emissions from the affected facility are greater than 50 percent of the applicable emissions standard, a new performance test must be conducted within 12 calendar months of the date that the previous performance test was required to be completed. (40 CFR 60.255(b)(1)(i))

(ii) If the results of the most recent performance test demonstrate that emissions from the affected facility are 50 percent or less of the applicable emissions standard, a new performance test must be conducted within 24 calendar months of the date that the previous performance test was required to be completed. (40 CFR 60.255(b)(1)(ii))

(iii) An owner or operator of an affected facility that has not operated for the 60 calendar days prior to the due date of a performance test is not required to perform the subsequent performance test until 30 calendar days after the next operating day.(40 CFR 60.255(b)(1)(iii))

(b) For each affected facility subject to an opacity standard, an initial performance test must be performed. Thereafter, a new performance test must be conducted according to the requirements in paragraphs (b)(2)(i) through (iii) of this section, as applicable, except as provided for in paragraphs (e) and (f) of this section. Performance test and other compliance requirements for coal truck dump operations are specified in paragraph (h) of this section. (40 CFR 60.255(b)(2))

(i) If any 6-minute average opacity reading in the most recent performance test exceeds half the applicable opacity limit, a new performance test must be conducted within 90 operating days of the date that the previous performance test was required to be completed. (40 CFR 60.255(b)(2)(i))

(ii) If all 6-minute average opacity readings in the most recent performance test are equal to or less than half the applicable opacity limit, a new performance test must be conducted within 12 calendar months of the date that the previous performance test was required to be completed. (40 CFR 60.255(b)(2)(ii))

(iii) An owner or operator of an affected facility continuously monitoring scrubber parameters as specified in 40 CFR 60.256(b)(2) is exempt from the requirements in paragraphs (b)(2)(i) and (ii) if opacity performance tests are conducted concurrently with (or within a 60-minute period of) PM performance tests. (40 CFR 60.255(b)(2)(iii))

3) If any affected coal processing and conveying equipment (e.g., breakers, crushers, screens, conveying systems), coal storage systems, or coal transfer and loading systems that commenced construction, reconstruction, or modification after April 28, 2008, are enclosed in a building, and emissions from the building do not exceed any of the standards in 40 CFR 60.254 that apply to the affected facility, then the facility shall be deemed to be in compliance with such standards. (40 CFR 60.255(c))

4) An owner or operator of an affected facility (other than a thermal dryer) that commenced construction, reconstruction, or modification after April 28, 2008, is subject to a PM emission standard and uses a control device with a design controlled potential PM emissions rate of 1.0 Mg (1.1 tons) per year or less is exempted from the requirements of paragraphs (b)(1)(i) and (ii) of this section provided that the owner or operator meets all of the conditions specified in paragraphs (d)(1) through (3) of this section. This exemption does not apply to thermal dryers. (40 CFR 60.255(d))

(a) PM emissions, as determined by the most recent performance test, are less than or equal to the applicable limit, (40 CFR 60.255(d)(1))

(b) The control device manufacturer's recommended maintenance procedures are followed, and (40 CFR 60.255(d)(2))

(c) All 6-minute average opacity readings from the most recent performance test are equal to or less than half the applicable opacity limit or the monitoring requirements in paragraphs (e) or (f) of this section are followed. (40 CFR 60.255(d)(3))

5) For an owner or operator of a group of up to five of the same type of affected facilities that commenced construction, reconstruction, or modification after April 28, 2008, that are subject to PM emissions standards and use identical control devices, the Administrator or delegated authority may allow the owner or operator to use a single PM performance test for one of the affected control devices to demonstrate that the group of affected facilities is in compliance with the applicable emissions standards provided that the owner or operator meets all of the conditions specified in paragraphs (e)(1) through (3) of this section. (40 CFR 60.255(e))

(a) PM emissions from the most recent performance test for each individual affected facility are 90 percent or less of the applicable PM standard; (40 CFR 60.255(e)(1))

(b) The manufacturer's recommended maintenance procedures are followed for each control device; and (40 CFR 60.255(e)(2))

(c) A performance test is conducted on each affected facility at least once every 5 calendar years. (40 CFR 60.255(e)(3))

6) As an alternative to meeting the requirements in paragraph (b)(2) of this section, an owner or operator of an affected facility that commenced construction, reconstruction, or modification after April 28, 2008, may elect to comply with the requirements in paragraph (f)(1) or (f)(2) of this section. (40 CFR 60.255(f))

(a) Monitor visible emissions from each affected facility according to the requirements in paragraphs (f)(1)(i) through (iii) of this section. (40 CFR 60.255(f)(1))

(i) Conduct one daily 15-second observation each operating day for each affected facility (during normal operation) when the coal preparation and processing plant is in operation. Each observation must be recorded as either visible emissions observed or no visible emissions observed. Each observer determining the presence of visible emissions must meet the training requirements specified in 40 CFR 2.3 of Method 22 of appendix A-7 of this part. If visible emissions are observed during any 15-second observation, the owner or operator must adjust the operation of the affected facility and demonstrate within 24 hours that no visible emissions are observed from the affected facility. If visible emissions are observed, a Method 9, of appendix A- 4 of this part, performance test must be conducted within 45 operating days. (40 CFR 60.255(f)(1)(i))

(ii) Conduct monthly visual observations of all process and control equipment. If any deficiencies are observed, the necessary maintenance must be performed as expeditiously as possible. (40 CFR 60.255(f)(1)(ii))

(iii) Conduct a performance test using Method 9 of appendix A-4 of this part at least once every 5 calendar years for each affected facility. (40 CFR 60.255(f)(1)(iii))

(b) Prepare a written site-specific monitoring plan for a digital opacity compliance system for approval by the Administrator or delegated authority. The plan shall require observations of at least one digital image every 15 seconds for 10-minute periods (during normal operation) every operating day. An approvable monitoring plan must include a demonstration that the occurrences of visible emissions are not in excess of 5 percent of the observation period. For reference purposes in preparing the monitoring plan, see OAQPS "Determination of Visible Emission Opacity from Stationary Sources Using Computer-Based Photographic Analysis Systems." This document is available from the U.S. Environmental Protection Agency (U.S. EPA); Office of Air Quality and Planning Standards; Sector Policies and Programs Division; Measurement Group (D243-02), Research Triangle Park, NC 27711. This document is also available on the Technology Transfer Network (TTN) under Emission Measurement Center Preliminary Methods. The monitoring plan approved by the Administrator or delegated authority shall be implemented by the owner or operator. (40 CFR 60.255(f)(2))

7) As an alternative to meeting the requirements in paragraph (b)(2) of this section, an owner or operator of an affected facility that commenced construction, reconstruction, or modification after April 28, 2008, subject to a visible emissions standard under this subpart may install, operate, and maintain a continuous opacity monitoring system (COMS). Each COMS used to comply with provisions of this subpart must be installed, calibrated, maintained, and continuously operated according to the requirements in paragraphs (g)(1) and (2) of this section. (40 CFR 60.255(g))

(a) The COMS must meet Performance Specification 1 in 40 CFR part 60, appendix B. (40 CFR 60.255(g)(1))

(b) The COMS must comply with the quality assurance requirements in paragraphs (g)(2)(i) through (v) of this section. (40 CFR 60.255(g)(2))

(i) The owner or operator must automatically (intrinsic to the opacity monitor) check the zero and upscale (span) calibration drifts at least once daily. For particular COMS, the acceptable range of zero and upscale calibration materials is as defined in the applicable version of Performance Specification 1 in 40 CFR part 60, appendix B. (40 CFR 60.255(g)(2)(i))

(ii) The owner or operator must adjust the zero and span whenever the 24-hour zero drift or 24-hour span drift exceeds 4 percent opacity. The COMS must allow for the amount of excess zero and span drift measured at the 24-hour interval checks to be recorded and quantified. The optical surfaces exposed to the effluent gases must be cleaned prior to performing the zero and span drift adjustments, except for systems using automatic zero adjustments. For systems using automatic zero adjustments, the optical surfaces must be cleaned when the cumulative automatic zero compensation exceeds 4 percent opacity. (40 CFR 60.255(g)(2)(ii))

(iii) The owner or operator must apply a method for producing a simulated zero opacity condition and an upscale (span) opacity condition using a certified neutral density filter or other related technique to produce a known obscuration of the light beam. All procedures applied must provide a system check of the analyzer internal optical surfaces and all electronic circuitry including the lamp and photodetector assembly. (40 CFR 60.255(g)(2)(iii))

(iv) Except during periods of system breakdowns, repairs, calibration checks, and zero and span adjustments, the COMS must be in continuous operation and must complete a minimum of one cycle of sampling and analyzing for each successive 10-second period and one cycle of data recording for each successive 6-minute period. (40 CFR 60.255(g)(2)(iv))

(v) The owner or operator must reduce all data from the COMS to 6- minute averages. Six-minute opacity averages must be calculated from 36 or more data points equally spaced over each 6-minute period. Data recorded during periods of system breakdowns, repairs, calibration checks, and zero and span adjustments must not be included in the data averages. An arithmetic or integrated average of all data may be used. (40 CFR 60.255(g)(2)(v))

ii. Continuous monitoring requirements (if applicable) (40 CFR 60.256)

1) The owner or operator of each affected facility constructed, reconstructed, or modified after April 28, 2008, that has one or more mechanical vents must install, calibrate, maintain, and continuously operate the monitoring devices specified in paragraphs (b)(1)

through (3) of this section, as applicable to the mechanical vent and any control device installed on the vent. (40 CFR 60.256(b))

(a) For mechanical vents with fabric filters (baghouses) with design controlled potential PM emissions rates of 25 Mg (28 tons) per year or more, a bag leak detection system according to the requirements in paragraph (c) of this section. (40 CFR 60.256(b)(1))

(b) For mechanical vents with wet scrubbers, monitoring devices according to the requirements in paragraphs (b)(2)(i) through (iv) of this section. (40 CFR 60.256(b)(2))

(i) A monitoring device for the continuous measurement of the pressure loss through the venturi constriction of the control equipment. The monitoring device is to be certified by the manufacturer to be accurate within ± 1 inch water gauge. (40 CFR 60.256(b)(2)(i))

(ii) A monitoring device for the continuous measurement of the water supply flow rate to the control equipment. The monitoring device is to be certified by the manufacturer to be accurate within ± 5 percent of design water supply flow rate. (40 CFR 60.256(b)(2)(ii))

(iii) A monitoring device for the continuous measurement of the pH of the wet scrubber liquid. The monitoring device is to be certified by the manufacturer to be accurate within ± 5 percent of design pH. (40 CFR 60.256(b)(2)(iii))

(iv) An average value for each monitoring parameter must be determined during each performance test. Each monitoring parameter must then be maintained within 10 percent of the value established during the most recent performance test on an operating day average basis. (40 CFR 60.256(b)(2)(iv))

(c) For mechanical vents with control equipment other than wet scrubbers, a monitoring device for the continuous measurement of the reagent injection flow rate to the control equipment, as applicable. The monitoring device is to be certified by the manufacturer to be accurate within ± 5 percent of design injection flow rate. An average reagent injection flow rate value must be determined during each performance test. The reagent injection flow rate must then be maintained within 10 percent of the value established during the most recent performance test on an operating day average basis. (40 CFR 60.256(b)(3))

2) Each bag leak detection system used to comply with provisions of this subpart must be installed, calibrated, maintained, and continuously operated according to the requirements in paragraphs (c)(1) through (3) of this section. (40 CFR 60.256(c))

(a) The bag leak detection system must meet the specifications and requirements in paragraphs (c)(1)(i) through (viii) of this section. (40 CFR 60.256(c)(1))

(i) The bag leak detection system must be certified by the manufacturer to be capable of detecting PM emissions at concentrations of 1 milligram per dry standard cubic meter (mg/dscm) (0.00044 grains per actual cubic foot (gr/acf)) or less. (40 CFR 60.256(c)(1)(i))

(ii) The bag leak detection system sensor must provide output of relative PM loadings. The owner or operator shall continuously record the output from the bag leak detection system using electronic or other means (e.g., using a strip chart recorder or a data logger). (40 CFR 60.256(c)(1)(ii))

(iii) The bag leak detection system must be equipped with an alarm system that will sound when the system detects an increase in relative particulate loading over the alarm set point established according to paragraph (c)(1)(iv) of this section, and the alarm must be located such that it can be heard by the appropriate plant personnel. (40 CFR 60.256(c)(1)(iii))

(iv) In the initial adjustment of the bag leak detection system, the owner or operator must establish, at a minimum, the baseline output by adjusting the sensitivity (range) and the averaging period of the device, the alarm set points, and the alarm delay time. (40 CFR 60.256(c)(1)(iv))

(v) Following initial adjustment, the owner or operator must not adjust the averaging period, alarm set point, or alarm delay time without approval from the Administrator or delegated authority except as provided in paragraph (c)(2)(vi) of this section. (40 CFR 60.256(c)(1)(v))

(vi) Once per quarter, the owner or operator may adjust the sensitivity of the bag leak detection system to account for seasonal effects, including temperature and humidity, according to the procedures identified in the site-specific monitoring plan required by paragraph (c)(2) of this section. (40 CFR 60.256(c)(1)(vi))

(vii) The owner or operator must install the bag leak detection sensor downstream of the fabric filter. (40 CFR 60.256(c)(1)(vii))

(viii) Where multiple detectors are required, the system's instrumentation and alarm may be shared among detectors. (40 CFR 60.256(c)(1)(viii))

(b) The owner or operator must develop and submit to the Administrator or delegated authority for approval a site-specific monitoring plan for each bag leak detection system. This plan must be submitted to the Administrator or delegated authority 30 days prior to startup of the affected facility. The owner or operator must operate and maintain the bag leak detection system according to the site- specific monitoring plan at all times. Each monitoring plan must describe the items in paragraphs (c)(2)(i) through (vi) of this section. (40 CFR 60.256(c)(2))

(i) Installation of the bag leak detection system; (40 CFR 60.256(c)(2)(i))

(ii) Initial and periodic adjustment of the bag leak detection system, including how the alarm set-point will be established; (40 CFR 60.256(c)(2)(ii))

(iii) Operation of the bag leak detection system, including quality assurance procedures; (40 CFR 60.256(c)(2)(iii))

(iv) How the bag leak detection system will be maintained, including a routine maintenance schedule and spare parts inventory list; (40 CFR 60.256(c)(2)(iv))

(v) How the bag leak detection system output will be recorded and stored; and (40 CFR 60.256(c)(2)(v))

(vi) Corrective action procedures as specified in paragraph (c)(3) of this section. In approving the site-specific monitoring plan, the Administrator or delegated authority may allow the owner and operator more than 3 hours to alleviate a specific condition that causes an alarm if the owner or operator identifies in the monitoring plan this specific condition as one that could lead to an alarm, adequately explains why it is not feasible to alleviate this condition within 3 hours of the time the alarm occurs, and demonstrates that the requested time will ensure alleviation of this condition as expeditiously as practicable. (40 CFR 60.256(c)(2)(vi))

(c) For each bag leak detection system, the owner or operator must initiate procedures to determine the cause of every alarm within 1 hour of the alarm. Except as provided in paragraph (c)(2)(vi) of this section, the owner or operator must alleviate the cause of the alarm within 3 hours of the alarm by taking whatever corrective action(s) are necessary. Corrective actions may include, but are not limited to the following: (40 CFR 60.256(c)(3))

(i) Inspecting the fabric filter for air leaks, torn or broken bags or filter media, or any other condition that may cause an increase in PM emissions; (40 CFR 60.256(c)(3)(i))

(ii) Sealing off defective bags or filter media; (40 CFR 60.256(c)(3)(ii))

(iii) Replacing defective bags or filter media or otherwise repairing the control device; (40 CFR 60.256(c)(3)(iii))

(iv) Sealing off a defective fabric filter compartment; (40 CFR 60.256(c)(3)(iv))

(v) Cleaning the bag leak detection system probe or otherwise repairing the bag leak detection system; or

(40 CFR 60.256(c)(3)(v))

(vi) Shutting down the process producing the PM emissions. (40 CFR 60.256(c)(3)(vi))

iii. Test methods and procedures (if applicable) (40 CFR 60.257)

1) The owner or operator must determine compliance with the applicable opacity standards as specified in paragraphs (a)(1) through (3) of this section. (40 CFR 60.257(a))

(a) Method 9 of appendix A-4 of this part and the procedures in 40 CFR 60.11 must be used to determine opacity, with the exceptions specified in paragraphs (a)(1)(i) and (ii). (40 CFR 60.257(a)(1))

(i) The duration of the Method 9 of appendix A-4 of this part performance test shall be 1 hour (ten 6-minute averages). (40 CFR 60.257(a)(1)(i))

(ii) If, during the initial 30 minutes of the observation of a Method 9 of appendix A-4 of this part performance test, all of the 6- minute average opacity readings are less than or equal to half the applicable opacity limit, then the observation period may be reduced from 1 hour to 30 minutes. (40 CFR 60.257(a)(1)(ii))

(b) To determine opacity for fugitive coal dust emissions sources, the additional requirements specified in paragraphs (a)(2)(i) through (iii) must be used. (40 CFR 60.257(a)(2))

(i) The minimum distance between the observer and the emission source shall be 5.0 meters (16 feet), and the sun shall be oriented in the 140-degree sector of the back. (40 CFR 60.257(a)(2)(i))

(ii) The observer shall select a position that minimizes interference from other fugitive coal dust emissions sources and make observations such that the line of vision is approximately perpendicular to the plume and wind direction. (40 CFR 60.257(a)(2)(ii))

(iii) The observer shall make opacity observations at the point of greatest opacity in that portion of the plume where condensed water vapor is not present. Water vapor is not considered a visible emission. (40 CFR

60.257(a)(2)(iii))

(c) A visible emissions observer may conduct visible emission observations for up to three fugitive, stack, or vent emission points within a 15-second interval if the following conditions specified in paragraphs (a)(3)(i) through (iii) of this section are met. (40 CFR 60.257(a)(3))

(i) No more than three emissions points may be read concurrently. (40 CFR 60.257(a)(3)(i))

(ii) All three emissions points must be within a 70 degree viewing sector or angle in front of the observer such that the proper sun position can be maintained for all three points. (40 CFR 60.257(a)(3)(ii))

(iii) If an opacity reading for any one of the three emissions points is within 5 percent opacity from the applicable standard (excluding readings of zero opacity), then the observer must stop taking readings for the other two points and continue reading just that single point. (40 CFR 60.257(a)(3)(iii))

2) The owner or operator must conduct all performance tests required by 40 CFR 60.8 to demonstrate compliance with the applicable emissions standards specified in 40 CFR 60.252 according to the requirements in 40 CFR 60.8 using the applicable test methods and procedures in paragraphs (b)(1) through (8) of this section. (40 CFR 60.257(b))

(a) Method 1 or 1A of appendix A-4 of this part shall be used to select sampling port locations and the number of traverse points in each stack or duct. Sampling sites must be located at the outlet of the control device (or at the outlet of the emissions source if no control device is present) prior to any releases to the atmosphere. (40 CFR 60.257(b)(1))

(b) Method 2, 2A, 2C, 2D, 2F, or 2G of appendix A-4 of this part shall be used to determine the volumetric flow rate of the stack gas. (40 CFR 60.257(b)(2))

(c) Method 3, 3A, or 3B of appendix A-4 of this part shall be used to determine the dry molecular weight of the stack gas. The owner or operator may use ANSI/ASME PTC 19.10-1981, "Flue and Exhaust Gas Analyses (incorporated by reference—*see* 40 CFR 60.17) as an alternative to Method 3B of appendix A-2 of this part. (40 CFR 60.257(b)(3))

(d) Method 4 of appendix A-4 of this part shall be used to determine the moisture content of the stack gas. (40 CFR 60.257(b)(4))

(e) Method 5, 5B or 5D of appendix A-4 of this part or Method 17 of appendix A-7 of this part shall be used to determine the PM concentration as follows: (40 CFR 60.257(b)(5))

(i) The sampling time and sample volume for each run shall be at least 60 minutes and 0.85 dscm (30 dscf). Sampling shall begin no less than 30 minutes after startup and shall terminate before shutdown procedures begin. A minimum of three valid test runs are needed to comprise a PM performance test. (40 CFR 60.257(b)(5)(i))

(ii) Method 5 of appendix A of this part shall be used only to test emissions from affected facilities without wet flue gas desulfurization (FGD) systems. (40 CFR 60.257(b)(5)(ii))

(iii) Method 5B of appendix A of this part is to be used only after wet FGD systems. (40 CFR 60.257(b)(5)(iii))

(iv) Method 5D of appendix A-4 of this part shall be used for positive pressure fabric filters and other similar applications (e.g., stub stacks and roof vents). (40 CFR 60.257(b)(5)(iv))

(v) Method 17 of appendix A-6 of this part may be used at facilities with or without wet scrubber systems provided the stack gas temperature does not exceed a temperature of 160 °C (320 °F). The procedures of sections 8.1 and 11.1 of Method 5B of appendix A-3 of this part may be used in Method 17 of appendix A-6 of this part only if it is used after a wet FGD system. Do not use Method 17 of appendix A-6 of this part after wet FGD systems if the effluent is saturated or laden with water droplets. (40 CFR 60.257(b)(5)(v))

iv. The owner or operator of a coal preparation and processing plant that commenced construction, reconstruction, or modification after April 28, 2008, shall maintain in a logbook (written or electronic) on-site and make it available upon request. The logbook shall record the following: (40 CFR 60.258(a))

1) The manufacturer's recommended maintenance procedures and the date and time of any maintenance and inspection activities and the results of those activities. Any variance from manufacturer recommendation, if any, shall be noted. (40 CFR 60.258(a)(1))

2) The date and time of periodic coal preparation and processing plant visual observations, noting those sources with visible emissions along with corrective actions taken to reduce visible emissions. Results from the actions shall be noted. (40 CFR 60.258(a)(2))

3) The amount and type of coal processed each calendar month. (40 CFR 60.258(a)(3))

4) The amount of chemical stabilizer or water purchased for use in the coal preparation and processing plant. (40 CFR 60.258(a)(4))

5) Monthly certification that the dust suppressant systems were operational when any coal was processed and that manufacturer's recommendations were followed for all control systems. Any variance from the manufacturer's recommendations, if any, shall be noted. (40 CFR 60.258(a)(5))

6) Monthly certification that the fugitive coal dust emissions control plan was implemented as described. Any variance from the plan, if any, shall be noted. A copy of the applicable fugitive coal dust emissions control plan and any letters from the Administrator providing approval of any alternative control measures shall be maintained with the logbook. Any actions, e.g. objections, to the plan and any actions relative to the alternative control measures, e.g. approvals, shall be noted in the logbook as well. (40 CFR 60.258(a)(6))

7) For each bag leak detection system, the owner or operator must keep the records specified in paragraphs (a)(7)(i) through (iii) of this section. (40 CFR 60.258(a)(7))

(a) Records of the bag leak detection system output; (40 CFR 60.258(a)(7)(i))

(b) Records of bag leak detection system adjustments, including the date and time of the adjustment, the initial bag leak detection system settings, and the final bag leak detection settings; and (40 CFR 60.258(a)(7)(ii))

(c) The date and time of all bag leak detection system alarms, the time that procedures to determine the cause of the alarm were initiated, the cause of the alarm, an explanation of the actions taken, the date and time the cause of the alarm was alleviated, and whether the cause of the alarm was alleviated within 3 hours of the alarm. (40 CFR 60.258(a)(7)(iii))

8) A copy of any applicable monitoring plan for a digital opacity compliance system and monthly certification that the plan was implemented as described. Any variance from plan, if any, shall be noted. (40 CFR 60.258(a)(8))

9) During a performance test of a wet scrubber, and each operating day thereafter, the owner or operator shall record the measurements of the scrubber pressure loss, water supply flow rate, and pH of the wet scrubber liquid. (40 CFR 60.258(a)(9))

10) During a performance test of control equipment other than a wet scrubber, and each operating day thereafter, the owner or operator shall record the measurements of the reagent injection flow rate, as applicable. (40 CFR 60.258(a)(10))

d. **TAC**

See Plantwide Requirements S2.b.

S3. **Reporting** (Regulation 2.16, section 4.1.9.3)

The owner or operator shall submit quarterly compliance reports that include the information in this section.

a. **PM**

There are no routine reporting requirements for this equipment. (See comment 1)

b. **Opacity**

The owner or operator shall identify all periods of exceeding an opacity standard during a quarterly reporting period. The report shall include the following:

i. Any deviation from the requirement to perform and record the results of visible emission surveys or Method 9 tests;
ii. The number, date, and time of each visible emissions survey where visible emissions were observed and the results of the Method 9 test performed;
iii. Identification of all periods of exceeding the opacity standard; and
iv. Description of any corrective action taken for each exceedance of the opacity standard.

c. **Standards of Performance for Coal Preparation and Processing Plants** (40 CFR 60, Subpart Y)

i. For the purpose of reports required under section 60.7(c), any owner operator subject to the provisions of this subpart also shall report semiannually periods of excess emissions as follow: (40 CFR 60.258(b))

1) The owner or operator of an affected facility with a wet scrubber shall submit semiannual reports to the Administrator or delegated authority of occurrences when the measurements of the scrubber pressure loss, water supply flow rate, or pH of the wet scrubber liquid vary by more than 10 percent from the average determined during the most recent performance test. (40 CFR 60.258(b)(1))

2) The owner or operator of an affected facility with control equipment other than a wet scrubber shall submit semiannual reports to the Administrator or delegated authority of occurrences when the measurements of the reagent injection flow rate, as applicable, vary by more than 10 percent from the average determined during the most recent performance test. (40 CFR 60.258(b)(2))

3) All 6-minute average opacities that exceed the applicable standard. (40 CFR 60.258(b)(3))

ii. The owner or operator of an affected facility shall submit the results of initial performance tests to the Administrator or delegated authority, consistent with the provisions of section 60.8. The owner or operator who elects to comply with the reduced performance testing provisions of sections 60.255(c) or (d) shall include in the performance test report identification of each affected facility that will be subject to the reduced testing. The owner or operator electing to comply with section 60.255(d) shall also include information which demonstrates that the control devices are identical. (40 CFR 60.258(c))

iii. After July 1, 2011, within 60 days after the date of completing each performance evaluation conducted to demonstrate compliance with this subpart, the owner or operator of the affected facility must submit the test data to EPA by successfully entering the data electronically into EPA's WebFIRE data base available at *http://*

cfpub.epa.gov/oarweb/index.cfm?action=fire.main. For performance tests that cannot be entered into WebFIRE (i.e., Method 9 of appendix A-4 of this part opacity performance tests) the owner or operator of the affected facility must mail a summary copy to United States Environmental Protection Agency; Energy Strategies Group; 109 TW Alexander DR; mail code: D243-01; RTP, NC 27711. (40 CFR 60.258(d))

d. **TAC**

See Plantwide Requirements S2.b.

Emission Unit U22: Landfill

U22 Applicable Regulations:

FEDERALLY ENFORCEABLE REGULATIONS		
Regulation	**Title**	**Applicable Sections**
1.14	Control of Fugitive Particulate Emissions	1, 2, 3, 4, 5, 8, 9

DISTRICT ONLY ENFORCEABLE REGULATIONS		
Regulation	**Title**	**Applicable Sections**
5.00	Definitions	1, 2
5.01	General Provisions	1 through 2
5.20	Methodology for Determining Benchmark Ambient Concentration of a Toxic Air Contaminant	1 through 6
5.21	Environmental Acceptability for Toxic Air Contaminants	1 through 5
5.22	Procedures for Determining the Maximum Ambient Concentration of a Toxic Air Contaminant	1 through 5
5.23	Categories of Toxic Air Contaminants	1 through 6

U22 Equipment:

Emission Point	Description	Applicable Regulation	Control ID	Stack ID
E48a	Landfill haul roads	1.14, 5.00, 5.01, 5.20, 5.21, 5.22, 5.23	N/A	N/A
E48b	Landfill drop points		N/A	N/A
E48c	Landfill wind erosion emissions		N/A	N/A

U22 Control Devices:

Particulate emissions from landfill haul roads are controlled according to an approved plantwide Fugitive Dust Control Plan.[128] (See Attachment F)

[128] LG&E submitted a Fugitive Dust Control Plan for Paved & Unpaved Roads on June 28, 2013 and the District approved the plan on 06/05/2014.

U22 Specific Conditions

S1. **Standards (Regulation 2.16, section 4.1.1)**

a. **PM**

The owner or operator shall not allow any materials to be handled, transported, or stored, or a road to be used without taking reasonable precautions to prevent particulate matter from becoming airborne beyond the work site. Such precautions shall include, where applicable, but shall not be limited to the following: (Regulation 1.14, section 2.1)

i. Using, where possible, water or chemicals for control of dust in the grading of roads or the clearing of land,

ii. Applying and maintaining asphalt, oil, water, or suitable chemicals on roads, materials stockpiles, and other surfaces which can create airborne dusts, (Regulation 1.14, section 2.1.2)

iii. Covering at all times, except when loading and unloading, open bodied trucks transporting materials likely to become airborne, (Regulation 1.14, section 2.1.4)

b. **Opacity**

i. The owner or operator shall not allow visible emissions to equal or exceed 20% opacity. (Regulation 1.14, section 2.3)

ii. The owner or operator shall not allow visible fugitive emissions beyond the lot line of the property on which the emissions originate. (Regulation 1.14, section 2.4)

c. **TAC**

See Plantwide Requirements S1.b.[129]

S2. **Monitoring and Record Keeping** (Regulation 2.16, sections 4.1.9.1 and 4.1.9.2)

The owner or operator shall maintain the required records for a minimum of 5 years and make the records readily available to the District upon request.

[129] LG&E submitted a TAC Environmental Acceptability Demonstration for this unit on July 19 and July 31, 2013. It has been demonstrated that the risk values of this unit are in compliance with the EA Goals.

a. **PM**

i. The owner or operator shall keep records of type and amount of the materials transferred to the landfill area.

ii. The owner or operator shall keep records of vehicle miles traveled (VMT) and weights for the vehicles traveled on the landfill area.

b. **Opacity**

See Specific Condition S2.a.

c. **TAC**

See Plantwide Requirements S2.b

S3. **Reporting** (Regulation 2.16, section 4.1.9.3)

The owner or operator shall submit quarterly compliance reports that include the information in this section.

a. **PM/ Opacity**

The owner or operator shall report any deviation from the attached Fugitive Dust Control Plan during the reporting period.

b. **TAC**

See Plantwide Requirements S2.b

Permit Shield

The owner or operator is hereby granted a permit shield that shall apply as long as the owner or operator demonstrates ongoing compliance with all conditions of this permit. Compliance with the conditions of this permit shall be deemed compliance with all applicable requirements of the regulations cited in this permit as of the date of issuance, pursuant to Regulation 2.16, section 4.6.1.

Off-Permit Documents

There are no off permit documents associated with this Title V permit.

Alternative Operating Scenario

The company requested no alternative operating scenario in its Title V application.

Insignificant Activities

Equipment	Quan.	PTE (tpy)	Regulation Basis
Fuel or Lubricating oils storage tanks with vapor pressure <10mm Hg @ 20 deg C (See unit IA-OT)	17	0.005 VOC	Regulation 1.02, Appendix A, 3.9.2
1,000 gallon storage tank for #1 fuel oil with annual turnover < 2X the capacity (See unit IA-OT)	1	0.001 VOC	Regulation 1.02, Appendix A, 3.25
Minor natural gas combustion sources <10 MMBtu/hr (direct heat exchangers)	24	0.79 NOx	Regulation 2.16, section 1.23
Emergency relief vents for boiler steam supply	24	0	Regulation 1.02, Appendix A, 3.10
Lab exhaust systems	3	0.001 VOC	Regulation 1.02, Appendix A, 3.11
Portable kerosene storage tanks with capacity less than 500 gallons (See unit IA-OT)	1	3.5e-5 VOC	Regulation 1.02, Appendix A, 3.23
Ash pond with wet storage	1	0	Regulation 2.16, section 1.23
Cooling Towers for Unit 2 and Unit 3 (See unit IA-OT)	2	3.35 PM_{10}	Regulation 2.16, section 1.23
Stockpiles (coal, limestone, gypsum piles)	3	1.66 PM_{10}	Regulation 2.16, section 1.23
Turbine oil reservoir vapor extractor	4	0	Regulation 2.16, section 1.23
Hydrogen seal oil tank vent	4	0	Regulation 2.16, section 1.23
Gypsum handling equipment (See unit IA-OT)	1	4.69 PM_{10}	Regulation 2.16, section 1.23
Portable gypsum dewatering systems (See unit IA-OT)	2	1.27 PM_{10}	Regulation 2.16, section 1.23
Gasoline storage tank, 3,000 gallons (previous U10, see unit IA1)	1	1.87 VOC	Regulation 2.16, section 1.23
Non-halogenated cold solvent parts washers with secondary reservoir (previous U11, see unit IA2)	8	0.33 VOC	Regulation 2.16, section 1.23

Equipment	Quan.	PTE (tpy)	Regulation Basis
Emergency generators, 800 HP each (previous U13, see unit IA3)	2	4.93 NOx	Regulation 2.16, section 1.23
Fire pumps, 157 HP and 183 HP (See unit IA4)	2	1.42 NOx	Regulation 2.16, section 1.23
Emergency vent for U1 and U2 boilers	1	0.7 NOx	Regulation 2.16, section 1.23
Bottom/flyash silos (See unit IA-OT)	2	2.34 PM_{10}	Regulation 2.16, section 1.23
Ash pug mill mixers (See unit IA-OT)	4	4.7 PM_{10}	Regulation 2.16, section 1.23
Process water system (See unit IA-OT)	1	1.69 PM_{10}	Regulation 2.16, section 1.23
Emergency generator, natural gas fired, 105 HP (See unit IA3)	1	0.75 CO	Regulation 2.16, section 1.23

1) Insignificant Activities identified in District Regulation 1.02 Appendix A may be subject to size or production rate disclosure requirements.

2) Insignificant Activities identified in District Regulation 1.02 Appendix A shall comply with generally applicable requirements.

3) Activities identified in Regulation 1.02, Appendix A, may not require a permit and may be insignificant with regard to application disclosure requirements but may still have generally applicable requirements that continue to apply to the source and must be included in the permit.

4) Emissions from Insignificant Activities shall be reported in conjunction with the reporting of annual emissions of the facility as required by the District.

5) In lieu of recording annual throughputs and calculating actual annual emissions, the owner or operator may elect to report the pollutant Potential To Emit (PTE) quantity listed in the Insignificant Activities table, as the annual emission for each piece of equipment.

6) The Insignificant Activities Table is correct as of the date the permit was proposed for review by U.S. EPA, Region 4.

7) The owner or operator shall submit an updated list of Insignificant Activities whenever changes in equipment located at the facility occur that cause changes to the plant wide emissions.

Emission Unit IA1: Gasoline storage tank [130]

IA1 Applicable Regulations:

FEDERALLY ENFORCEABLE REGULATIONS		
Regulation	**Title**	**Applicable Sections**
6.40	Standards of Performance for Gasoline Transfer to Motor Vehicles (Stage II Vapor Recovery)	1.3
7.15	Standards of Performance for Gasoline Transfer to New Service Station Storage Tanks (Stage I Vapor Recovery)	1, 2, 3.1, 3.3, 3.4, 3.6, 3.7, 3.8, and 5

IA1 Equipment:[131]

Emission Point	Description	Applicable Regulation	Control ID
E20	One (1) Stage I gasoline refueling station, including one 3,000 gallon unleaded gasoline storage tank	6.40 and 7.15	N/A

IA1 Control Devices:

This unit is equipped with a Stage I vapor recovery system.

[130] Per Regulation 5.21, section 2.3, emissions from insignificant activity are de minimis.

[131] The storage tank under this unit meets the definition of insignificant activities per Regulation 2.16, section 1.23. However, Regulation 6.40 or 7.15 applies to gasoline storage vessels. These tanks shall meet the requirements under Regulation 6.40 or 7.15.

IA1 Specific Conditions

S1. **Standards** (Regulation 2.16, section 4.1.1)

VOC (Regulation 7.15, section 3 and Regulation 6.40, section 1.3)

i. The owner or operator of an affected facility shall install, maintain, and operate the following devices on the storage tank: (Regulation 7.15, section 3.1)

1) Submerged fill pipe; (Regulation 7.15, section 3.1.1)
2) If the gasoline storage tank is equipped with a separate gauge well, a gauge well drop tube shall be installed which extends to within six inches of the bottom of the tank; (Regulation 7.15, section 3.1.2)
3) Vent line restrictions on the affected facility; and (Regulation 7.15, section 3.1.3)
4) Vapor balance system and vapor tight connections on the liquid fill and vapor return hoses. The cross-sectional area of the vapor return hose and any other vapor return passages in the circuit connecting the vapor space in the service station tank to that of the truck tank must be at least 50% of the liquid fill hose cross-sectional area for each tank and free of flow restrictions to achieve acceptable recovery. The vapor balance equipment must be maintained according to the manufacturer's specifications. The type, size and design of the vapor balance system are subject to the approval of the District. (Regulation 7.15, section 3.1.4)

ii. The owner or operator shall not allow delivery of fuel to the storage tanks until the vapor balance system is properly connected to the transport vehicle and the affected facility. (Regulation 7.15, section 3.3)

iii. No person shall deliver gasoline to a service station as defined in Regulation 7.15 without connecting the vapor return hose between the tank of the delivery truck and the storage tank receiving the product. The vapor balance system must be operating in accordance with the manufacturer's specifications. (Regulation 7.15, section 3.4)

iv. The owner or operator shall equip above ground tanks with dry breaks with any liquid spillage upon the line disconnect not exceeding 10 ml. (Regulation 7.15, section 3.7)

v. The owner or operator shall operate and maintain equipment with no defects and: (Regulation 7.15, section 3.8)

1) All fill tubes shall be equipped with vapor-tight covers including gaskets, (Regulation 7.15, section 3.8.1)

2) All dry breaks shall have vapor-tight seals and shall be equipped with vapor-tight covers or dust covers, (Regulation 7.15, section 3.8.2)

3) All vapor return passages shall be operated so there can be no obstruction of vapor passage from the storage tank back to the delivery vehicle, (Regulation 7.15, section 3.8.3)

4) All storage tank vapor return pipes and fill pipes without dry breaks shall be equipped with vapor-tight covers including gaskets, and (Regulation 7.15, section 3.8.4)

5) All hoses, fittings, and couplings shall be in a vapor-tight condition. (Regulation 7.15, section 3.8.5)

vi. The owner or operator shall not dispense more than 10,000 gallons per month based on the average volume of gasoline dispensed during any consecutive 12 months. (Regulation 6.40, section 1.1)

S2. **Monitoring and Record Keeping** (Regulation 2.16, sections 4.1.9.1 and 4.1.9.2)

The owner or operator shall maintain the following records for a minimum of 5 years and make the records readily available to the District upon request.

VOC

The owner or operator shall keep a record of the amount of throughput of gasoline per month to determine compliance with Specific Condition S1.vi. (Regulation 6.40, section 3.1.1)

S3. **Reporting** (Regulation 2.16, section 4.1.9.3)

The owner or operator shall submit compliance reports that include the information in this section.

VOC

The owner or operator shall submit a report by April 15th every year showing that they are still exempt from Regulation 6.40. (Regulation 6.40, section 2.2.1)

Emission Unit IA2: Parts washers with secondary reservoirs[132]

IA2 Applicable Regulations:

FEDERALLY ENFORCEABLE REGULATIONS		
Regulation	**Title**	**Applicable Sections**
6.18	Standards of Performance for Solvent metal Cleaning Equipment	1 through 6

IA2 Equipment:[133]

Emission Point	Description	Applicable Regulation	Control ID
IE1 – IE8	Eight (8) parts washers each equipped with a secondary reservoir	6.18	N/A

IA2 Control Devices:

There are no control devices associated with emission unit IA2.

[132] Per Regulation 5.21, section 2.3, emissions from insignificant activity are de minimis.

[133] The parts washers under this unit meet the definition of insignificant activities per Regulation 2.16, section 1.23. However, Regulation 6.18 applies to each cold cleaner that uses VOC to remove soluble impurities from metal surfaces. These parts washers shall meet the requirements under Regulation 6.18.

IA2 Specific Conditions

S1. **Standards** (Regulation 2.16, section 4.1.1)

VOC

a. The owner or operator shall install, maintain, and operate the control equipment as follows: (Regulation 6.18, section 4.1)

i. The cold cleaner shall be equipped with a tightly fitting cover that is free of cracks, holes, or other defects. If the solvent is agitated or heated, then the cover shall be designed so that it can be easily operated with 1 hand. (Regulation 6.18, section 4.1.1)

ii. The cold cleaner shall be equipped with a drainage facility that is designed so that the solvent that drains off parts removed from the cleaner will return to the cold cleaner. The drainage facility may be external if the District determines that an internal type cannot fit into the cleaning system. (Regulation 6.18, section 4.1.2)

iii. A permanent, conspicuous label summarizing the operating requirements specified in Specific Condition S1.b. shall be installed on or near the cold cleaner. (Regulation 6.18, section 4.1.3)

iv. If used, the solvent spray shall be a fluid stream, not a fine, atomized, or shower type spray, at a pressure that does not cause excessive splashing. Flushing of parts using a flexible hose or other flushing device shall be performed only within the freeboard area of the cold cleaner. Solvent flow shall be directed downward to avoid turbulence at the air-solvent interface and to prevent solvent from splashing outside of the cold cleaner. (Regulation 6.18, section 4.1.4)

v. Work area fans shall be located and positioned so that they do not blow across the opening of the cold cleaner. (Regulation 6.18, section 4.1.6)

vi. The solvent-containing portion of the cold cleaner shall be free of all liquid leaks. Auxiliary cold cleaner equipment such as pumps, water separators, steam traps, or distillation units shall not have any visible liquid leaks, visible tears, or cracks. (Regulation 6.18, section 4.1.8)

b. The owner or operator shall observe at all times the following operating requirements: (Regulation 6.18, section 4.2)

i. Waste solvent shall neither be disposed of nor transferred to another party in a manner such that more than 20% by weight of the waste solvent can evaporate. Waste solvent shall be stored only in a covered container. A covered container may contain a device that allows pressure relief, but does not allow liquid solvent to drain from the container. (Regulation 6.18, section 4.2.1)

ii. The solvent level in the cold cleaner shall not exceed the fill line. (Regulation 6.18, section 4.2.2)

iii. The cold cleaner cover shall be closed whenever a part is not being handled in the cold cleaner. (Regulation 6.18, section 4.2.3)

iv. Parts to be cleaned shall be racked or placed into the cold cleaner in a manner that will minimize drag-out losses. (Regulation 6.18, section 4.2.4)

v. Cleaned parts shall be drained for at least 15 seconds or until dripping ceases, whichever is longer. Parts having cavities or blind holes shall be tipped or rotated while the part is draining. During the draining, tipping, or rotating, the parts shall be positioned so that the solvent drains directly back to the cold cleaner. (Regulation 6.18, section 4.2.5)

vi. A spill during solvent transfer shall be cleaned immediately, and the wipe rags or other sorbent material shall be immediately stored in a covered container for disposal or recycling, unless enclosed storage of these items is not allowed by fire protection authorities. (Regulation 6.18, section 4.2.6)

vii. Sponges, fabric, wood, leather, paper products, and other absorbent material shall not be cleaned in a cold cleaner. (Regulation 6.18, section 4.2.7)

c. The owner or operator shall not operate a cold cleaner using a solvent with a vapor pressure that exceeds 1.0 mm Hg (0.019 psi) measured at 20EC (68EF). (Regulation 6.18, section 4.3.2)

S2. **Monitoring and Record Keeping** (Regulation 2.16, sections 4.1.9.1 and 4.1.9.2)

VOC

a. The owner or operator shall maintain records that include the following for each purchase: (Regulation 6.18, section 4.4.2)

i. The name and address of the solvent supplier,
ii. The date of the purchase,
iii. The type of the solvent, and
iv. The vapor pressure of the solvent measured in mm Hg at 20EC (68EF).

b. All records required in Specific Condition S2.a shall be retained for 5 years and made available to the District upon request. (Regulation 6.18, section 4.4.3)

S3. **Reporting** (Regulation 2.16, section 4.1.9.3)

VOC

There are no routine compliance reporting requirements for Regulation 6.18.

Emission Unit IA3: Emergency generators[134]

IA3 Applicable Regulations:

FEDERALLY ENFORCEABLE REGULATIONS		
Regulation	**Title**	**Applicable Sections**
40 CFR 63, Subpart ZZZZ	National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines	63.6603, 6604, 6605, 6625, 6640, 6645, 6655
40 CFR 60, Subpart IIII	Standards of Performance for Stationary Compression Ignition Internal Combustion Engines	60.4200 - 4219

IA3 Equipment:[135,136]

Emission Point	Description	Applicable Regulation	Control ID	Stack ID
E36	One (1) Turning Gear diesel generator, make Caterpillar, model C18, rated at 800 HP (597 KW) with an internal 404 gallon diesel fuel tank. Model year 2007 (Tier 2)[137]	40 CFR 63, Subpart ZZZZ, 40 CFR 60, Subpart IIII	N/A	N/A
E37	One (1) diesel generator for FGD Quench Water system, make Caterpillar, model 3412, rated at 800 HP (597 KW) with an internal 450 gallon diesel fuel tank. Model year 2005 (Tier 1)[137]	40 CFR 63, Subpart ZZZZ		
IE24	One (1) new natural gas fired emergency generator, make Kohler, model 60REZGB, rated output capacity 105 HP (78.3 kW). [137]	40 CFR 63, Subpart ZZZZ, 40 CFR 60, Subpart JJJJ	N/A	N/A

IA3 Control Devices:

[134] Per Regulation 5.21, section 2.3, emissions from insignificant activity are de minimis.

[135] This unit was previously permitted under construction permit 426-07. The associated internal storage tank for diesel fuel is exempt from District permitting requirements in accordance with Regulation 1.02, section 3.9.2.

[136] Potential emissions for this permitted operation are greatest for nitrogen oxides (NOx). Based on AP-42 Emission Factors and 500 hours per year for an emergency generator, as defined by EPA, the potential NOx emissions for this permitted operation is less than 5 tons per year.

[137] These engines (E36, E37, IE24) are subject to 40 CFR 63, Subpart ZZZZ, National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines, because it involves a stationary reciprocating internal combustion engine (RICE) located at a major source of HAP emissions. Engine E36 is also subject 40 CFR 60, Subpart IIII since it is a new compress ignition (CI) engine according to its manufacture date and installation date. Engine E37 is also subject 40 CFR 60, Subpart JJJJ since it is a new spark ignition (SI) engine according to its manufacture date and installation date.

There are no control devices associated with this equipment.

IA3 Specific Conditions

S1. **Standards** (Regulation 2.16, section 4.1.1)

a. **Unit Operation**

For E36 (condition i through vi):

i. The owner or operator of 2007 model year or later emergency stationary CI ICE with a displacement of less than 30 liters per cylinder that are not fire pump engines must comply with the emission standards for new nonroad CI engines in 40 CFR 60.4202, for all pollutants, for the same model year and maximum engine power for their 2007 model year and later emergency stationary CI ICE. (40 CFR 60.4205(b))

Engine manufacturers shall certify the engines with the exhaust emission standards in the following table. In lieu of the NO_X standards, NMHC + NO_X standards, and PM standards, manufacturers may elect to include engine families in the averaging, banking, and trading program. The manufacturer must set a family emission limit (FEL) not to exceed the levels contained in the following table: (40 CFR 60.4202(a) refers to 40 CFR 89.112 and 113)

unit: g/KW-hr	NO_x	HC	NMHC+ NO_x	CO	PM
Emission Standards (Table 1 to 40 CFR 89.112(a))	N/A	N/A	6.4	3.5	0.2
Family Emission Limits (Table 2 to 40 CFR 89.112(d))	N/A	N/A	10.5	N/A	0.54
Smoke emission standard (40 CFR 89.113(a)	1) 20% during the acceleration mode; 2) 15% during the lugging mode; 3) 50% during the peaks in either the acceleration or lugging modes.				

ii. The owner or operator must operate and maintain stationary CI ICE that achieve the emission standards as required in 40 CFR 60.4205 over the entire life of the engine. (40 CFR 60.4206)

iii. Beginning October 1, 2010, the owner or operator of a stationary CI ICE subject to this subpart with a displacement of less than 30 liters per cylinder that uses diesel fuel shall use diesel fuel that meets the requirements of 40 CFR 80.510(b) for nonroad diesel fuel, except that any existing diesel fuel purchased (or otherwise obtained) prior to October 1, 2010, may be used until depleted: (40 CFR 60.4207(b))

1) Sulfur content: 15 parts per million (ppm) maximum for NR diesel fuel. (40 CFR 80.510(b)(1)(i))

2) A minimum cetane index of 40; or (40 CFR 80.510(b)(2)(i))
3) A maximum aromatic content of 35 volume percent. (40 CFR 80.510(b)(2)(ii))

iv. The owner or operator that must comply with the emission standards specified in 40 CFR 60, Subpart IIII shall do all of the following: (40 CFR 60.4211(a))

1) Operate and maintain the stationary CI internal combustion engine and control device according to the manufacturer's emission-related written instructions; (40 CFR 60.4211(a)(1))

2) Change only those emission-related settings that are permitted by the manufacturer; (40 CFR 60.4211(a)(2))

v. The owner or operator shall purchase an engine certified to the emission standards in 40 CFR 60.4205(b), as applicable for the same model year and maximum engine power. The engine must be installed and configured according to the manufacturer's specifications. (40 CFR 60.4211(c))

vi. In order for the engine to be considered an emergency stationary ICE under this subpart, any operation other than emergency operation, maintenance and testing, emergency demand response, and operation in non-emergency situations for 50 hours per year, as described in 60 CFR 60.4211(f)(1) through (3), is prohibited. If the owner or operator does not operate the engine according to the requirements in 60 CFR 60.4211(f)(1) through (3), the engine will not be considered an emergency engine under this subpart and must meet all requirements for non-emergency engines. (40 CFR 60.4211(f))

1) There is no time limit on the use of emergency stationary ICE in emergency situations. (40 CFR 60.4211(f)(1))

2) The owner or operator may operate the emergency stationary ICE for any combination of the purposes specified in 60 CFR 60.4211(f)(2)(i) through (iii) for a maximum of 100 hours per calendar year. Any operation for non-emergency situations as allowed by 60 CFR 60.4211(f)(3) counts as part of the 100 hours per calendar year allowed by this paragraph. (40 CFR 60.4211(f)(2)).

(a) Emergency stationary ICE may be operated for maintenance checks and readiness testing, provided that the tests are recommended by federal, state or local government, the manufacturer, the vendor, the regional transmission organization or equivalent balancing authority and transmission operator, or the insurance company associated with the engine. The owner or operator may petition the Administrator for approval of additional hours to be used for maintenance checks and readiness testing, but a petition is not required if the owner or operator maintains records indicating that federal, state, or local standards require maintenance and testing of emergency ICE beyond 100 hours per calendar year. (40 CFR 60.4211(f)(2)(i))

(b) Emergency stationary ICE may be operated for emergency demand response for periods in which the Reliability Coordinator under the North American Electric Reliability Corporation (NERC) Reliability Standard EOP-002-3, Capacity and Energy Emergencies (incorporated by reference, see 40 CFR 60.17), or other authorized entity as determined by the Reliability Coordinator, has declared an Energy Emergency Alert Level 2 as defined in the NERC Reliability Standard EOP-002-3. (40 CFR 60.4211(f)(2)(ii))

(c) Emergency stationary ICE may be operated for periods where there is a deviation of voltage or frequency of 5 percent or greater below standard voltage or frequency. (40 CFR 60.4211(f)(2)(iii))

3) Emergency stationary ICE may be operated for up to 50 hours per calendar year in non-emergency situations. The 50 hours of operation in non-emergency situations are counted as part of the 100 hours per calendar year for maintenance and testing and emergency demand response provided in 40 CFR 60.4211(f)(2). Except as provided in 40 CFR 60.4211(f)(3)(i), the 50 hours per calendar year for non-emergency situations cannot be used for peak shaving or non-emergency demand response, or to generate income for a facility to an electric grid or otherwise supply power as part of a financial arrangement with another entity. (40 CFR 60.4211(f)(3))

(a) The 50 hours per year for non-emergency situations can be used to supply power as part of a financial arrangement with another entity if all of the following conditions are met: (40 CFR 60.4211(f)(3)(i))

(i) The engine is dispatched by the local balancing authority or local transmission and distribution system operator; (40 CFR 60.4211(f)(3)(i)(A))

(ii) The dispatch is intended to mitigate local transmission and/or distribution limitations so as to avert potential voltage collapse or line overloads that could lead to the interruption of power supply in a local area or region. (40 CFR 60.4211(f)(3)(i)(B))

(iii) The dispatch follows reliability, emergency operation or similar protocols that follow specific NERC, regional, state, public utility commission or local standards or guidelines. (40 CFR 60.4211(f)(3)(i)(C))

(iv) The power is provided only to the facility itself or to support the local transmission and distribution system. (40 CFR 60.4211(f)(3)(i)(D))

(v) The owner or operator identifies and records the entity that dispatches the engine and the specific NERC, regional, state, public utility commission or local standards or guidelines that are being followed for dispatching the engine. The local balancing authority or local transmission and distribution system operator may keep these records on behalf of the engine owner or operator. (40 CFR 60.4211(f)(3)(i)(E))

<u>For IE24: (condition vii through xii):</u>

vii. Owners and operators of stationary spark-ignition internal combustion engine that commence construction after June 12, 2006, where the stationary SI ICE are manufactured on or after July 1, 2008, for engines with a maximum engine power less than 500 HP are subject to the provisions of 40 CFR 60, Subpart JJJJ. (40 CFR 60.4230(a)(4) and 40 CFR 60.4230(a)(4)(iii))

viii. Owners and operators of stationary SI ICE with a maximum engine power greater than or equal to 75 KW (100 HP) (except gasoline and rich burn engines that use LPG) must comply with the emission standards in Table 1 to this subpart for their stationary SI ICE, as the following: (40 CFR 60.4233(e))

Table 1 to Subpart JJJJ of Part 60 —NO_X, CO, and VOC Emission Standards for Stationary Emergency Engines >25 HP

Engine type	**Maximum engine power**	**Manufacture date**	**Emission standards** [a]		
			g/HP-hr		
			NO_X + HC	CO	VOC
Emergency	25<HP<130	1/1/2009	10	387	N/A

ix. Owners and operators of stationary spark-ignition internal combustion engine must operate and maintain stationary SI ICE that achieve the emission standards §60.4233 over the entire life of the engine. (40 CFR 60.4234)

x. If you are an owner or operator of a stationary SI internal combustion engine and must comply with the emission standards specified in 40 CFR 60.4233(d) or (e), you must demonstrate compliance according to one of the methods specified in paragraphs (b)(1) and (2) of this section. (40 CFR 60.4243(b))

1) Purchasing an engine certified according to procedures specified in this subpart, for the same model year and demonstrating compliance according to one of the methods specified in paragraph (a) of this section, as the following: [138] (40 CFR 60.4243(b)(1))

(a) If you operate and maintain the certified stationary SI internal combustion engine and control device according to the manufacturer's emission-related written instructions, you must keep records of conducted maintenance to demonstrate compliance, but no performance testing is required if you are an owner or operator. You must also meet the requirements as specified in 40 CFR part 1068, subparts A through D, as they apply to you. If you adjust engine settings according to and consistent with the manufacturer's instructions, your stationary SI internal combustion engine will not be considered out of compliance. (40 CFR 60.4243(a)(1))

(b) If you do not operate and maintain the certified stationary SI internal combustion engine and control device according to the manufacturer's emission-related written instructions, your engine will be considered a non-certified engine, and you must demonstrate compliance according to (a)(2)(i) through (iii) of this section, as appropriate. (40 CFR 60.4243(a)(2))

(i) If you are an owner or operator of a stationary SI internal combustion engine less than 100 HP, you must keep a maintenance plan and records of conducted maintenance to demonstrate compliance and must, to the extent practicable, maintain and operate the engine in a manner consistent with good air pollution control practice for minimizing emissions, but no performance testing is required if

[138] The District received engine certification of conformity for IA24 on 10/26/2018.

you are an owner or operator. (40 CFR 60.4243(a)(2)(i))

(ii) If you are an owner or operator of a stationary SI internal combustion engine greater than or equal to 100 HP and less than or equal to 500 HP, you must keep a maintenance plan and records of conducted maintenance and must, to the extent practicable, maintain and operate the engine in a manner consistent with good air pollution control practice for minimizing emissions. In addition, you must conduct an initial performance test within 1 year of engine startup to demonstrate compliance. (40 CFR 60.4243(a)(2)(ii))

(iii) If you are an owner or operator of a stationary SI internal combustion engine greater than 500 HP, you must keep a maintenance plan and records of conducted maintenance and must, to the extent practicable, maintain and operate the engine in a manner consistent with good air pollution control practice for minimizing emissions. In addition, you must conduct an initial performance test within 1 year of engine startup and conduct subsequent performance testing every 8,760 hours or 3 years, whichever comes first, thereafter to demonstrate compliance. (40 CFR 60.4243(a)(2)(iii))

2) Purchasing a non-certified engine and demonstrating compliance with the emission standards specified in 40 CFR 60.4233(d) or (e) and according to the requirements specified in 40 CFR 60.4244, as applicable, and according to paragraphs (b)(2)(i) and (ii) of this section. (40 CFR 60.4243(b)(2))

(a) If you are an owner or operator of a stationary SI internal combustion engine greater than 25 HP and less than or equal to 500 HP, you must keep a maintenance plan and records of conducted maintenance and must, to the extent practicable, maintain and operate the engine in a manner consistent with good air pollution control practice for minimizing emissions. In addition, you must conduct an initial performance test to demonstrate compliance. (40 CFR 60.4243(b)(2)(i))

(b) If you are an owner or operator of a stationary SI internal combustion engine greater than 500 HP, you must keep a maintenance plan and records of conducted maintenance and must, to the extent practicable, maintain and operate the engine in a manner consistent with good air pollution control practice for minimizing emissions. In addition, you must conduct an initial performance test and conduct subsequent performance testing every 8,760 hours or 3 years, whichever comes first, thereafter to demonstrate compliance. (40 CFR 60.4243(b)(2)(ii))

xi. In order for the engine to be considered an emergency stationary ICE under this subpart, any operation other than emergency operation, maintenance and testing, emergency demand response, and operation in non-emergency situations for 50 hours per year, as described 40 CFR 60.4243(d), is prohibited. If the owner or operator does not operate the engine according to the requirements in 40 CFR 60.4243(d), the engine will not be considered an emergency engine under this subpart and must meet all requirements for non-emergency engines. (40 CFR 60.4243(d))

1) There is no time limit on the use of emergency stationary ICE in emergency situations. (40 CFR 60.4243(d)(1))

2) The owner or operator may operate the emergency stationary ICE for any combination of the purposes specified in 40 CFR 60.4243(d)(2) for a maximum of 100 hours per calendar year. Any operation for non-emergency situations as allowed 40 CFR 60.4243(d)(3) counts as part of the 100 hours per calendar year allowed by this paragraph. (40 CFR 60.4243(d)(2))

(a) Emergency stationary ICE may be operated for maintenance checks and readiness testing, provided that the tests are recommended by federal, state or local government, the manufacturer, the vendor, the regional transmission organization or equivalent balancing authority and transmission operator, or the insurance company associated with the engine. The owner or operator may petition the Administrator for approval of additional hours to be used for maintenance checks and readiness testing, but a petition is not required if the owner or operator maintains records indicating that federal, state, or local standards require maintenance and testing of emergency ICE beyond 100 hours per calendar year. (40 CFR 60.4243(d)(2)(i))

(b) Emergency stationary ICE may be operated for emergency demand response for periods in which the Reliability Coordinator under the North American Electric Reliability Corporation (NERC) Reliability Standard EOP-002-3, Capacity and Energy Emergencies (incorporated by reference, see 40 CFR 60.17), or other authorized entity as determined by the Reliability Coordinator, has declared an

Energy Emergency Alert Level 2 as defined in the NERC Reliability Standard EOP-002-3. (40 CFR 60.4243(d)(2)(ii))

(c) Emergency stationary ICE may be operated for periods where there is a deviation of voltage or frequency of 5 percent or greater below standard voltage or frequency. (40 CFR 60.4243(d)(2)(iii))

3) Emergency stationary ICE may be operated for up to 50 hours per calendar year in non-emergency situations. The 50 hours of operation in non-emergency situations are counted as part of the 100 hours per calendar year for maintenance and testing and emergency demand response provided in 40 CFR 60.4243(d)(2). Except as provided in 40 CFR 60.4243(d) (3)(i), the 50 hours per year for non-emergency situations cannot be used for peak shaving or non-emergency demand response, or to generate income for a facility to an electric grid or otherwise supply power as part of a financial arrangement with another entity. (40 CFR 60.4243(d)(3))

(a) The 50 hours per year for non-emergency situations can be used to supply power as part of a financial arrangement with another entity if all of the following conditions are met: (40 CFR 60.4243(d)(3)(i))

(i) The engine is dispatched by the local balancing authority or local transmission and distribution system operator; (40 CFR 60.4243(d)(3)(i)(A))

(ii) The dispatch is intended to mitigate local transmission and/or distribution limitations so as to avert potential voltage collapse or line overloads that could lead to the interruption of power supply in a local area or region. (40 CFR 60.4243(d)(3)(i)(B))

(iii) The dispatch follows reliability, emergency operation or similar protocols that follow specific NERC, regional, state, public utility commission or local standards or guidelines. (40 CFR 60.4243(d)(3)(i)(C))

(iv) The power is provided only to the facility itself or to support the local transmission and distribution system. (40 CFR 60.4243(d)(3)(i)(D))

(v) The owner or operator identifies and records the entity that dispatches the engine and the specific NERC, regional, state, public utility commission or local standards or guidelines that are being followed for dispatching the engine. The local balancing authority or local transmission and distribution system operator may keep these records on behalf of the engine owner or operator. (40 CFR 60.4243(d)(3)(i)(E))

xii. Owners and operators of stationary SI natural gas fired engines may operate their engines using propane for a maximum of 100 hours per year as an alternative fuel solely during emergency operations, but must keep records of such use. If propane is used for more than 100 hours per year in an engine that is not certified to the emission standards when using propane, the owners and operators are required to conduct a performance test to demonstrate compliance with the emission standards of 40 CFR 60.4233. (40 CFR 60.4243(e))

b. **HAP**

<u>For E36 and IE24:</u>

i. The equipment listed in this emission unit is subject to 40 CFR 63, Subpart ZZZZ, however, there are no applicable HAP standards in this regulation.[139]

<u>For E37: (condition ii through iv):</u>

ii. Beginning January 1, 2015, the owner or operator shall not combust in the engine a nonroad diesel fuel that contains more than 15 ppm of sulfur. The diesel fuel shall meet the requirements in 40 CFR 80.510(b) for nonroad diesel fuel, except that any existing diesel fuel purchased (or otherwise obtained) prior to January 1, 2015, may be used until depleted. (40 CFR 63.6604(c))

iii. At all times the owner or operator shall operate and maintain any affected source, including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. The general duty to minimize emissions does not require the owner or operator to make any further efforts to reduce emissions if levels required by this standard have been achieved. Determination of whether such operation and maintenance procedures are being used will be based on information available to the Administrator

[139] According to 40 CFR 63.6590(c), E36 and IE24 must meet the requirements of this part by meeting the requirements of 40 CFR part 60 subpart IIII, for compression ignition engines and 40 CFR part 60 subpart JJJJ, for spark ignition engines. No further requirements apply for E36 and IE24 under 40 CFR 63.

which may include, but is not limited to, monitoring results, review of operation and maintenance procedures, review of operation and maintenance records, and inspection of the source. (40 CFR 63.6605(b))

iv. In order for the engine to be considered an emergency stationary ICE, any operation other than emergency operation, maintenance and testing, emergency demand response, and operation in non-emergency situations for 50 hours per year, as described in 40 CFR 63.6640(f)(1) through (3), is prohibited. If the owner or operator does not operate the engine according to the requirements in 40 CFR 60.4211(f)(1) through (3), the engine will not be considered an emergency engine and must meet all requirements for non-emergency engines. (40 CFR 63.6640(f))

1) There is no time limit on the use of emergency stationary ICE in emergency situations. (40 CFR 60.4211(f)(1), 40 CFR 63.6640(f)(1))

2) The owner or operator may operate the emergency stationary ICE for any combination of the purposes specified in 40 CFR 60.4211(f)(2)(i) through (iii) for a maximum of 100 hours per calendar year. Any operation for non-emergency situations as allowed by 40 CFR 60.4211(f)(3) counts as part of the 100 hours per calendar year allowed by this paragraph. (40 CFR 63.6640(f)(2)).

(a) Emergency stationary ICE may be operated for maintenance checks and readiness testing, provided that the tests are recommended by federal, state or local government, the manufacturer, the vendor, the regional transmission organization or equivalent balancing authority and transmission operator, or the insurance company associated with the engine. The owner or operator may petition the Administrator for approval of additional hours to be used for maintenance checks and readiness testing, but a petition is not required if the owner or operator maintains records indicating that federal, state, or local standards require maintenance and testing of emergency ICE beyond 100 hours per calendar year. (40 CFR 63.6640(f)(2)(i))

(b) Emergency stationary ICE may be operated for emergency demand response for periods in which the Reliability Coordinator under the North American Electric Reliability Corporation (NERC) Reliability Standard EOP-002-3, Capacity and Energy Emergencies (incorporated by reference, see 40 CFR 60.17), or other authorized entity as determined by the Reliability Coordinator, has declared an

Energy Emergency Alert Level 2 as defined in the NERC Reliability Standard EOP-002-3. (40 CFR 63.6640(f)(2)(ii))

(c) Emergency stationary ICE may be operated for periods where there is a deviation of voltage or frequency of 5 percent or greater below standard voltage or frequency. (40 CFR 63.6640(f)(2)(iii)))

3) Emergency stationary ICE may be operated for up to 50 hours per calendar year in non-emergency situations. The 50 hours of operation in non-emergency situations are counted as part of the 100 hours per calendar year for maintenance and testing and emergency demand response provided in 40 CFR 60.4211(f)(2). Except as provided in 40 CFR 60.4211(f)(3)(i), the 50 hours per calendar year for non-emergency situations cannot be used for peak shaving or non-emergency demand response, or to generate income for a facility to an electric grid or otherwise supply power as part of a financial arrangement with another entity. (40 CFR 63.6640(f)(3))

(a) The 50 hours per year for non-emergency situations can be used to supply power as part of a financial arrangement with another entity if all of the following conditions are met: (40 CFR 63.6640(f)(3)(i))

(i) The engine is dispatched by the local balancing authority or local transmission and distribution system operator; (40 CFR 63.6640(f)(3)(i)(A))

(ii) The dispatch is intended to mitigate local transmission and/or distribution limitations so as to avert potential voltage collapse or line overloads that could lead to the interruption of power supply in a local area or region. (40 CFR 63.6640(f)(3)(i)(B))

(iii) The dispatch follows reliability, emergency operation or similar protocols that follow specific NERC, regional, state, public utility commission or local standards or guidelines. (40 CFR 63.6640(f)(3)(i)(C))

(iv) The power is provided only to the facility itself or to support the local transmission and distribution system. (40 CFR 63.6640(f)(3)(i)(D))

(v) The owner or operator identifies and records the entity that dispatches the engine and the specific

NERC, regional, state, public utility commission or local standards or guidelines that are being followed for dispatching the engine. The local balancing authority or local transmission and distribution system operator may keep these records on behalf of the engine owner or operator. (40 CFR 63.6640(f)(3)(i)(E))

S2. **Monitoring and Record Keeping** (Regulation 2.16, sections 4.1.9.1 and 4.1.9.2)

The owner or operator shall maintain the required records for a minimum of 5 years and make the records readily available to the District upon request.

a. **Unit Operation**

For E36: (condition i through iii)

i. The owner or operator of an emergency stationary CI internal combustion engine that does not meet the standards applicable to non-emergency engines, the owner or operator shall install a non-resettable hour meter prior to startup of the engine. (40 CFR 60.4209(a))

ii. The owner or operator is not required to submit an initial notification. Starting with the model years in table 5 to this subpart, if the emergency engine does not meet the standards applicable to non-emergency engines in the applicable model year, the owner or operator shall keep records of the operation of the engine in emergency and non-emergency service that are recorded through the non-resettable hour meter. The owner must record the time of operation of the engine and the reason the engine was in operation during that time. (40 CFR 60.4214(b))

iii. The owner or operator shall maintain records of the fuel MSDS sheets and receipts showing dates, amounts of fuel purchased, sulfur content of fuel purchased and supplier's name and address.

For IE24: (condition iv through v)

iv. Owners and operators of all stationary SI ICE must keep records of the information in paragraphs (a)(1) through (4) of this section. (40 CFR 60.4245(a))

1) All notifications submitted to comply with this subpart and all documentation supporting any notification. (40 CFR 60.4245(a)(1))

2) Maintenance conducted on the engine. (40 CFR 60.4245(a)(2))

3) If the stationary SI internal combustion engine is a certified engine, documentation from the manufacturer that the engine is certified to

meet the emission standards and information as required in 40 CFR parts 90, 1048, 1054, and 1060, as applicable. (40 CFR 60.4245(a)(3))

4) If the stationary SI internal combustion engine is not a certified engine or is a certified engine operating in a non-certified manner and subject to 40 CFR 60.4243(a)(2), documentation that the engine meets the emission standards. (40 CFR 60.4245(a)(4))

v. The owner or operator of an emergency SI Internal Combustion Engine greater than 25 HP and less than 130 HP manufactured on or after July 1, 2008, that do not meet the standards applicable to non-emergency engines, the owner or operator of shall keep records of the operation of the engine in emergency and non-emergency service that are recorded through the non-resettable hour meter. The owner must record the time of operation of the engine and the reason the engine was in operation during that time. (40 CFR 60.4245(b))

b. **HAP**

For E36 and IE24: (condition i)

i. There are no compliance monitoring or record keeping requirements for HAP.

For E37: (condition ii)

ii. The owner or operator shall maintain records of the fuel MSDS sheets and receipts showing dates, amounts of fuel purchased, sulfur content of fuel purchased and supplier's name and address.

S3. **Reporting** (Regulation 2.16, section 4.1.9.3)

The owner or operator shall submit quarterly compliance reports that include the information in this section.

a. **Unit Operation**

For E36: (condition i)

i. The owner or operator is not required to submit an initial notification. (40 CFR 60.4214(b))

For IE24: (condition ii through iii)

ii. If you own or operate an emergency stationary SI ICE with a maximum engine power more than 100 HP (EG2 and EG3) that operates or is contractually obligated to be available for more than 15 hours per calendar year for the purposes specified in 40 CFR 60.4243(d)(2)(ii) and (iii) or that operates for the purposes specified in 40 CFR 60.4243(d)(3)(i), you must submit an annual report according to the requirements in paragraphs (e)(1) through (3) of this section. (40 CFR 60.4245(e))

1) The report must contain the following information: (40 CFR 60.4245(e)(1))

   (a) Company name and address where the engine is located. (40 CFR 60.4245(e)(1)(i))
   (b) Date of the report and beginning and ending dates of the reporting period. (40 CFR 60.4245(e)(1)(ii))
   (c) Engine site rating and model year. (40 CFR 60.4245(e)(1)(iii))
   (d) Latitude and longitude of the engine in decimal degrees reported to the fifth decimal place. (40 CFR 60.4245(e)(1)(iv))
   (e) Hours operated for the purposes specified in 40 CFR 60.4243(d)(2)(ii) and (iii), including the date, start time, and end time for engine operation for the purposes specified in 40 CFR 60.4243(d)(2)(ii) and (iii). (40 CFR 60.4245(e)(1)(v))
   (f) Number of hours the engine is contractually obligated to be available for the purposes specified in 40 CFR 60.4243(d)(2)(ii) and (iii). (40 CFR 60.4245(e)(1)(vi))
   (g) Hours spent for operation for the purposes specified in 40 CFR 60.4243(d)(3)(i), including the date, start time, and end time for engine operation for the purposes specified in 40 CFR 60.4243(d)(3)(i). The report must also identify the entity that dispatched the engine and the situation that necessitated the dispatch of the engine. (40 CFR 60.4245(e)(1)(vii))

2) The first annual report must cover the calendar year 2015 and must be submitted no later than March 31, 2016. Subsequent annual reports for each calendar year must be submitted no later than March 31 of the following calendar year. (40 CFR 60.4245(e)(2))

3) The annual report must be submitted electronically using the subpart specific reporting form in the Compliance and Emissions Data Reporting Interface (CEDRI) that is accessed through EPA's Central Data Exchange (CDX) (*www.epa.gov/cdx*). However, if the reporting form specific to this subpart is not available in CEDRI at the time that the report is due, the written report must be submitted

to the Administrator at the appropriate address listed in 40 CFR 60.4. (40 CFR 60.4245(e)(3))

iii. The owner or operator shall identify all periods of exceeding the hour limits during the reporting period. The compliance report shall include the following:

1) Identification of all periods during which a deviation occurred;
2) A description, including the magnitude, of the deviation;
3) If known, the cause of the deviation;
4) A description of all corrective actions taken to abate the deviation; and
5) If no deviations occur during a reporting period, the report shall contain a negative declaration.

b. **HAP**

For E36 and IE24: (condition i)

i. There are no routine compliance reporting requirements for this equipment.

For E37: (condition ii through iii)

ii. The owner or operator shall submit an Initial Notification not later than 120 days after become subject to 40 CFR 63, Subpart ZZZZ. (40 CFR 63.6645(c))

iii. If the owner or operator are required to submit an Initial Notification but are otherwise not affected by the requirements of this subpart, the notification should include the information in 40 CFR 63.9(b)(2)(i) through (v), and a statement that your stationary RICE has no additional requirements and explain the basis of the exclusion. (40 CFR 63.6645(f))

Emission Unit IA4: Two (2) fire pump engines[140]

IA4 Applicable Regulations:

FEDERALLY ENFORCEABLE REGULATIONS		
Regulation	**Title**	**Applicable Sections**
40 CFR 63, Subpart ZZZZ	National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines	63.6603, 6604, 6605, 6625, 6640, 6645, 6655
40 CFR 60, Subpart IIII	Standards of Performance for Stationary Compression Ignition Internal Combustion Engines	60.4200 - 4219

IA4 Equipment:[141,142]

Emission Point	Description	Applicable Regulation	Control ID	Stack ID
IE9	One (1) diesel fire pump engine, make Clarke, model JU4H-UFADY8, rated at 157 HP with a 187 gallon diesel fuel tank. [143,144]	40 CFR 63, Subpart ZZZZ, 40 CFR 60, Subpart IIII	N/A	N/A
IE10	One (1) diesel fire pump engine, make Clarke, model JU6H-UFADY58, rated at 183 HP with a 300 gallon diesel fuel tank.[143,144]			

IA4 Control Devices:

There are no control devices associated with this equipment.

[140] Per Regulation 5.21, section 2.3, emissions from insignificant activity are de minimis.

[141] The associated storage tank for diesel fuel is exempt from District permitting requirements in accordance with Regulation 1.02, section 3.9.2.

[142] Potential emissions for this permitted operation are greatest for nitrogen oxides (NOx). Based on AP-42 Emission Factors and 500 hours per year for an emergency generator, as defined by EPA, the potential NOx emissions for this permitted operation is less than 5 tons per year.

[143] This operation is subject to 40 CFR 63, Subpart ZZZZ, National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines, because it involves a stationary reciprocating internal combustion engine (RICE) located at a major source of HAP emissions. The proposed new stationary RICE meets the definition in 40 CFR 63.6675 of an emergency stationary RICE, which, per 40 CFR 63.6590(c), shall meet the requirements of 40 CFR 63, Subpart ZZZZ and 40 CFR 60, Subpart IIII.

[144] Fire pump engine is an emergency engine per 40 CFR 60, Subpart IIII, 60.4219, "Fire pump engine" means an emergency stationary internal combustion engine certified to NFPA requirements that is used to provide power to pump water for fire suppression or protection."

IA4 Specific Conditions

S1. **Standards** (Regulation 2.16, section 4.1.1)

a. **Unit Operation**

i. The owner or operator that must comply with the emission standards specified in 40 CFR 60, Subpart IIII shall do all of the following: (40 CFR 60.4211(a))

1) Operate and maintain the stationary CI internal combustion engine and control device according to the manufacturer's emission-related written instructions; (40 CFR 60.4211(a)(1))

2) Change only those emission-related settings that are permitted by the manufacturer; (40 CFR 60.4211(a)(2))

ii. The owner or operator shall purchase an engine certified to the emission standards in 40 CFR 60.4205(c), as applicable for the same model year and maximum engine power. The engine must be installed and configured according to the manufacturer's specifications. (40 CFR 60.4211(c))

iii. Engine manufacturers shall certify the fire pump stationary CI engines to the emission standards in table 4 to 40 CFR 60, Subpart IIII, for all pollutants, for the same model year and NFPA nameplate power. (40 CFR 60.4202(d))

Fire pump engines for this unit are subject to following emission standards in g/KW-hr (g/HP-hr): (Table 4 to 40 CFR 60, Subpart IIII)

Equipment Description	Model Year	NMHC+ NO_x	CO	PM
IE9: 157 HP fire pump	2013	4.0 (3.0)	N/A	0.30 (0.22)
IE10: 183 HP fire pump	2013	4.0 (3.0)	N/A	0.20 (0.15)

iv. In order for the engine to be considered an emergency stationary ICE under this subpart, any operation other than emergency operation, maintenance and testing, emergency demand response, and operation in non-emergency situations for 50 hours per year, as described in 40 CFR 60.4211(f)(1) through (3), is prohibited. If the owner or operator does not operate the engine according to the requirements in 40 CFR 60.4211(f)(1) through (3), the engine will not be considered an emergency engine under this subpart and must meet all requirements for non-emergency engines. (40 CFR 60.4211(f), 40 CFR 63.6640(f))

1) There is no time limit on the use of emergency stationary ICE in emergency situations. (40 CFR 60.4211(f)(1), 40 CFR 63.6640(f)(1))

2) The owner or operator may operate the emergency stationary ICE for any combination of the purposes specified in 40 CFR 60.4211(f)(2)(i) through (iii) for a maximum of 100 hours per calendar year. Any operation for non-emergency situations as allowed by 40 CFR 60.4211(f)(3) counts as part of the 100 hours per calendar year allowed by this paragraph. (40 CFR 60.4211(f)(2), 40 CFR 63.6640(f)(2)).

(a) Emergency stationary ICE may be operated for maintenance checks and readiness testing, provided that the tests are recommended by federal, state or local government, the manufacturer, the vendor, the regional transmission organization or equivalent balancing authority and transmission operator, or the insurance company associated with the engine. The owner or operator may petition the Administrator for approval of additional hours to be used for maintenance checks and readiness testing, but a petition is not required if the owner or operator maintains records indicating that federal, state, or local standards require maintenance and testing of emergency ICE beyond 100 hours per calendar year. (40 CFR 60.4211(f)(2)(i), 40 CFR 63.6640(f)(2)(i))

3) Emergency stationary ICE may be operated for up to 50 hours per calendar year in non-emergency situations. The 50 hours of operation in non-emergency situations are counted as part of the 100 hours per calendar year for maintenance and testing. (40 CFR 60.4211(f)(3), 40 CFR 63.6640(f)(3))

v. At all times the owner or operator shall operate and maintain any affected source, including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. The general duty to minimize emissions does not require the owner or operator to make any further efforts to reduce emissions if levels required by this standard have been achieved. Determination of whether such operation and maintenance procedures are being used will be based on information available to the Administrator which may include, but is not limited to, monitoring results, review of operation and maintenance procedures, review of operation and maintenance records, and inspection of the source. (40 CFR 63.6605(b))

b. **SO_2**

The owner or operator shall not combust in the engine a nonroad diesel fuel that contains more than 15 ppm of sulfur. (40 CFR 60.4207(b))
(40 CFR 80.510(b)(1)(i))

c. **HAP**

The equipment listed in this emission unit is subject to 40 CFR 63, Subpart ZZZZ, however, there are no HAP standards.

S2. **Monitoring and Record Keeping (** Regulation 2.16, sections 4.1.9.1 and 4.1.9.2**)**

The owner or operator shall maintain the required records for a minimum of 5 years and make the records readily available to the District upon request.

a. **Unit Operation**

The owner or operator is not required to submit an initial notification. The owner or operator shall keep records of the operation of the engine in emergency and non-emergency service that are recorded through the non-resettable hour meter. The owner must record the time of operation of the engine and the reason the engine was in operation during that time. (40 CFR 60.4214(b))

b. **SO_2**

The owner or operator shall maintain records of the fuel MSDS sheets and receipts showing dates, amounts of fuel purchased, sulfur content of fuel purchased and supplier’s name and address, to show compliance with Specific Condition S1.e.

c. **HAP**

There are no compliance monitoring or record keeping requirements for HAP.

S3. **Reporting** (Regulation 2.16, section 4.1.9.3)

The owner or operator shall submit quarterly compliance reports that include the information in this section.

a. **Unit Operation**

There are no routine compliance reporting requirements for this equipment.

b. **SO_2**

There are no routine compliance reporting requirements for this equipment.

c. **HAP**

There are no routine compliance reporting requirements for this equipment.

Emission Unit IA-OT: Other insignificant activities[145]

IA-OT Applicable Regulations:

FEDERALLY ENFORCEABLE REGULATIONS		
Regulation	**Title**	**Applicable Sections**
7.08	Standards of Performance for New Affected Facilities	1, 2, 3, 4, 5, 6
7.12	Standard of Performance for New Storage Vessels for Volatile Organic Compounds	1, 2, 3, 4, 5, 6, 7, 8

IA-OT Equipment:

Emission Point	Description	Applicable Regulation	Control ID	Stack ID
IE11	Seventeen (17) lubricating oil tanks, capacity ranged from 400 to 20,000 gallons, each has a vapor pressure less than 1.0 mmHg (< 0.019 psi)	7.12	N/A	N/A
IE12	One (1) 1,000 gallon storage tank for #1 fuel oil with annual turnover < 2X the capacity, vapor pressure less than 0.019 psi	7.12	N/A	N/A
IE13	One (1) portable kerosene storage tanks with capacity less than 500 gallons, vapor pressure less than 0.019 psi	7.12	N/A	N/A
IE14	Two (2) cooling towers for Unit 2 and Unit 3	7.08	N/A	N/A
IE15	One (1) gypsum handling equipment, including two (2) stackers, two (2) overland conveyors, one (1) barge loading, and one (1) truck loading	7.08	N/A	N/A
IE16	Two (2) portable gypsum dewatering systems, make SynMat, consist of two (2) belt filters, three (3) belt conveyors, and two (2) radial stacker (A and B)	7.08	N/A	N/A
IE17	One (1) bottom/fly ash storage silo equipped with bin vent filters, make and model TBD, rated capacity 325 tph.[146]	7.08	C40	S30
IE18	One (1) bottom/fly ash storage silo equipped with bin vent filters, make and model TBD, rated capacity 325 tph.[146]	7.08	C41	S31

[145] Per Regulation 5.21, section 2.3, emissions from insignificant activity are de minimis.

[146] A construction application for this equipment was submitted on 3/24/2017. The District has determined this is an insignificant activity per PTE, therefore no construction permit is required.

Emission Point	Description	Applicable Regulation	Control ID	Stack ID
IE19	One (1) pub mill mixers, make and model TBD, rated capacity 200 tph [146]	7.08	N/A	N/A
IE20	One (1) pub mill mixers, make and model TBD, rated capacity 200 tph [146]	7.08	N/A	N/A
IE21	One (1) pub mill mixers, make and model TBD, rated capacity 200 tph [146]	7.08	N/A	N/A
IE22	One (1) pub mill mixers, make and model TBD, rated capacity 200 tph [146]	7.08	N/A	N/A
IE23	One (1) process water system (PWS), including:			
	IE23-a: one (1) hydrated lime silos with bin vent filters, make and model TBD, rated capacity 10 tph;	7.08	C42-a	S32-a
	IE23-b: one (1) hydrated lime silos with bin vent filters, make and model TBD, rated capacity 10 tph;		C42-b	S32-b
	IE23-c: one (1) PWS solid material storage pile;		N/A	N/A
	IE23-d: one (1) front-end loader used to load material to trucks, capacity 20 tph.		N/A	N/A

IA-OT Control Devices:

ID	Description	Performance Indicator	Stack ID
C40	One (1) bin vent filter controlling ash storage silo	N/A[147]	S30
C41	One (1) bin vent filter controlling ash storage silo	N/A[147]	S31
C42-a	One (1) bin vent filter controlling PWS hydrated lime silos	N/A[147]	S32-a
C42-b	One (1) bin vent filter controlling PWS hydrated lime silos	N/A[147]	S32-b

[147] The bin vent filter equipped for each silo is considered as an integrated component of the silo. However, there are monitoring, record keeping and reporting requirements associated with any times that the filters are not in place and the process is operated.

IA-OT Specific Conditions

S1. **Standards** (Regulation 2.16, section 4.1.1)

a. **PM**

i. For cooling towers (IE14): The owner or operator shall not allow PM emissions to exceed 93.4 lb/hr for Unit 2 cooling tower and 98.2 lb/hr for Unit 3 cooling tower, based on actual operating hours in a calendar day.[148] (Regulation 7.08, section 3.1.2)

ii. For gypsum handling equipment (IE15): The owner or operator shall not allow PM emissions from all the gypsum handling equipment combined to exceed 36.2 lb/hr based on actual operating hours in a calendar day.[148] (Regulation 7.08, section 3.1.2)

iii. For gypsum dewatering system (IE16): The owner or operator shall not allow PM emissions from each gypsum system to exceed 30.1 lb/hr based on actual operating hours in a calendar day.[148] (Regulation 7.08, section 3.1.2)

iv. For ash storage silos (IE17 and IE18): The owner or operator shall not allow PM emissions from each silo to exceed 43.7 lb/hr based on actual operating hours in a calendar day.[148] (Regulation 7.08, section 3.1.2)

v. For ash storage silos (IE17 and IE18): The owner or operator shall maintain the bin vent filters in place at all times the process equipment is in operation, including periods of startup, shutdown, and malfunction, in a manner consistent with good air pollution control practice to meet the standards. (Regulation 2.16, section 4.1.1)

vi. For pug mill mixers (IE19, IE20, IE21, and IE22): The owner or operator shall not allow PM emissions from each pug mill mixer to exceed 40.41 lb/hr based on actual operating hours in a calendar day.[148] (Regulation 7.08, section 3.1.2)

vii. For hydrated lime silos (IE23-a and IE23-b): The owner or operator shall not allow PM emissions from each silo to exceed 14.97 lb/hr based on actual operating hours in a calendar day.[148] (Regulation 7.08, section 3.1.2)

viii. For PWS solid material storage pile (IE23-c) and front-end loader (IE23-d): The owner or operator shall not allow PM emissions from each silo to exceed 23.00 lb/hr based on actual operating hours in a calendar day.[148] (Regulation 7.08, section 3.1.2)

[148] It has been demonstrated that the PM emissions from this equipment cannot exceed the lb/hr PM standards uncontrolled.

b. **Opacity**

For ash storage silos and pug mill mixers (IE14-IE22), PWS (IE23): The owner or operator shall not allow visible emissions to equal or exceed 20% opacity. (Regulation 6.09, section 3.1) (Regulation 7.08, section 3.1.1)

c. **VOC**

For storage tanks (IE11, IE12, and IE13):

The owner or operator shall not store materials with an as stored vapor pressure of greater than or equal to 1.5 psia in the storage vessel(s), unless the storage tank is equipped with a permanent submerged fill pipe. (Regulation 7.12, section 3.3)

S2. **Monitoring and Record Keeping** (Regulation 2.16, sections 4.1.9.1 and 4.1.9.2)

The owner or operator shall maintain the required records for a minimum of 5 years and make the records readily available to the District upon request.

a. **PM**

i. There are no monitoring and record keeping requirements for IE14, IE15, and IE16.

ii. For ash storage silos and pug mill mixers (IE17-IE22), hydrated lime silos (IE23-a and IE23-b):

1) The owner or operator shall maintain monthly records of the type and amount of material throughput for each piece of equipment.

iii. For ash storage silos (IE17 and IE18), hydrated lime silos (IE23-a and IE23-b):

1) The owner or operator shall monthly perform a visual inspection of the structural and mechanical integrity of the bin vent filters for signs of damage, air leakage, corrosion, or other equipment defects, and repair and/or replace defective components as needed. The owner or operator shall maintain monthly records of the results.

2) The owner or operator shall maintain daily records of any periods of time where the process was operating and the bin vent filters were not in place or a declaration that the bin vent filters were in place at all times that day when the process was operating.

3) If there is any time that the bin vent filters are not in place when the process is operating, then the owner or operator shall keep a record of the following for each bypass event:

(a) Date;
(b) Start time and stop time;
(c) Identification of the bin vent filters and process equipment;
(d) PM emissions during the bypass in lb/hr;
(e) Summary of the cause or reason for each bypass event;
(f) Corrective action taken to minimize the extent or duration of the bypass event; and
(g) Measures implemented to prevent reoccurrence of the situation that resulted in the bypass event.

b. **Opacity**

i. There are no monitoring and record keeping requirements for IE14, IE15, and IE16.

ii. For ash storage silos and pug mill mixers (IE17-IE22), <u>PWS (IE23)</u>:

1) The owner or operator shall conduct a monthly one-minute visible emissions survey, during normal operation, of the emission points. No more than four emission points shall be observed simultaneously. The opacity surveys can be performed on the building exhaust points if the process is inside an enclosure.

2) At emission points where visible emissions are observed, the owner or operator shall initiate corrective action within eight hours of the initial observation. If correction actions are taken then a follow-up visible emission survey shall be made. If the visible emissions persist, the owner or operator shall perform or cause to be performed a Method 9, in accordance with 40 CFR Part 60, Appendix A, 24 hours of the initial observation.

c. **VOC**

<u>For storage tanks (IE11, IE12, and IE13):</u>

The owner or operator of the storage vessel(s) shall maintain records of the material stored and the vapor pressure in each storage vessel and if the contents of the storage vessel(s) are changed a record shall be made of the new contents, the date of the change, and the new vapor pressure.

S3. **Reporting** (Regulation 2.16, section 4.1.9.3)

a. **PM**

i. There are no reporting requirements for IE14, IE15, IE16, IE19, IE20, IE21, and IE22.

ii. For ash storage silos (IE17 and IE18), hydrated lime silos (IE23-a and IE23-b): The owner or operator shall report the following information regarding PM By-Pass Activity in the quarterly compliance reports.

1) Number of times the PM vent stream by-passes the bin vent filters and is vented to the atmosphere;
2) Duration of each by-pass to the atmosphere;
3) Calculated pound per hour PM emissions for each by-pass; or
4) A negative declaration if no by-passes occurred.

b. **Opacity**

i. There are no reporting requirements for IE14, IE15, and IE16.

ii. For ash storage silos and pug mill mixers (IE17-IE22), PWS (IE23): The owner or operator shall identify all periods of exceeding an opacity standard during a quarterly reporting period. The report shall include the following:

1) Any deviation from the requirement to perform daily (or monthly, if required) visible emission surveys or Method 9 tests;
2) Any deviation from the requirement to record the results of each VE survey and Method 9 test performed;
3) The date and time of each VE Survey where visible emissions were observed and the results of any Method 9 test performed;
4) The date, time and results of follow-up VE survey;
5) The date, time, and results of any Method 9 test performed;
6) Identification of all periods of exceeding an opacity standard; and
7) If no deviations occur during a quarterly reporting period, the report shall contain a negative declaration.

c. VOC

For storage tanks (IE11, IE12, and IE13):

There are no reporting requirements for this pollutant.

Attachment A - 40 CFR 63, Subpart UUUUU (MACT)[149]

The owner or operator shall comply with the following requirements unless there are more current promulgated regulations:

Specific Conditions

S1. **Standards (Regulation 2.16, section 4.1.1)**

HAP

i. Compliance date: (40 CFR 63.9984)

1) Unit U1, U2, U3, and U4 are existing EGUs according to 40 CFR 63.9982(d), therefore the owner or operator shall comply with 40 CFR 63, Subpart UUUUU no later than April 16, 2016.[150] (40 CFR 63.9984(b))

2) The owner or operator shall meet the notification requirements in 40 CFR63.10030 according to the schedule in 40 CFR63.10030 and in subpart A of this part (i.e., 40 CFR 63). Some of the notifications must be submitted before the owner or operator is required to comply with the emission limits and work practice standards in 40 CFR 63, Subpart UUUUU. (40 CFR 63.9984(c))

3) The owner or operator shall demonstrate that compliance has been achieved, by conducting the required performance tests and other activities, no later than 180 days after the compliance date. (40 CFR 63.9984(f))

ii. Emission limitations, work practice standards, and operating limits: (40 CFR 63.9991)

1) The owner or operator shall meet the requirements in the following paragraphs. The owner or operator shall meet these requirements at all times. (40 CFR 63.9991(a))

(a) The owner or operator shall meet each emission limit and work practice standard in Table 1 through 3 to 40 CFR 63, Subpart UUUUU that applies to the EGU, for each EGU at the source, except as provided under 40 CFR63.10009. (40 CFR 63.9991(a)(1))

[149] 40 CFR 60, Subpart UUUUU is revised according to Federal Register 81 FR 20172, 4/6/2016.

[150] According to 40 CFR 63.9984(b), the compliance date for an existing EGU is April 16, 2015. LG&E requested a year extension and the District has approved the request for the extension per (40 CFR 63.6(i)(4)(i)). Therefore the compliance date for the EGUs under this construction is April 16, 2016.

Table 2 to Subpart UUUUU of Part 63 - Emission Limits for Existing EGUs [As stated in 40 CFR63.9991. The owner or operator shall comply with the following applicable emission limits][1] (Modified to include requirements for LG&E only)

If the EGU is in this subcategory	For the following pollutants	The owner or operator shall meet the following emission limits and work practice standards	Using these requirements, as appropriate (e.g., specified sampling volume or test run duration) and limitations with the test methods in Table 5
1. Coal-fired unit not low rank virgin coal	a. Filterable particulate matter (PM) …	3.0E–2 lb/MMBtu or 3.0E–1 lb/MWh [2] …	Collect a minimum of 1 dscm per run.
	OR Total non-Hg HAP metals …	OR 5.0E–5 lb/MMBtu or 5.0E–1 lb/GWh …	Collect a minimum of 1 dscm per run.
	OR Individual HAP metals		
	Antimony (Sb) …	8.0E–1 lb/TBtu or 8.0E–3 lb/GWh …	
	Arsenic (As) …	1.1E0 lb/TBtu or 2.0E–2 lb/GWh …	
	Beryllium (Be) …	2.0E–1 lb/TBtu or 2.0E–3 lb/GWh …	
	Cadmium (Cd) …	3.0E–1 lb/TBtu or 3.0E–3 lb/GWh …	
	Chromium (Cr) …	2.8E0 lb/TBtu or 3.0E–2 lb/GWh …	
	Cobalt (Co) …	8.0E–1 lb/TBtu or 8.0E–3 lb/GWh …	
	Lead (Pb) …	1.2E0 lb/TBtu or 2.0E–2 lb/GWh …	
	Manganese (Mn) …	4.0E0 lb/TBtu or 5.0E–2 lb/GWh …	
	Nickel (Ni) …	3.5E0 lb/TBtu or 4.0E–2 lb/GWh …	
	Selenium (Se) …	5.0E0 lb/TBtu or 6.0E–2 lb/GWh …	
	b. Hydrogen chloride (HCl) …	2.0E–3 lb/MMBtu or 2.0E–2 lb/MWh …	For Method 26A, collect a minimum of 0.75 dscm per run; for Method 26, collect a minimum of 120 liters per run. For ASTM D6348–03 [3] or method 320, sample for a minimum of 1 hour.

If the EGU is in this subcategory	For the following pollutants	The owner or operator shall meet the following emission limits and work practice standards	Using these requirements, as appropriate (e.g., specified sampling volume or test run duration) and limitations with the test methods in Table 5
	OR Sulfur dioxide (SO_2)[151] as a surrogate for HCl	2.0E–1 lb/MMBtu or 1.5E0 lb/MWh …	SO2 CEMS
	c. Mercury (Hg) …	1.2E0 lb/TBtu or 1.3E–2 lb/GWh …	LEE Testing for 30 days with a sampling period consistent with that given in section 5.2.1 of appendix A to this subpart per Method 30B at appendix A-8 to part 60 of this chapter run or Hg CEMS or sorbent trap monitoring system only

1. For LEE emissions testing for total PM, total HAP metals, individual HAP metals, HCl, and HF, the required minimum sampling volume must be increased nominally by a factor of two.
2. Gross output.
3. Incorporated by reference, see 40 CFR 63.14.

Table 3 to Subpart UUUUU of Part 63 - Work Practice Standards[152] [As stated in 40 CFR 63.9991. The owner or operator shall comply with the following ap plicable work practice standards] (Modified to include requirements for LG&E only)

If the EGU is ...	The owner or operator shall meet the following . . .
1. An existing EGU …	Conduct a tune-up of the EGU burner and combustion controls at least each 36 calendar months, or each 48 calendar months if neural network combustion optimization software is employed, as specified in 40 CFR 63.10021(e).
3. A coal-fired, liquid oil-fired, or solid oil-derived fuel-fired EGU during startup …	a. You have the option of complying using either of the following work practice standards: (1) If you choose to comply using paragraph (1) of the definition of “startup” in § 63.10042, you must operate all CMS during startup. Startup means either the first-ever firing of fuel in a boiler for the purpose of producing electricity, or the firing of fuel in a boiler after a shutdown event for any purpose. Startup ends when any of the steam from the boiler is used to generate electricity for sale over the grid or for any other purpose (including on site use). For startup of a unit, you must use clean fuels as defined in § 63.10042 for ignition. Once you convert to firing coal, residual oil, or solid oil-derived fuel, you must engage all of the applicable control technologies except dry scrubber and SCR. You must start your dry scrubber and SCR systems, if present, appropriately to

[151] In a letter dated 7/21/2014, LG&E elected to comply with the alternate SO_2 limit with use of wet FGD and SO_2 CEMS.

[152] In this table, the work practice standards during startup and shutdown apply only to MATS.

If the EGU is ...	The owner or operator shall meet the following . . .
	comply with relevant standards applicable during normal operation. You must comply with all applicable emissions limits at all times except for periods that meet the applicable definitions of startup and shutdown in this subpart. You must keep records during startup periods. You must provide reports concerning activities and startup periods, as specified in § 63.10011(g) and § 63.10021(h) and (i). (2) If you choose to comply using paragraph (2) of the definition of "startup" in § 63.10042, you must operate all CMS during startup. You must also collect appropriate data, and you must calculate the pollutant emission rate for each hour of startup. For startup of an EGU, you must use one or a combination of the clean fuels defined in § 63.10042 to the maximum extent possible, taking into account considerations such as boiler or control device integrity, throughout the startup period. You must have sufficient clean fuel capacity to engage and operate your PM control device within one hour of adding coal, residual oil, or solid oil-derived fuel to the unit. You must meet the startup period work practice requirements as identified in § 63.10020(e). Once you start firing coal, residual oil, or solid oil-derived fuel, you must vent emissions to the main stack(s). You must comply with the applicable emission limits beginning with the hour after startup ends. You must engage and operate your particulate matter control(s) within 1 hour of first firing of coal, residual oil, or solid oil-derived fuel. You must start all other applicable control devices as expeditiously as possible, considering safety and manufacturer/supplier recommendations, but, in any case, when necessary to comply with other standards made applicable to the EGU by a permit limit or a rule other than this Subpart that require operation of the control devices. b. Relative to the syngas not fired in the combustion turbine of an IGCC EGU during startup, you must either: (1) Flare the syngas, or (2) route the syngas to duct burners, which may need to be installed, and route the flue gas from the duct burners to the heat recovery steam generator. c. If you choose to use just one set of sorbent traps to demonstrate compliance with the applicable Hg emission limit, you must comply with the limit at all times; otherwise, you must comply with the applicable emission limit at all times except for startup and shutdown periods. d. You must collect monitoring data during startup periods, as specified in § 63.10020(a) and (e). You must keep records during startup periods, as provided in § § 63.10032 and 63.10021(h). You must provide reports concerning activities and startup periods, as specified in § § 63.10011(g), 63.10021(i), and 63.10031.
4. A coal-fired, liquid oil-fired, or solid oil-derived fuel-fired EGU during shutdown …	You must operate all CMS during shutdown. You must also collect appropriate data, and you must calculate the pollutant emission rate for each hour of shutdown for those pollutants for which a CMS is used. While firing coal, residual oil, or solid oil-derived fuel during shutdown, you must vent emissions to the main stack(s) and operate all applicable control devices and continue to operate those control devices after the cessation of coal, residual oil, or solid oil-derived fuel being fed into the

If the EGU is ...	The owner or operator shall meet the following . . .
	EGU and for as long as possible thereafter considering operational and safety concerns. In any case, you must operate your controls when necessary to comply with other standards made applicable to the EGU by a permit limit or a rule other than this Subpart and that require operation of the control devices. If, in addition to the fuel used prior to initiation of shutdown, another fuel must be used to support the shutdown process, that additional fuel must be one or a combination of the clean fuels defined in § 63.10042 and must be used to the maximum extent possible, taking into account considerations such as not compromising boiler or control device integrity. Relative to the syngas not fired in the combustion turbine of an IGCC EGU during shutdown, you must either: (1) Flare the syngas, or (2) route the syngas to duct burners, which may need to be installed, and route the flue gas from the duct burners to the heat recovery steam generator. You must comply with all applicable emission limits at all times except during startup periods and shutdown periods at which time you must meet this work practice. You must collect monitoring data during shutdown periods, as specified in § 63.10020(a). You must keep records during shutdown periods, as provided in § § 63.10032 and 63.10021(h). Any fraction of an hour in which shutdown occurs constitutes a full hour of shutdown. You must provide reports concerning activities and shutdown periods, as specified in § § 63.10011(g), 63.10021(i), and 63.10031.

(b) The owner or operator shall meet each operating limit in Table 4 to 40 CFR 63, Subpart UUUUU that applies to the EGU. (40 CFR 63.9991(a)(2))

Table 4 to Subpart UUUUU of Part 63 - Operating Limits for EGUs [As stated in 40 CFR63.9991. The owner or operator shall comply with the applicable operating limits]

If the owner or operator demonstrates compliance using ...	The owner or operator shall meet these operating limits ...
1. PM CPMS …	Maintain the 30–boiler operating day rolling average PM CPMS output determined in accordance with the requirements of 40 CFR 63.10023(b)(2) and obtained during the most recent performance test demonstrating compliance with the filterable PM, total non-mercury HAP metals (total HAP metals, for liquid oil fired units), or individual non-mercury HAP metals (individual HAP metals including Hg, for liquid oil-fired units) emissions limitation(s).

2) As provided in 40 CFR63.6(g), the Administrator may approve use of an alternative to the work practice standards in this section. (40 CFR 63.9991(b))

3) The owner or operator may use the alternate SO_2 limit in Tables 1 and 2 to 40 CFR 63, Subpart UUUUU only if the EGU: (40 CFR 63.9991(c))

(a) Has a system using wet or dry flue gas desulfurization technology and SO_2 continuous emissions monitoring system (CEMS) installed on the EGU; and (40 CFR 63.9991(c)(1))

(b) At all times, the owner or operator operates the wet or dry flue gas desulfurization technology and the SO_2 CEMS installed on the unit consistent with 40 CFR 63.10000(b). (40 CFR 63.9991(c)(2))

iii. General requirements for complying with 40 CFR 63, Subpart UUUUU: (40 CFR 63.10000)

1) The owner or operator shall be in compliance with the emission limits and operating limits in 40 CFR 63, Subpart UUUUU. These limits apply to the owner or operator at all times except during periods of startup and shutdown; however, for coal-fired, liquid oil-fired, or solid oil-derived fuel-fired EGUs, the owner or operator is required to meet the work practice requirements, items 3 and 4, in Table 3 to 40 CFR 63, Subpart UUUUU during periods of startup or shutdown. (40 CFR 63.10000(a))

2) At all times the owner or operator shall operate and maintain any affected source, including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. Determination of whether such operation and maintenance procedures are being used will be based on information available to the EPA Administrator which may include, but is not limited to, monitoring results, review of operation and maintenance procedures, review of operation and maintenance records, and inspection of the source. (40 CFR 63.10000(b))

3) For coal-fired units, solid oil-derived fuel-fired units, and IGCC EGUs, initial performance testing is required for all pollutants, to demonstrate compliance with the applicable emission limits. (40 CFR 63.10000(c)(1))

(a) For a coal-fired or solid oil-derived fuel-fired EGU or IGCC EGU, the owner or operator may conduct the initial performance testing in accordance with 40 CFR63.10005(h), to determine whether the EGU qualifies as a low emitting EGU (LEE) for one or more applicable emissions limits, except as otherwise provided in paragraphs (c)(1)(i)(A) and (B) of this section: (40 CFR 63.10000(c)(1)(i))

(i) Except as provided in paragraph (c)(1)(i)(C) of this section, the owner or operator may not pursue the LEE option if the coal-fired, IGCC, or solid oil-derived fuel-fired EGU is equipped with a main stack and bypass stack or bypass duct configuration that allows the effluent to bypass any pollutant control device. (40 CFR 63.10000(c)(1)(i)(A))

(ii) The owner or operator may not pursue the LEE option for Hg if the coal-fired, solid oil-derived fuel fired EGU or IGCC EGU is new. (40 CFR 63.10000(c)(1)(i)(B))

(iii) The owner or operator may pursue the LEE option provided that: (40 CFR 63.10000(c)(1)(i)(C))

(A) The owner or operator’s EGU's control device bypass emissions are measured in the bypass stack or duct or your control device bypass exhaust is routed through the EGU main stack so that emissions are measured during the bypass event; or (40 CFR 63.10000(c)(1)(i)(C)(1))

(B) Except for hours during which only clean fuel is combusted, you bypass your EGU control device only during emergency periods for no more than a total of 2 percent of your EGU's annual operating hours; you use clean fuels to the maximum extent possible during an emergency period; and you prepare and submit a report describing the emergency event, its cause, corrective action taken, and estimates of emissions released during the emergency event. The owner or operator shall include these emergency emissions along with performance test results in assessing whether your EGU maintains LEE status. (40 CFR 63.10000(c)(1)(i)(C)(2))

(b) For a qualifying LEE for Hg emissions limits, the owner or operator shall conduct a 30–day performance test using Method 30B at least once every 12 calendar months to demonstrate continued LEE status. (40 CFR 63.10000(c)(1)(ii))

(c) For a qualifying LEE of any other applicable emissions limits, the owner or operator shall conduct a performance test at least once every 36 calendar months to demonstrate continued LEE status. (40 CFR 63.10000(c)(1)(iii))

(d) If the coal-fired or solid oil-derived fuel-fired EGU or IGCC EGU does not qualify as a LEE for total non-mercury HAP metals, individual non-mercury HAP metals, or filterable particulate matter (PM), the owner or operator shall demonstrate compliance through an initial performance test and the owner or operator shall monitor continuous performance through either use of a particulate matter continuous parametric monitoring system (PM CPMS), a PM CEMS, or for an existing EGU compliance performance testing repeated quarterly. (40 CFR 63.10000(c)(1)(iv))

(e) If the coal-fired or solid oil-derived fuel-fired EGU does not qualify as a LEE for hydrogen chloride (HCl), the owner or operator may demonstrate initial and continuous compliance through use of an HCl CEMS, installed and operated in accordance with Appendix B to 40 CFR 63, Subpart UUUUU. As an alternative to HCl CEMS, the owner or operator may demonstrate initial and continuous compliance by conducting an initial and periodic quarterly performance stack test for HCl. If the EGU uses wet or dry flue gas desulfurization technology (this includes limestone injection into a fluidized bed combustion unit), the owner or operator may apply a second alternative to HCl CEMS by installing and operating a sulfur dioxide (SO_2) CEMS installed and operated in accordance with part 75 of this chapter to demonstrate compliance with the applicable SO_2 emissions limit. (40 CFR 63.10000(c)(1)(v))

(f) If the coal-fired or solid oil-derived fuel-fired EGU does not qualify as a LEE for Hg, the owner or operator shall demonstrate initial and continuous compliance through use of a Hg CEMS or a sorbent trap monitoring system, in accordance with appendix A to 40 CFR 63, Subpart UUUUU. (40 CFR 63.10000(c)(1)(vi))

4) Site-specific monitoring plan:

(a) If the owner or operator demonstrates compliance with any applicable emissions limit through use of a continuous monitoring system (CMS), where a CMS includes a continuous parameter monitoring system (CPMS) as well as a continuous emissions monitoring system (CEMS), the owner or operator shall develop a site-specific monitoring plan and submit this site-specific monitoring plan, if requested, at least 60 days before the initial performance evaluation (where applicable) of the CMS. This requirement also applies to the owner or operator if the owner or operator petitions the Administrator for alternative monitoring parameters under 40 CFR63.8(f). This requirement to develop and submit a site-specific monitoring plan does not apply to affected sources with existing monitoring plans that apply to CEMS and CPMS prepared under Appendix B to part 60 or part 75 of this chapter, and that meet the requirements of 40 CFR63.10010. Using the process described in 40 CFR63.8(f)(4), the owner or operator may request approval of monitoring system quality assurance and quality control procedures alternative to those specified in this paragraph of this section and, if approved, include those in the site-specific monitoring plan. The monitoring plan must address the provisions in paragraphs (d)(2) through (5) of this section. (40 CFR 63.10000(d)(1))

(b) The site-specific monitoring plan shall include the information specified in paragraphs (d)(5)(i) through (d)(5)(vii) of this section. Alternatively, the requirements of paragraphs (d)(5)(i) through (d)(5)(vii) are considered to be met for a particular CMS or sorbent trap monitoring system if: (40 CFR 63.10000(d)(2))

(i) The CMS or sorbent trap monitoring system is installed, certified, maintained, operated, and quality-assured either according to part 75 of this chapter, or appendix A or B to 40 CFR 63, Subpart UUUUU; and (40 CFR 63.10000(d)(2)(i))

(ii) The recordkeeping and reporting requirements of part 75 of this chapter, or appendix A or B to 40 CFR 63, Subpart UUUUU, that pertain to the CMS are met. (40 CFR 63.10000(d)(2)(ii))

(c) If requested by the Administrator, the owner or operator shall submit the monitoring plan (or relevant portion of the plan) at least 60 days before the initial performance evaluation of a particular CMS, except where the CMS has already undergone a performance evaluation that meets the requirements of 40 CFR63.10010 (e.g., if the CMS was previously certified under another program). (40 CFR 63.10000(d)(3))

(d) The owner or operator shall operate and maintain the CMS according to the site-specific monitoring plan. (40 CFR 63.10000(d)(4))

(e) The provisions of the site-specific monitoring plan must address the following items: (40 CFR 63.10000(d)(5))

(i) Installation of the CMS or sorbent trap monitoring system sampling probe or other interface at a measurement location relative to each affected process unit such that the measurement is representative of control of the exhaust emissions (e.g., on or downstream of the last control device). See 40 CFR63.10010(a) for further details. For PM CPMS installations, follow the procedures in 40 CFR63.10010(h). (40 CFR 63.10000(d)(5)(i))

(ii) Performance and equipment specifications for the sample interface, the pollutant concentration or parametric signal analyzer, and the data collection and reduction systems. (40 CFR 63.10000(d)(5)(ii))

(iii) Schedule for conducting initial and periodic performance evaluations. (40 CFR 63.10000(d)(5)(iii))

(iv) Performance evaluation procedures and acceptance criteria (e.g., calibrations), including quality control program in accordance with the general requirements of 40 CFR63.8(d). (40 CFR 63.10000(d)(5)(iv))

(v) On-going operation and maintenance procedures, in accordance with the general requirements of 40 CFR63.8(c)(1)(ii), (c)(3), and (c)(4)(ii). (40 CFR 63.10000(d)(5)(v))

(vi) Conditions that define a CMS that is out of control consistent with 40 CFR63.8(c)(7)(i) and for responding to out of control periods consistent with 40 CFR63.8(c)(7)(ii) and (c)(8). (40 CFR 63.10000(d)(5)(vi))

(vii) On-going recordkeeping and reporting procedures, in accordance with the general requirements of 40 CFR63.10(c), (e)(1), and (e)(2)(i), or as specifically required under 40 CFR 63, Subpart UUUUU. (40 CFR 63.10000(d)(5)(vii))

5) As part of the demonstration of continuous compliance, the owner or operator shall perform periodic tune-ups of the EGU(s), according to 40 CFR63.10021(e). (40 CFR 63.10000(e))

iv. General Provisions: (40 CFR 63.10040)

Table 9 to 40 CFR 63, Subpart UUUUU shows which parts of the General Provisions in 40 CFR63.1 through 63.15 apply to the owner or operator.

Table 9 to Subpart UUUUU of Part 63 – Applicability of General Provisions to Subpart UUUUU [As stated in 40 CFR63.10040. The owner or operator shall comply with the applicable General Provisions according to the following]

Citation	Subject	Applies to subpart UUUUU
40 CFR 63.1	Applicability	Yes.
40 CFR 63.2	Definitions	Yes. Additional terms defined in 40 CFR 63.10042.
40 CFR 63.3	Units and Abbreviations	Yes.
40 CFR 63.4	Prohibited Activities and Circumvention	Yes.
40 CFR 63.5	Preconstruction Review and Notification Requirements	Yes.
40 CFR 63.6(a), (b)(1)-(b)(5), (b)(7), (c), (f)(2)-(3), (g), (h)(2)-(h)(9), (i), (j)	Compliance with Standards and Maintenance Requirements	Yes.
40 CFR 63.6(e)(1)(i)	General Duty to minimize emissions	No. See 40 CFR 63.10000(b) for general duty requirement.
40 CFR 63.6(e)(1)(ii)	Requirement to correct malfunctions ASAP	No.
40 CFR 63.6(e)(3)	SSM Plan requirements	No.
40 CFR 63.6(f)(1)	SSM exemption	No.
40 CFR 63.6(h)(1)	SSM exemption	No.
40 CFR 63.7(a), (b), (c), (d), (e)(2)-(e)(9), (f), (g), and (h)	Performance Testing Requirements	Yes.

Citation	Subject	Applies to subpart UUUUU
40 CFR 63.7(e)(1)	Performance testing	No. See 40 CFR 63.10007.
40 CFR 63.8	Monitoring Requirements	Yes.
63.8(c)(1)(i)	General duty to minimize emissions and CMS operation	No. See 40 CFR 63.10000(b) for general duty requirement.
40 CFR 63.8(c)(1)(iii)	Requirement to develop SSM Plan for CMS	No.
40 CFR 63.8(d)(3)	Written procedures for CMS	Yes, except for last sentence, which refers to an SSM plan. SSM plans are not required.
40 CFR 63.9	Notification requirements	Yes, except (1) for the 60-day notification prior to conducting a performance test in 40 CFR 63.9(e); instead use a 30-day notification period per 40 CFR 63.10030(d). (2) the notification of the CMS performance evaluation in 40 CFR 63.9(g)(1) is limited to RATAs, and (3) the information required per 40 CFR 63.9(h)(2)(i); instead provide the information required per 40 CFR 63.10030(e)(1) through (e)(6) and (e)(8).
40 CFR 63.10(a), (b)(1), (c), (d)(1)-(2), (e), and (f)	Recordkeeping and Reporting Requirements	Yes, except for the requirements to submit written reports under 40 CFR 63.10(e)(3)(v).
40 CFR 63.10(b)(2)(i)	Recordkeeping of occurrence and duration of startups and shutdowns	No.
40 CFR 63.10(b)(2)(ii)	Recordkeeping of malfunctions	No. See 63.10001 for recordkeeping of (1) occurrence and duration and (2) actions taken during malfunction.
40 CFR 63.10(b)(2)(iii)	Maintenance records	Yes.
40 CFR 63.10(b)(2)(iv)	Actions taken to minimize emissions during SSM	No.
40 CFR 63.10(b)(2)(v)	Actions taken to minimize emissions during SSM	No.
40 CFR 63.10(b)(2)(vi)	Recordkeeping for CMS malfunctions	Yes.
40 CFR 63.10(b)(2)(vii)-(ix)	Other CMS requirements	Yes.

Citation	Subject	Applies to subpart UUUUU
40 CFR 63.10(b)(3),and (d)(3)-(5)		No.
40 CFR 63.10(c)(7)	Additional recordkeeping requirements for CMS—identifying exceedances and excess emissions	Yes.
40 CFR 63.10(c)(8)	Additional recordkeeping requirements for CMS—identifying exceedances and excess emissions	Yes.
40 CFR 63.10(c)(10)	Recording nature and cause of malfunctions	No. See 63.10032(g) and (h) for malfunctions recordkeeping requirements.
40 CFR 63.10(c)(11)	Recording corrective actions	No. See 63.10032(g) and (h) for malfunctions recordkeeping requirements.
40 CFR 63.10(c)(15)	Use of SSM Plan	No.
40 CFR 63.10(d)(5)	SSM reports	No. See 63.10021(h) and (i) for malfunction reporting requirements.
40 CFR 63.11	Control Device Requirements	No.
40 CFR 63.12	State Authority and Delegation	Yes.
40 CFR 63.13-63.16	Addresses, Incorporation by Reference, Availability of Information, Performance Track Provisions	Yes.
40 CFR 63.1(a)(5), (a)(7)-(a)(9), (b)(2), (c)(3)-(4), (d), 63.6(b)(6), (c)(3), (c)(4), (d), (e)(2), (e)(3)(ii), (h)(3), (h)(5)(iv), 63.8(a)(3), 63.9(b)(3), (h)(4), 63.10(c)(2)-(4), (c)(9)	Reserved	No.

S2. **Monitoring and Record Keeping (Regulation 2.16, sections 4.1.9.1 and 4.1.9.2)**

HAP

Testing and Initial Compliance Requirements:

i. Initial compliance requirements and date to conduct performance tests: (40 CFR 63.10005)

1) General requirements: For each of the affected EGUs, the owner or operator shall demonstrate initial compliance with each applicable emissions limit in Table 1 or 2 of 40 CFR 63, Subpart UUUUU through performance testing. Where two emissions limits are specified for a particular pollutant (e.g., a heat input based limit in lb/MMBtu and an electrical output-based limit in lb/MWh), the owner or operator may demonstrate compliance with either emission limit. For a particular compliance demonstration, the owner or operator may be required to conduct one or more of the following activities in conjunction with performance testing: collection of data, e.g., hourly gross output data (megawatts); establishment of operating limits according to 40 CFR 63.10011 and Tables 4 and 7 to 40 CFR 63, Subpart UUUUU; and CMS performance evaluations. In all cases, the owner or operator shall demonstrate initial compliance no later than the date in paragraph (f) of this section for tune-up work practices for existing EGUs; the date that compliance must be demonstrated, as given in § 63.9984 for other requirements for existing EGUs; and in paragraph (g) of this section for all requirements for new EGUs. (40 CFR 63.10005(a))

(a) To demonstrate initial compliance with an applicable emissions limit in Table 1 or 2 to 40 CFR 63, Subpart UUUUU using stack testing, the initial performance test generally consists of three runs at specified process operating conditions using approved methods. If the owner or operator is required to establish operating limits (see paragraph (d) of this section and Table 4 to 40 CFR 63, Subpart UUUUU), the owner or operator shall collect all applicable parametric data during the performance test period. Also, if the owner or operator chooses to comply with an electrical output-based emission limit, the owner or operator shall collect hourly gross output data during the test period. (40 CFR 63.10005(a)(1))

(b) To demonstrate initial compliance using either a CMS that measures HAP concentrations directly (i.e., an Hg, HCl, or HF CEMS, or a sorbent trap monitoring system) or an SO_2 or PM CEMS, the initial performance test consists of 30- or, for certain coal-fired existing EGUs that use emissions averaging for Hg, 90- boiler operating days. If the CMS is certified prior to the compliance date (or, if applicable, the approved extended compliance date), the test shall begin with the first operating day on or after that date, except as otherwise provided in paragraph (b) of this section. If the CMS is not certified prior to the compliance date, the test shall begin with the first operating day after certification testing is successfully completed. In all cases, the initial 30- or 90- operating day averaging period must be completed on or before the date that compliance must be demonstrated (i.e., 180 days after the applicable compliance date). (40 CFR 63.10005(a)(2))

(i) The CMS performance test must demonstrate compliance with the applicable Hg, HCl, HF, PM, or SO_2 emissions limit in Table 1 or 2 to 40 CFR 63, Subpart UUUUU. (40 CFR 63.10005(a)(2)(i))

(ii) The owner or operator shall collect hourly data from auxiliary monitoring systems (i.e., stack gas flow rate, CO_2, O_2, or moisture, as applicable) during the performance test period, in order to convert the pollutant concentrations to units of the standard. If you choose to comply with a gross output-based emission limit, you must also collect hourly gross output data during the performance test period. (40 CFR 63.10005(a)(2)(ii))

(iii) For a group of affected units that are in the same subcategory, are subject to the same emission standards, and share a common stack, if you elect to demonstrate compliance by monitoring emissions at the common stack, startup and shutdown emissions (if any) that occur during the 30-(or, if applicable, 90-) boiler operating day performance test must either be excluded from or included in the compliance demonstration as follows: (40 CFR 63.10005(a)(2)(iii))

(A) If one of the units that shares the stack either starts up or shuts down at a time when none of the other units is operating, you must exclude all pollutant emission rates measured during the startup or shutdown period, unless you are using a sorbent trap monitoring system to measure Hg emissions and have elected to include startup and shutdown emissions in the compliance demonstrations; (40 CFR 63.10005(a)(2)(iii)(A))

(B) If all units that are currently operating are in the startup or shutdown mode, you must exclude all pollutant emission rates measured during the startup or shutdown period, unless you are using a sorbent trap monitoring system to measure Hg emissions and have elected to include startup and shutdown emissions in the compliance demonstrations; or (40 CFR 63.10005(a)(2)(iii)(B))

(C) If any unit starts up or shuts down at a time when another unit is operating, and the other unit is not in the startup or shutdown mode, you must include all pollutant emission rates measured during the startup or shutdown period in the compliance demonstrations. (40 CFR 63.10005(a)(2)(iii)(C))

2) Performance testing requirements: If the owner or operator chooses to use performance testing to demonstrate initial compliance with the applicable emissions limits in Tables 1 and 2 to 40 CFR 63, Subpart UUUUU for the EGUs, the owner or operator shall conduct the tests according to 40 CFR 63.10007 and Table 5 to 40 CFR 63, Subpart UUUUU. For the purposes of the initial compliance demonstration, the owner or operator may use test data and results from a performance test conducted prior to the date on which compliance is required as specified in 40 CFR 63.9984, provided that the following conditions are fully met: (40 CFR 63.10005(b))

(a) For a performance test based on stack test data, the test was conducted no more than 12 calendar months prior to the date on which compliance is required as specified in 40 CFR 63.9984; (40 CFR 63.10005(b)(1))

(b) For a performance test based on data from a certified CEMS or sorbent trap monitoring system, the test consists of all valid CMS data recorded in the 30 boiler operating days immediately preceding that date; (40 CFR 63.10005(b)(2))

(c) The performance test was conducted in accordance with all applicable requirements in 40 CFR 63.10007 and Table 5 to 40 CFR 63, Subpart UUUUU; (40 CFR 63.10005(b)(3))

(d) A record of all parameters needed to convert pollutant concentrations to units of the emission standard (e.g., stack flow rate, diluent gas concentrations, hourly gross outputs) is available for the entire performance test period; and (40 CFR 63.10005(b)(4))

(e) For each performance test based on stack test data, the owner or operator certify, and keep documentation demonstrating, that the EGU configuration, control devices, and fuel(s) have remained consistent with conditions since the prior performance test was conducted. (40 CFR 63.10005(b)(5))

(f) For performance stack test data that are collected prior to the date that compliance must be demonstrated and are used to demonstrate initial compliance with applicable emissions limits, the interval for subsequent stack tests begins on the date that compliance must be demonstrated. (40 CFR 63.10005(b)(6))

3) Operating limits: In accordance with 40 CFR 63.10010 and Table 4 to 40 CFR 63, Subpart UUUUU, the owner or operator may be required to establish operating limits using PM CPMS and using site-specific monitoring for certain liquid oil-fired units as part of the initial compliance demonstration. (40 CFR 63.10005(c))

4) CMS requirements: If, for a particular emission or operating limit, the owner or operator is required to (or elect to) demonstrate initial compliance using a continuous monitoring system, the CMS must pass a performance evaluation prior to the initial compliance demonstration. If a CMS has been previously certified under another state or federal program and is continuing to meet the on-going quality-assurance (QA) requirements of that program, then, provided that the certification and QA provisions of that program meet the applicable requirements of 40 CFR 63.10010(b) through (h), an additional performance evaluation of the CMS is not required under 40 CFR 63, Subpart UUUUU. (40 CFR 63.10005(d))

(a) For an affected coal-fired, solid oil-derived fuel-fired, or liquid oil-fired EGU, the owner or operator may demonstrate initial compliance with the applicable SO_2, HCl, or HF emissions limit in Table 1 or 2 to 40 CFR 63, Subpart UUUUU through use of an SO_2, HCl, or HF CEMS installed and operated in accordance with part 75 to this chapter or Appendix B to 40 CFR 63, Subpart UUUUU, as applicable. The owner or operator may also demonstrate compliance with a filterable PM emission limit in Table 1 or 2 to 40 CFR 63, Subpart UUUUU through use of a PM CEMS installed, certified, and operated in accordance with 40 CFR 63.10010(i). Initial compliance is achieved if the arithmetic average of 30–boiler operating days of quality-assured CEMS data, expressed in units of the standard (see 40 CFR63.10007(e)), meets the applicable $SO_{2,}$ PM, HCl, or HF emissions limit in Table 1 or 2 to 40 CFR 63, Subpart UUUUU. Use Equation 19–19 of Method 19 in appendix A–7 to part 60 of this chapter to calculate the 30–boiler operating day average emissions rate. (Note: for this calculation, the term E_{hj} in Equation 19–19 must be in the same units of measure as the applicable HCl or HF emission limit in Table 1 or 2 to 40 CFR 63, Subpart UUUUU). (40 CFR 63.10005(d)(1))

(b) For affected coal-fired or solid oil-derived fuel-fired EGUs that demonstrate compliance with the applicable emission limits for total nonmercury HAP metals, individual non-mercury HAP metals, total HAP metals, individual HAP metals, or filterable PM listed in Table 1 or 2 to 40 CFR 63, Subpart UUUUU using initial performance testing and continuous monitoring with PM CPMS: (40 CFR 63.10005(d)(2))

(i) The owner or operator shall demonstrate initial compliance no later than the applicable date specified in 40 CFR 63.9984(f) for existing EGUs and in paragraph (g) of this section for new EGUs. (40 CFR 63.10005(d)(2)(i))

(ii) The owner or operator shall demonstrate continuous compliance with the PM CPMS site-specific operating limit that corresponding to the results of the performance test demonstrating compliance with the pollutant with which the owner or operator choose to comply. (40 CFR 63.10005(d)(2)(ii))

(iii) The owner or operator shall repeat the performance test annually for the selected pollutant emissions limit and reassess and adjust the site-specific operating limit in accordance with the results of the performance test. (40 CFR 63.10005(d)(2)(iii))

(c) For affected EGUs that are either required to or elect to demonstrate initial compliance with the applicable Hg emission limit in Table 1 or 2 of 40 CFR 63, Subpart UUUUU using Hg CEMS or sorbent trap monitoring systems, initial compliance must be demonstrated no later than the applicable date specified in 40 CFR 63.9984(f) for existing EGUs and in paragraph (g) of this section for new EGUs. Initial compliance is achieved if the arithmetic average of 30– (or 90-) boiler operating days of quality-assured CEMS (or sorbent trap monitoring system) data, expressed in units of the standard (see section 6.2 of appendix A to 40 CFR 63, Subpart UUUUU), meets the applicable Hg emission limit in Table 1 or 2 to 40 CFR 63, Subpart UUUUU. (40 CFR 63.10005(d)(3))

5) Tune-ups. All affected EGUs are subject to the work practice standards in Table 3 of 40 CFR 63, Subpart UUUUU. As part of the initial compliance demonstration, the owner or operator shall conduct a performance tune-up of the EGU according to 40 CFR 63.10021(e). (40 CFR 63.10005(e))

6) For an existing EGU without a neural network, a tune-up, following the procedures in 40 CFR 63.10021(e), must occur within 6 months (180 days) after April 16, 2015. For an existing EGU with a neural network, a tune-up must occur within 18 months (545 days) after April 16, 2016. If a tune-up occurs prior to April 16, 2015, you must keep records showing that the tune-up met all rule requirements. (40 CFR 63.10005(f))

7) Low emitting EGUs (40 CFR 63.10005(h))

The provisions of this paragraph (h) apply to pollutants with emissions limits from new EGUs except Hg and to all pollutants with emissions limits from existing EGUs. The owner or operator may pursue this compliance option unless prohibited pursuant to 40 CFR 63.10000(c)(1)(i).

(a) An EGU may qualify for low emitting EGU (LEE) status for Hg, HCl, HF, filterable PM, total non-Hg HAP metals, or individual non-Hg HAP metals (or total HAP metals or individual HAP metals, for liquid oil-fired EGUs) if the owner or operator collect performance test data that meet the requirements of this paragraph (h), and if those data demonstrate: (40 CFR 63.10005(h)(1))

(i) For all pollutants except Hg, performance test emissions results less than 50 percent of the applicable emissions limits in Table 1 or 2 to 40 CFR 63, Subpart UUUUU for all required testing for 3 consecutive years; or (40 CFR 63.10005(h)(1)(i))

(ii) For Hg emissions from an existing EGU, either: (40 CFR 63.10005(h)(1)(ii)

(A) Average emissions less than 10 percent of the applicable Hg emissions limit in Table 2 to 40 CFR 63, Subpart UUUUU (expressed either in units of lb/TBtu or lb/GWh); or (40 CFR 63.10005(h)(1)(ii)(A))

(B) Potential Hg mass emissions of 29.0 or fewer pounds per year and compliance with the applicable Hg emission limit in Table 2 to 40 CFR 63, Subpart UUUUU (expressed either in units of lb/TBtu or lb/GWh). (40 CFR 63.10005(h)(1)(ii)(B))

(b) For all pollutants except Hg, the owner or operator shall conduct all required performance tests described in 40 CFR 63.10007 to demonstrate that a unit qualifies for LEE status. (40 CFR 63.10005(h)(2))

(i) When conducting emissions testing to demonstrate LEE status, the owner or operator shall increase the minimum sample volume specified in Table 1 or 2 nominally by a factor of two. (40 CFR 63.10005(h)(2)(i))

(ii) Follow the instructions in 40 CFR 63.10007(e) and Table 5 to 40 CFR 63, Subpart UUUUU to convert the test data to the units of the applicable standard. (40 CFR 63.10005(h)(2)(ii))

(c) For Hg, the owner or operator shall conduct a 30- (or 90-) boiler operating day performance test using Method 30B in appendix A-8 to part 60 of this chapter to determine whether a unit qualifies for LEE status. Locate the Method 30B sampling probe tip at a point within the 10 percent of the duct area centered about the duct's centroid at a location that meets Method 1 in appendix A-1 to part 60 of this chapter and conduct at least three nominally equal length test runs over the 30- (or 90-) boiler operating day test period. The owner or operator may use a pair of sorbent traps to sample the stack gas for a period consistent with that given in section 5.2.1 of appendix A to this subpart. Collect Hg emissions data continuously over the entire test period (except when changing sorbent traps or performing required reference method QA procedures). As an alternative to constant rate sampling per Method 30B, you may use proportional sampling per section 8.2.2 of Performance Specification 12

B in appendix B to part 60 of this chapter. (40 CFR 63.10005(h)(3))

(i) Depending on whether the owner or operator intend to assess LEE status for Hg in terms of the lb/TBtu or lb/GWh emission limit in Table 2 to 40 CFR 63, Subpart UUUUU or in terms of the annual Hg mass emissions limit of 29.0 lb/year, the owner or operator will have to collect some or all of the following data during the 30-boiler operating day test period (see paragraph (h)(3)(iii) of this section): (40 CFR 63.10005(h)(3)(i))

(A) Diluent gas (CO_2 or O_2) data, using either Method 3A in appendix A-3 to part 60 of this chapter or a diluent gas monitor that has been certified according to part 75 of this chapter. (40 CFR 63.10005(h)(3)(i)(A))

(B) Stack gas flow rate data, using either Method 2, 2F, or 2G in appendices A-1 and A-2 to part 60 of this chapter, or a flow rate monitor that has been certified according to part 75 of this chapter. (40 CFR 63.10005(h)(3)(i)(B))

(C) Stack gas moisture content data, using either Method 4 in appendix A-1 to part 60 of this chapter, or a moisture monitoring system that has been certified according to part 75 of this chapter. Alternatively, an appropriate fuel-specific default moisture value from 40 CFR 75.11(b) of this chapter may be used in the calculations or the owner or operator may petition the Administrator under 40 CFR 75.66 of this chapter for use of a default moisture value for non-coal-fired units. (40 CFR 63.10005(h)(3)(i)(C))

(D) Hourly gross output data (megawatts), from facility records. (40 CFR 63.10005(h)(3)(i)(D))

(ii) If the owner or operator use CEMS to measure CO_2 (or O_2) concentration, and/or flow rate, and/or moisture, record hourly average values of each parameter throughout the 30-boiler operating day test period. If the owner or operator opt to use EPA reference methods rather than CEMS for any parameter, the owner or operator shall perform at least one representative test run on each operating day of the test period, using the applicable reference method. (40 CFR 63.10005(h)(3)(ii))

(iii) Calculate the average Hg concentration, in $\mu g/m^3$ (dry basis), for the 30- (or 90-) boiler operating day performance test, as the arithmetic average of all Method 30B sorbent trap results. Also calculate, as applicable, the average values of CO_2 or O_2 concentration, stack gas flow rate, stack gas moisture content, and gross output for the test period. Then: (40 CFR 63.10005(h)(3)(iii))

(A) To express the test results in units of lb/TBtu, follow the procedures in 40 CFR 63.10007(e). Use the average Hg concentration and diluent gas values in the calculations. (40 CFR 63.10005(h)(3)(iii)(A))

(B) To express the test results in units of lb/GWh, use Equations A-3 and A-4 in section 6.2.2 of appendix A to 40 CFR 63, Subpart UUUUU, replacing the hourly values "C_h", "Q_h", "B_{ws}" and "$(MW)_h$" with the average values of these parameters from the performance test. (40 CFR 63.10005(h)(3)(iii)(B))

(C) To calculate pounds of Hg per year, use one of the following methods: (40 CFR 63.10005(h)(3)(iii)(C))

- Multiply the average lb/TBtu Hg emission rate (determined according to paragraph (h)(3)(iii)(A) of this section) by the maximum potential annual heat input to the unit (TBtu), which is equal to the maximum rated unit heat input (TBtu/hr) times 8,760 hours. If the maximum rated heat input value is expressed in units of MMBtu/hr, multiply it by 10^{-6} to convert it to TBtu/hr; or (40 CFR 63.10005(h)(3)(iii)(C)(1))

- Multiply the average lb/GWh Hg emission rate (determined according to paragraph (h)(3)(iii)(B) of this section) by the maximum potential annual electricity generation (GWh), which is equal to the maximum rated electrical output of the unit (GW) times 8,760 hours. If the maximum rated electrical output value is expressed in units of MW, multiply it by 10^{-3} to convert it to GW; or (40 CFR 63.10005(h)(3)(iii)(C)(2))
- If an EGU has a federally-enforceable permit limit on either the annual heat input or the number of annual operating hours, the owner or operator may modify the calculations in paragraph (h)(3)(iii)(C)(1) of this section by replacing the maximum potential annual heat input or 8,760 unit operating hours with the permit limit on annual heat input or operating hours (as applicable). (40 CFR 63.10005(h)(3)(iii)(C)(3))

(d) For a group of affected units that vent to a common stack, the owner or operator may either assess LEE status for the units individually by performing a separate emission test of each unit in the duct leading from the unit to the common stack, or the owner or operator may perform a single emission test in the common stack. If the owner or operator choose the common stack testing option, the units in the configuration qualify for LEE status if: (40 CFR 63.10005(h)(4))

(i) The emission rate measured at the common stack is less than 50 percent (10 percent for Hg) of the applicable emission limit in Table 1 or 2 to 40 CFR 63, Subpart UUUUU; or (40 CFR 63.10005(h)(4)(i))

(ii) For Hg from an existing EGU, the applicable Hg emission limit in Table 2 to 40 CFR 63, Subpart UUUUU is met and the potential annual mass emissions, calculated according to paragraph (h)(3)(iii) of this section (with some modifications), are less than or equal to 29.0 pounds times the number of units sharing the common stack. Base your calculations on the combined heat input capacity of all units sharing the stack (i.e., either the combined maximum rated value or, if applicable, a lower combined value restricted by permit conditions or operating hours). (40 CFR 63.10005(h)(4)(ii))

(e) For an affected unit with a multiple stack or duct configuration in which the exhaust stacks or ducts are downstream of all emission control devices, the owner or operator shall perform a separate emission test in each stack or duct. The unit qualifies for LEE status if: (40 CFR 63.10005(h)(5))

(i) The emission rate, based on all test runs performed at all of the stacks or ducts, is less than 50 percent (10 percent for Hg) of the applicable emission limit in Table 1 or 2 to 40 CFR 63, Subpart UUUUU; or (40 CFR 63.10005(h)(5)(i))

(ii) For Hg from an existing EGU, the applicable Hg emission limit in Table 2 to 40 CFR 63, Subpart UUUUU is met and the potential annual mass emissions, calculated according to paragraph (h)(3)(iii) of this section, are less than or equal to 29.0 pounds. Use the average Hg emission rate from paragraph (h)(5)(i) of this section in your calculations. (40 CFR 63.10005(h)(5)(ii))

8) Startup and shutdown for coal-fired or solid oil derived-fired units: The owner or operator shall follow the requirements given in Table 3 to 40 CFR 63, Subpart UUUUU. (40 CFR 63.10005(j))

9) The owner or operator shall submit a Notification of Compliance Status summarizing the results of the initial compliance demonstration, as provided in 40 CFR63.10030. (40 CFR 63.10005(k))

ii. Date to conduct subsequent performance tests or tune-ups: (40 CFR 63.10006)

1) For liquid oil-fired, solid oil-derived fuel-fired and coal-fired EGUs and IGCC units using PM CPMS to monitor continuous performance with an applicable emission limit as provided for under 40 CFR 63.10000(c), the owner or operator shall conduct all applicable performance tests according to Table 5 to 40 CFR 63, Subpart UUUUU and 40 CFR 63.10007 at least every year. (40 CFR 63.10006(a))

Table 5 to Subpart UUUUU of Part 63 - Performance Testing Requirements [As stated in 40 CFR63.10007. The owner or operator shall comply with the following requirements for performance testing for existing, new or reconstructed affected sources 1] (Modified to include applicable requirements, see Subpart UUUUU for other options)

To conduct a performance test for the following pollutant . . .	**Using ...**	**The owner or operator shall perform the following activities, as applicable to the input- or output-based emission limit . . .**	**Using ...**
1. Filterable Particulate matter (PM) …	Emissions Testing	a. Select sampling ports location and the number of traverse points	Method 1 at Appendix A-1 to part 60 of this chapter.
		b. Determine velocity and volumetric flow-rate of the stack gas	Method 2, 2A, 2C, 2F, 2G or 2H at Appendix A-1 or A-2 to part 60 of this chapter.
		c. Determine oxygen and carbon dioxide concentrations of the stack gas	Method 3A or 3B at Appendix A-2 to part 60 of this chapter, or ANSI/ASME PTC 19.10-1981. [3]
		d. Measure the moisture content of the stack gas	Method 4 at Appendix A-3 to part 60 of this chapter.
		e. Measure the filterable PM concentration	Method 5 at Appendix A-3 to part 60 of this chapter.
			For positive pressure fabric filters, Method 5D at Appendix A-3 to part 60 of this chapter for filterable PM emissions.
			Note that the Method 5 front half temperature shall be 160 ° ± 14 ° C (320 ° ± 25 ° F).
		f. Convert emissions concentration to lb/MMBtu or lb/MWh emissions rates	Method 19 F-factor methodology at Appendix A-7 to part 60 of this chapter, or calculate using mass emissions rate and electrical output data (see 40 CFR 63.10007(e)).
	OR PM CEMS	a. Install, certify, operate, and maintain the PM CEMS	Performance Specification 11 at Appendix B to part 60 of this chapter and Procedure 2 at Appendix F to Part 60 of this chapter.
		b. Install, certify, operate, and maintain the diluent gas, flow rate, and/or moisture monitoring systems	Part 75 of this chapter and 40 CFR40 CFR 63.10010(a), (b), (c), and (d).
		c. Convert hourly emissions concentrations to 30 boiler operating day rolling average lb/MMBtu or lb/MWh emissions rates	Method 19 F-factor methodology at Appendix A-7 to part 60 of this chapter, or calculate using mass emissions rate and electrical output data (see 40 CFR 63.10007(e)).

To conduct a performance test for the following pollutant . . .	**Using ...**	**The owner or operator shall perform the following activities, as applicable to the input- or output-based emission limit . . .**	**Using ...**
2. Total or individual non-Hg HAP metals	Emissions Testing	a. Select sampling ports location and the number of traverse points	Method 1 at Appendix A-1 to part 60 of this chapter.
		b. Determine velocity and volumetric flow-rate of the stack gas	Method 2, 2A, 2C, 2F, 2G or 2H at Appendix A-1 or A-2 to part 60 of this chapter.
		c. Determine oxygen and carbon dioxide concentrations of the stack gas	Method 3A or 3B at Appendix A-2 to part 60 of this chapter, or ANSI/ASME PTC 19.10-1981.[3]
		d. Measure the moisture content of the stack gas	Method 4 at Appendix A-3 to part 60 of this chapter.
		e. Measure the HAP metals emissions concentrations and determine each individual HAP metals emissions concentration, as well as the total filterable HAP metals emissions concentration and total HAP metals emissions concentration	Method 29 at Appendix A-8 to part 60 of this chapter. For liquid oil-fired units, Hg is included in HAP metals and the owner or operator may use Method 29, Method 30B at Appendix A-8 to part 60 of this chapter; for Method 29, the owner or operator shall report the front half and back half results separately. When using Method 29, report metals matrix spike and recovery levels.
		f. Convert emissions concentrations (individual HAP metals, total filterable HAP metals, and total HAP metals) to lb/MMBtu or lb/MWh emissions rates	Method 19 F-factor methodology at Appendix A-7 to part 60 of this chapter, or calculate using mass emissions rate and electrical output data (see 40 CFR 63.10007(e)).
3. Hydrogen chloride (HCl) and hydrogen fluoride (HF)	Emissions Testing	a. Select sampling ports location and the number of traverse points	Method 1 at Appendix A-1 to part 60 of this chapter.
		b. Determine velocity and volumetric flow-rate of the stack gas	Method 2, 2A, 2C, 2F, 2G or 2H at Appendix A-1 or A-2 to part 60 of this chapter.
		c. Determine oxygen and carbon dioxide concentrations of the stack gas	Method 3A or 3B at Appendix A-2 to part 60 of this chapter, or ANSI/ASME PTC 19.10-1981.[3]
		d. Measure the moisture content of the stack gas	Method 4 at Appendix A-3 to part 60 of this chapter.

To conduct a performance test for the following pollutant . . .	Using ...	The owner or operator shall perform the following activities, as applicable to the input- or output-based emission limit . . .	Using ...
		e. Measure the HCl and HF emissions concentrations	Method 26 or Method 26A at Appendix A-8 to part 60 of this chapter or Method 320 at Appendix A to part 63 of this chapter or ASTM 6348-03 [3] with (1) additional quality assurance measures in footnote [4] and (2) spiking levels nominally no greater than two times the level corresponding to the applicable emission limit. Method 26A must be used if there are entrained water droplets in the exhaust stream.
		f. Convert emissions concentration to lb/MMBtu or lb/MWh emissions rates	Method 19 F-factor methodology at Appendix A-7 to part 60 of this chapter, or calculate using mass emissions rate and electrical output data (see 40 CFR 63.10007(e)).
	OR HCl and/or HF CEMS	a. Install, certify, operate, and maintain the HCl or HF CEMS	Appendix B of 40 CFR 63, Subpart UUUUU.
		b. Install, certify, operate, and maintain the diluent gas, flow rate, and/or moisture monitoring systems	Part 75 of this chapter and 40 CFR40 CFR 63.10010(a), (b), (c), and (d).
		c. Convert hourly emissions concentrations to 30 boiler operating day rolling average lb/MMBtu or lb/MWh emissions rates	Method 19 F-factor methodology at Appendix A-7 to part 60 of this chapter, or calculate using mass emissions rate and electrical output data (see 40 CFR 63.10007(e)).
4. Mercury (Hg) …	Emissions Testing …	a. Select sampling ports location and the number of traverse points	Method 1 at Appendix A-1 to part 60 of this chapter or Method 30B at Appendix A-8 for Method 30B point selection.
		b. Determine velocity and volumetric flow-rate of the stack gas	Method 2, 2A, 2C, 2F, 2G or 2H at Appendix A-1 or A-2 to part 60 of this chapter.
		c. Determine oxygen and carbon dioxide concentrations of the stack gas	Method 3A or 3B at Appendix A-1 to part 60 of this chapter, or ANSI/ASME PTC 19.10-1981. [3]
		d. Measure the moisture content of the stack gas	Method 4 at Appendix A-3 to part 60 of this chapter.

To conduct a performance test for the following pollutant . . .	Using ...	The owner or operator shall perform the following activities, as applicable to the input- or output-based emission limit . . .	Using ...
		e. Measure the Hg emission concentration	Method 30B at Appendix A-8 to part 60 of this chapter, ASTM D6784 [3], or Method 29 at Appendix A-8 to part 60 of this chapter; for Method 29, the owner or operator shall report the front half and back half results separately.
		f. Convert emissions concentration to lb/TBtu or lb/GWh emission rates	Method 19 F-factor methodology at Appendix A-7 to part 60 of this chapter, or calculate using mass emissions rate and electrical output data (see 40 CFR 63.10007(e)).
	OR Hg CEMs	a. Install, certify, operate, and maintain the CEMS	Sections 3.2.1 and 5.1 of Appendix A of 40 CFR 63, Subpart UUUUU.
		b. Install, certify, operate, and maintain the diluent gas, flow rate, and/or moisture monitoring systems	Part 75 of this chapter and 40 CFR40 CFR 63.10010(a), (b), (c), and (d).
		c. Convert hourly emissions concentrations to 30 boiler operating day rolling average lb/TBtu or lb/GWh emissions rates	Section 6 of Appendix A to 40 CFR 63, Subpart UUUUU.
	OR Sorbent trap monitoring systems...	a. Install, certify, operate, and maintain the sorbent trap monitoring system	Sections 3.2.2 and 5.2 of Appendix A to 40 CFR 63, Subpart UUUUU.
		b. Install, operate, and maintain the diluent gas, flow rate, and/or moisture monitoring systems	Part 75 of this chapter and 40 CFR40 CFR 63.10010(a), (b), (c), and (d).
		c. Convert emissions concentrations to 30 boiler operating day rolling average lb/TBtu or lb/GWh emissions rates	Section 6 of Appendix A to 40 CFR 63, Subpart UUUUU.
	OR LEE testing	a. Select sampling ports location and the number of traverse points	Single point located at the 10% centroidal area of the duct at a port location per Method 1 at Appendix A-1 to part 60 of this chapter or Method 30B at Appendix A-8 for Method 30B point selection.
		b. Determine velocity and volumetric flow-rate of the stack gas	Method 2, 2A, 2C, 2F, 2G, or 2H at Appendix A-1 or A-2 to part 60 of this chapter or flow monitoring system certified per Appendix A of 40 CFR 63, Subpart UUUUU.

To conduct a performance test for the following pollutant . . .	Using ...	The owner or operator shall perform the following activities, as applicable to the input- or output-based emission limit . . .	Using ...
		c. Determine oxygen and carbon dioxide concentrations of the stack gas	Method 3A or 3B at Appendix A-1 to part 60 of this chapter, or ANSI/ASME PTC 19.10-1981,[3] or diluent gas monitoring systems certified according to Part 75 of this chapter.
		d. Measure the moisture content of the stack gas	Method 4 at Appendix A-3 to part 60 of this chapter, or moisture monitoring systems certified according to part 75 of this chapter.
		e. Measure the Hg emission concentration	Method 30B at Appendix A-8 to part 60 of this chapter; perform a 30 operating day test, with a maximum of 10 operating days per run (*i.e.*, per pair of sorbent traps) or sorbent trap monitoring system or Hg CEMS certified per Appendix A of 40 CFR 63, Subpart UUUUU.
		f. Convert emissions concentrations from the LEE test to lb/TBtu or lb/GWh emissions rates	Method 19 F-factor methodology at Appendix A-7 to part 60 of this chapter, or calculate using mass emissions rate and electrical output data (see 40 CFR 63.10007(e)).
		g. Convert average lb/TBtu or lb/GWh Hg emission rate to lb/year, if the owner or operator are attempting to meet the 22.0 lb/year threshold	Potential maximum annual heat input in TBtu or potential maximum electricity generated in GWh.
5. Sulfur dioxide (SO2) …	SO_2 CEMS …	a. Install, certify, operate, and maintain the CEMS	Part 75 of this chapter and 40 CFR40 CFR 63.10010(a) and (f).
		b. Install, operate, and maintain the diluent gas, flow rate, and/or moisture monitoring systems	Part 75 of this chapter and 40 CFR40 CFR 63.10010(a), (b), (c), and (d).
		c. Convert hourly emissions concentrations to 30 boiler operating day rolling average lb/MMBtu or lb/MWh emissions rates	Method 19 F-factor methodology at Appendix A-7 to part 60 of this chapter, or calculate using mass emissions rate and electrical output data (see 40 CFR 63.10007(e)).

2) For affected units meeting the LEE requirements of 40 CFR 63.10005(h), the owner or operator shall repeat the performance test once every 3 years (once every year for Hg) according to Table 5 and 40 CFR 63.10007. Should subsequent emissions testing results show the unit does not meet the LEE eligibility requirements, LEE status is lost. If this should occur: (40 CFR 63.10006(b))

(a) For all pollutant emission limits except for Hg, the owner or operator shall conduct emissions testing quarterly, except as otherwise provided in 40 CFR 63.10021(d)(1). (40 CFR 63.10006(b)(1))

(b) For Hg, the owner or operator shall install, certify, maintain, and operate a Hg CEMS or a sorbent trap monitoring system in accordance with appendix A to 40 CFR 63, Subpart UUUUU, within 6 calendar months of losing LEE eligibility. Until the Hg CEMS or sorbent trap monitoring system is installed, certified, and operating, the owner or operator shall conduct Hg emissions testing quarterly, except as otherwise provided in 40 CFR 63.10021(d)(1). The owner or operator shall have 3 calendar years of testing and CEMS or sorbent trap monitoring system data that satisfy the LEE emissions criteria to reestablish LEE status. (40 CFR 63.10006(b)(2))

3) Except where paragraphs (a) or (b) of this section apply, or where the owner or operator install, certify, and operate a PM CEMS to demonstrate compliance with a filterable PM emissions limit, for liquid oil-, solid oil-derived fuel-, coal-fired and IGCC EGUs, the owner or operator shall conduct all applicable periodic emissions tests for filterable PM, individual, or total HAP metals emissions according to Table 5 to 40 CFR 63, Subpart UUUUU, 40 CFR 63.10007, and 40 CFR 63.10000(c), except as otherwise provided in 40 CFR 63.10021(d)(1). (40 CFR 63.10006(c))

4) Except where paragraph (b) of this section applies, for solid oil-derived fuel- and coal-fired EGUs that do not use either an HCl CEMS to monitor compliance with the HCl limit or an SO_2 CEMS to monitor compliance with the alternate equivalent SO_2 emission limit, the owner or operator shall conduct all applicable periodic HCl emissions tests according to Table 5 to 40 CFR 63, Subpart UUUUU and 40 CFR 63.10007 at least quarterly, except as otherwise provided in 40 CFR 63.10021(d)(1). (40 CFR 63.10006(d))

5) Time between performance tests. (40 CFR 63.10006(f))

(a) Notwithstanding the provisions of § 63.10021(d)(1), the requirements listed in paragraphs (g) and (h) of this section, and the requirements of paragraph (f)(3) of this section, you must complete performance tests for your EGU as follows: (40 CFR 63.10006(f)(1))

(i) At least 45 calendar days, measured from the test's end date, must separate performance tests conducted every quarter; (40 CFR 63.10006(f)(1)(i))

(ii) For annual testing: (40 CFR 63.10006(f)(1)(ii))

(A) At least 320 calendar days, measured from the test's end date, must separate performance tests; (40 CFR 63.10006(f)(1)(ii)(A))

(B) At least 320 calendar days, measured from the test's end date, must separate annual sorbent trap mercury testing for 30-boiler operating day LEE tests; (40 CFR 63.10006(f)(1)(ii)(B))

(C) At least 230 calendar days, measured from the test's end date, must separate annual sorbent trap mercury testing for 90-boiler operating day LEE tests; and (40 CFR 63.10006(f)(1)(ii)(C))

(iii) At least 1,050 calendar days, measured from the test's end date, must separate performance tests conducted every 3 years. (40 CFR 63.10006(f)(1)(iii))

(b) For units demonstrating compliance through quarterly emission testing, you must conduct a performance test in the 4th quarter of a calendar year if your EGU has skipped performance tests in the first 3 quarters of the calendar year. (40 CFR 63.10006(f)(2))

(c) If your EGU misses a performance test deadline due to being inoperative and if 168 or more boiler operating hours occur in the next test period, you must complete an additional performance test in that period as follows: (40 CFR 63.10006(f)(3))

(i) At least 15 calendar days must separate two performance tests conducted in the same quarter. (40 CFR 63.10006(f)(3)(i))

(ii) At least 107 calendar days must separate two performance tests conducted in the same calendar year. (40 CFR 63.10006(f)(3)(ii))

(iii) At least 350 calendar days must separate two performance tests conducted in the same 3 year period. (40 CFR 63.10006(f)(3)(iii))

6) If the owner or operator elects to demonstrate compliance using emissions averaging under 40 CFR 63.10009, the owner or operator shall continue to conduct performance stack tests at the appropriate frequency given in section (c) through (f) of this section. (40 CFR 63.10006(g))

7) If a performance test on a non-mercury LEE shows emissions in excess of 50 percent of the emission limit and if the owner or operator choose to reapply for LEE status, the owner or operator shall conduct performance tests at the appropriate frequency given in section (c) through (e) of this section for that pollutant until all performance tests over a consecutive 3-year period show compliance with the LEE criteria. (40 CFR 63.10006(h))

8) If the owner or operator is required to meet an applicable tune-up work practice standard, the owner or operator shall conduct a performance tune-up according to 40 CFR 63.10021 (e). (40 CFR 63.10006(i))

(a) For EGUs not employing neural network combustion optimization during normal operation, each performance tune-up specified in 40 CFR 63.10021(e) must be no more than 36 calendar months after the previous performance tune-up. (40 CFR 63.10006(i)(1))

(b) For EGUs employing neural network combustion optimization systems during normal operation, each performance tune-up specified in 40 CFR 63.10021(e) must be no more than 48 calendar months after the previous performance tune-up. (40 CFR 63.10006(i)(2))

9) The owner or operator shall report the results of performance tests and performance tune-ups within 60 days after the completion of the performance tests and performance tune-ups. The reports for all subsequent performance tests must include all applicable information required in 40 CFR 63.10031. (40 CFR 63.10006(j))

iii. Methods and other procedures used for the performance tests: (40 CFR 63.10007)

1) Except as otherwise provided in this section, the owner or operator shall conduct all required performance tests according to 40 CFR 63.7(d), (e), (f), and (h). The owner or operator shall also develop a site-specific test plan according to the requirements in 40 CFR 63.7(c). (40 CFR 63.10007(a))

(a) If the owner or operator uses CEMS (Hg, HCl, SO_2, or other) to determine compliance with a 30–boiler operating day rolling average emission limit, the owner or operator shall collect data for all nonexempt unit operating conditions (see 40 CFR 63.10011(g) and Table 3 to 40 CFR 63, Subpart UUUUU). (40 CFR 63.10007(a)(1))

(b) If the owner or operator conducts performance testing with test methods in lieu of continuous monitoring, operate the unit at maximum normal operating load conditions during each periodic (e.g., quarterly) performance test. Maximum normal operating load will be generally between 90 and 110 percent of design capacity but should be representative of site specific normal operations during each test run. (40 CFR 63.10007(a)(2))

(c) For establishing operating limits with particulate matter continuous parametric monitoring system (PM CPMS) to demonstrate compliance with a PM or non Hg metals emissions limit, operate the unit at maximum normal operating load conditions during the performance test period. Maximum normal operating load will be generally between 90 and 110 percent of design capacity but should be representative of site specific normal operations during each test run. (40 CFR 63.10007(a)(3))

2) The owner or operator shall conduct each performance test (including traditional 3–run stack tests, 30–boiler operating day tests based on CEMS data (or sorbent trap monitoring system data), and 30–boiler operating day Hg emission tests for LEE qualification) according to the requirements in Table 5 to 40 CFR 63, Subpart UUUUU. (40 CFR 63.10007(b))

3) If the owner or operator chooses to comply with the filterable PM emission limit and demonstrate continuous performance using a PM CPMS for an applicable emission limit as provided for in 40 CFR 63.10000(c), The owner or operator shall also establish an operating limit according to 40 CFR 63.10011(b), 63.10023, and Tables 4 and 6 to 40 CFR 63, Subpart UUUUU. Should the owner or operator desire to have operating limits that correspond to loads other than

maximum normal operating load, the owner or operator shall conduct testing at those other loads to determine the additional operating limits. (40 CFR 63.10007(c))

4) Except for a 30–boiler operating day performance test based on CEMS (or sorbent trap monitoring system) data, where the concept of test runs does not apply, the owner or operator shall conduct a minimum of three separate test runs for each performance test, as specified in 40 CFR 63.7(e)(3). Each test run must comply with the minimum applicable sampling time or volume specified in Table 1 or 2 to 40 CFR 63, Subpart UUUUU. Sections 63.10005(d) and (h), respectively, provide special instructions for conducting performance tests based on CEMS or sorbent trap monitoring systems, and for conducting emission tests for LEE qualification. (40 CFR 63.10007(d))

5) To use the results of performance testing to determine compliance with the applicable emission limits in Table 1 or 2 to 40 CFR 63, Subpart UUUUU, proceed as follows: (40 CFR 63.10007(e))

(a) Except for a 30–boiler operating day performance test based on CEMS (or sorbent trap monitoring system) data, if measurement results for any pollutant are reported as below the method detection level (e.g., laboratory analytical results for one or more sample components are below the method defined analytical detection level), the owner or operator shall use the method detection level as the measured emissions level for that pollutant in calculating compliance. The measured result for a multiple component analysis (e.g., analytical values for multiple Method 29 fractions both for individual HAP metals and for total HAP metals) may include a combination of method detection level data and analytical data reported above the method detection level. (40 CFR 63.10007(e)(1))

(b) If the limits are expressed in lb/MMBtu or lb/TBtu, the owner or operator shall use the F-factor methodology and equations in sections 12.2 and 12.3 of EPA Method 19 in appendix A–7 to part 60 of this chapter. In cases where an appropriate F-factor is not listed in Table 19–2 of Method 19, the owner or operator may use F-factors from Table 1 in section 3.3.5 of appendix F to part 75 of this chapter, or F-factors derived using the procedures in section 3.3.6 of appendix to part 75 of this chapter. Use the following factors to convert the pollutant concentrations measured during the initial performance tests to units of lb/scf, for use in the applicable Method 19 equations: (40 CFR 63.10007(e)(2))

(i) Multiply SO_2 ppm by $1.66x10^{-7}$;
(ii) Multiply HCl ppm by $9.43x10^{-8}$;
(iii) Multiply HF ppm by $5.18x10^{-8}$;
(iv) Multiply HAP metals concentrations (mg/dscm) by $6.24x10^{-8}$; and
(v) Multiply Hg concentrations (μg/scm) by $6.24x10^{-11}$.

(c) To determine compliance with emission limits expressed in lb/MWh or lb/GWh, the owner or operator shall first calculate the pollutant mass emission rate during the performance test, in units of lb/h. For Hg, if a CEMS or sorbent trap monitoring system is used, use Equation A–2 or A–3 in appendix A to 40 CFR 63, Subpart UUUUU (as applicable). In all other cases, use an equation that has the general form of Equation A–2 or A–3, replacing the value of K with 1.66×10^{-7}lb/scf-ppm for SO_2 , 9.43×10^{-8}lb/scf-ppm for HCl (if an HCl CEMS is used), 5.18×10^{-8}lb/scf-ppm for HF (if an HF CEMS is used), or 6.24×10^{-8}lb-scm/mg-scf for HAP metals and for HCl and HF (when performance stack testing is used), and defining C_h as the average SO_2 , HCl, or HF concentration in ppm, or the average HAP metals concentration in mg/dscm. This calculation requires stack gas volumetric flow rate (scfh) and (in some cases) moisture content data (see 40 CFR 63.10005(h)(3) and 63.10010). Then, if the applicable emission limit is in units of lb/GWh, use Equation A–4 in appendix A to 40 CFR 63, Subpart UUUUU to calculate the pollutant emission rate in lb/GWh. In this calculation, define $(M)_h$ as the calculated pollutant mass emission rate for the performance test (lb/h), and define $(MW)_h$ as the average gross output during the performance test (megawatts). If the applicable emission limit is in lb/MWh rather than lb/GWh, omit the 10^3 term from Equation A–4 to determine the pollutant emission rate in lb/MWh. (40 CFR 63.10007(e)(3))

6) If the owner or operator elect to (or are required to) use CEMS to continuously monitor Hg, HCl, HF, SO2, or PM emissions (or, if applicable, sorbent trap monitoring systems to continuously collect Hg emissions data), the following default values are available for use in the emission rate calculations during startup periods or shutdown periods (as defined in § 63.10042). For the purposes of this subpart, these default values are not considered to be substitute data.(40 CFR 63.10007(f))

(a) **Diluent cap values**. If you use CEMS (or, if applicable, sorbent trap monitoring systems) to comply with a heat input-based emission rate limit, you may use the following diluent cap values for a startup or shutdown hour in which the measured CO_2 concentration is below the cap value or the measured O_2 concentration is above the cap value: (40 CFR 63.10007(f)(1))

(i) For an IGCC EGU, you may use 1% for CO_2 or 19% for O_2. (40 CFR 63.10007(f)(1)(i))

(ii) For all other EGUs, you may use 5% for CO_2 or 14% for O_2. (40 CFR 63.10007(f)(1)(ii))

(b) **Default gross output**. If you use CEMS to continuously monitor Hg, HCl, HF, SO2, or PM emissions (or, if applicable, sorbent trap monitoring systems to continuously collect Hg emissions data), the following default value is available for use in the emission rate calculations during startup periods or shutdown periods (as defined in § 63.10042). For the purposes of this subpart, this default value is not considered to be substitute data. For a startup or shutdown hour in which there is heat input to an affected EGU but zero gross output, you must calculate the pollutant emission rate using a value equivalent to 5% of the maximum sustainable gross output, expressed in megawatts, as defined in section 6.5.2.1(a)(1) of appendix A to part 75 of this chapter. This default gross output is either the nameplate capacity of the EGU or the highest gross output observed in at least four representative quarters of EGU operation. For a monitored common stack, the default gross output is used only when all EGUs are operating (*i.e.*, combusting fuel) are in startup or shutdown mode, and have zero electrical generation. Under those conditions, a default gross output equal to 5% of the combined maximum sustainable gross output of the EGUs that are operating but have a total of zero gross output must be used to calculate the hourly gross output-based pollutant emissions rate. (40 CFR 63.10007(f)(2))

iv. Use emissions averaging to comply with 40 CFR 63, Subpart UUUUU. (40 CFR 63.10009)

1) General eligibility (40 CFR 63.10009(a))

(a) The owner or operator may use emissions averaging as described in paragraph (a)(2) of this section as an alternative to meeting the requirements of 40 CFR 63.9991 for filterable PM, SO_2 , HF, HCl, non-Hg HAP metals, or Hg on an EGU-specific basis if: (40 CFR 63.10009(a)(1))

(i) The owner or operator has more than one existing EGU in the same subcategory located at one or more contiguous properties, belonging to a single major industrial grouping, which are under common control of the same person (or persons under common control); and (40 CFR 63.10009(a)(1)(i))

(ii) You use CEMS (or sorbent trap monitoring systems for determining Hg emissions) or quarterly emissions testing for demonstrating compliance. (40 CFR 63.10009(a)(1)(ii))

(b) The owner or operator may demonstrate compliance by emissions averaging among the existing EGUs in the same subcategory, if your averaged Hg emissions for EGUs in the "unit designed for coal ≥ 8,300 Btu/lb" subcategory are equal to or less than 1.0 lb/TBtu or 1.1E-2 lb/GWh or if your averaged emissions of individual, other pollutants from other subcategories of such EGUs are equal to or less than the applicable emissions limit in Table 2, according to the procedures in this section. Note that except for Hg emissions from EGUs in the "unit designed for coal ≥ 8,300 Btu/lb" subcategory, the averaging time for emissions averaging for pollutants is 30 days (rolling daily) using data from CEMS or a combination of data from CEMS and manual performance (LEE) testing. The averaging time for emissions averaging for the alternate Hg limit (equal to or less than 1.0 lb/TBtu or 1.1E-2 lb/GWh) from EGUs in the "unit designed for coal ≥ 8,300 Btu/lb" subcategory is 90-boiler operating days (rolling daily) using data from CEMS, sorbent trap monitoring, or a combination of monitoring data and data from manual performance (LEE) testing. For the purposes of this paragraph, 30- (or 90-day) group boiler operating days is defined as a period during which at least one unit in the emissions averaging group operates on each of the 30 or 90 days. The owner or operator shall calculate the weighted average emissions rate for the group in accordance with the procedures in this paragraph using the data from all units in the group including any that operate fewer than 30 (or 90) days during the preceding 30 (or 90) group boiler days. (40 CFR 63.10009(a)(2))

(i) The owner or operator may choose to have your EGU emissions averaging group meet either the heat input basis (MMBtu or TBtu, as appropriate for the pollutant) or gross output basis (MWh or GWh, as appropriate for the pollutant). (40 CFR 63.10009(a)(2)(i))

(ii) The owner or operator may not mix bases within your EGU emissions averaging group. (40 CFR 63.10009(a)(2)(ii))

(iii) The owner or operator may use emissions averaging for affected units in different subcategories if the units vent to the atmosphere through a common stack (see paragraph (m) of this section). (40 CFR 63.10009(a)(2)(iii))

2) Equations (40 CFR 63.10009(b))

Use the following equations when performing calculations for your EGU emissions averaging group:

(a) Group eligibility equations (40 CFR 63.10009(b)(1))

$$WAER_m = \frac{\left[\sum_{j=1}^{p} Herm_j \times Rmm_j\right] + \sum_{k=1}^{m} Ter_k \times Rmt_k}{\left(\sum_{j=1}^{p} Rmm_j\right) + \sum_{k=1}^{m} Rmt_k} \qquad (Eq. 1a)$$

Where:

$WAER_m$ = Maximum Weighted Average Emission Rate in terms of lb/heat input or lb/gross output,

$Herm_{i,j}$ = hourly emission rate (*e.g.,* lb/MMBtu, lb/MWh) from CEMS or sorbent trap monitoring as determined during the initial compliance determination from EGU j,

Rmm_j = Maximum rated heat input, MMBtu/h, or maximum rated gross output, MWh/h, for EGU j,

p = number of EGUs in emissions averaging group that rely on CEMS,

Ter_k = Emissions rate (lb/MMBTU or lb/MWh) as determined during the initial compliance determination of EGU k,

Rmt_k = Maximum rated heat input, MMBtu/h, or maximum rated gross output, MWh/h, for EGU k, and

m = number of EGUs in emissions averaging group that rely on emissions testing.

$$WAER_m = \frac{\sum \left[\left(\sum_{j=1}^{p} Herm_{i,j}\right) \times Smm_j \times Cfm_{j_j}\right] + \sum_{k=1}^{m} Ter_k \times Smt_k \times Cft_k}{\sum \left[\sum_{j=1}^{p} Smm_j \times Cfm_j\right] + \sum_{k=1}^{m} Smt_k \times Cft_k} \quad (Eq.\ 1b)$$

Where:

Variables with the similar names share the descriptions for Equation 1a of this section,

Smm_j = maximum steam generation, lb_{steam}/h or lb/gross output, for EGU j,

Cfm_j = conversion factor, calculated from the most recent compliance test results, in terms units of heat output or gross output per pound of steam generated (MMBtu/lb_{steam} or MWh/lb_{steam}) from EGU j,

Smt_k = maximum steam generation, lb_{steam}/h or lb/gross output, for EGU k, and

Cfm_k = conversion factor, calculated from the most recent compliance test results, in terms units of heat output or gross output per pound of steam generated (MMBtu/lb_{steam} or MWh/lb_{steam}) from EGU k.

(b) Weighted 30-boiler operating day rolling average emissions rate equations for pollutants other than Hg. Use equation 2a or 2b to calculate the 30 day rolling average emissions daily. (40 CFR 63.10009(b)(2))

$$WAER = \frac{\sum_{i=1}^{p}\left[\sum_{i=1}^{n}(Her_i \times Rm_i)\right]_p + \sum_{i=1}^{m}(Ter_i \times Rt_i)}{\sum_{i=1}^{p}\left[\sum_{i=1}^{n}(Rm_i)\right]_p + \sum_{i=1}^{m} Rt_i} \quad (Eq. 2a)$$

Where:

Her_i = hourly emission rate (e.g., lb/MMBtu, lb/MWh) from unit i's CEMS for the preceding 30-group boiler operating days,

Rm_i = hourly heat input or gross output from unit i for the preceding 30-group boiler operating days,

p = number of EGUs in emissions averaging group that rely on CEMS or sorbent trap monitoring,

n = number of hourly rates collected over 30-group boiler operating days,

Ter_i = Emissions rate from most recent emissions test of unit i in terms of lb/heat input or lb/gross output,

Rt_i = Total heat input or gross output of unit i for the preceding 30-boiler operating days, and

m = number of EGUs in emissions averaging group that rely on emissions testing.

$$WAER = \frac{\sum_{i=1}^{p}\left[\sum_{i=1}^{n}(Her_i \times Sm_i \times Cfm_i)\right]_p + \sum_{i=1}^{m}(Ter_i \times St_i \times Cft_i)}{\sum_{i=1}^{p}\left[\sum_{i=1}^{n}(Sm_i \times Cfm_i)\right]_p + \sum_{i=1}^{m} St_i \times Cft_i} \quad (Eq.2b)$$

Where:
variables with similar names share the descriptions for Equation 2a,
Sm_i = steam generation in units of pounds from unit i that uses CEMS for the preceding 30-group boiler operating days,
Cfm_i = conversion factor, calculated from the most recent compliance test results, in units of heat input per pound of steam generated or gross output per pound of steam generated, from unit i that uses CEMS from the preceding 30 group boiler operating days,
St_i = steam generation in units of pounds from unit i that uses emissions testing, and
Cft_i = conversion factor, calculated from the most recent compliance test results, in units of heat input per pound of steam generated or gross output per pound of steam generated, from unit i that uses emissions testing.

(c) Weighted 90-boiler operating day rolling average emissions rate equations for Hg emissions from EGUs in the “coal-fired unit not low rank virgin coal” subcategory. Use equation 3a or 3b to calculate the 90-day rolling average emissions daily. (40 CFR 63.10009(b)(3))

$$WAER = \frac{\sum_{i=1}^{p}\left[\sum_{i=1}^{n}(Her_i \times Rm_i)\right]_p + \sum_{i=1}^{m}(Ter_i \times Rt_i)}{\sum_{i=1}^{p}\left[\sum_{i=1}^{n}(Rm_i)\right]_p + \sum_{i=1}^{m} Rt_i} \quad (Eq.3a)$$

Where:
Her_i = hourly emission rate from unit i's CEMS or Hg sorbent trap monitoring system for the preceding 90-group boiler operating days,
Rm_i = hourly heat input or gross output from unit i for the preceding 90-group boiler operating days,
p = number of EGUs in emissions averaging group that rely on CEMS,
n = number of hourly rates collected over the 90-group boiler operating days,
Ter_i = Emissions rate from most recent emissions test of unit i in terms of lb/heat input or lb/gross output,
Rt_i = Total heat input or gross output of unit i for the preceding 90-boiler operating days, and
m = number of EGUs in emissions averaging group that rely on emissions testing.

$$WAER = \frac{\sum_{i=1}^{p}\left[\sum_{i=1}^{n}(Her_i \times Sm_i \times Cfm_i)\right]_p + \sum_{i=1}^{m}(Ter_i \times St_i \times Cft_i)}{\sum_{i=1}^{p}\left[\sum_{i=1}^{n}(Sm_i \times Cfm_i)\right]_p + \sum_{i=1}^{m} St_i \times Cft_i} \quad (Eq. 3b)$$

Where:
variables with similar names share the descriptions for Equation 2a,
Sm_i = steam generation in units of pounds from unit i that uses CEMS or a Hg sorbent trap monitoring for the preceding 90-group boiler operating days,
Cfm_i = conversion factor, calculated from the most recent compliance test results, in units of heat input per pound of steam generated or gross output per pound of steam generated, from unit i that uses CEMS or sorbent trap monitoring from the preceding 90-group boiler operating days,
St_i = steam generation in units of pounds from unit i that uses emissions testing, and
Cft_i = conversion factor, calculated from the most recent emissions test results, in units of heat input per pound of steam generated or gross output per pound of steam generated, from unit i that uses emissions testing.

3) Separate stack requirements (40 CFR 63.10009(c))

For a group of two or more existing EGUs in the same subcategory that each vent to a separate stack, the owner or operator may average filterable PM, SO_2 , HF, HCl, non-Hg HAP metals, or Hg emissions to demonstrate compliance with the limits in Table 2 to 40 CFR 63, Subpart UUUUU if the owner or operator satisfy the requirements in paragraphs (d) through (j) of this section.

4) For each existing EGU in the averaging group: (40 CFR 63.10009(d))

(a) The emissions rate achieved during the initial performance test for the HAP being averaged must not exceed the emissions level that was being achieved 180 days after April 16, 2015, or the date on which emissions testing done to support your emissions averaging plan is complete (if the Administrator does not require submission and approval of your emissions averaging plan), or the date that the owner or operator begin emissions averaging, whichever is earlier; or (40 CFR 63.10009(d)(1))

(b) The control technology employed during the initial performance test must not be less than the design efficiency of the emissions control technology employed 180 days after

April 16, 2015 or the date that the owner or operator begin emissions averaging, whichever is earlier. (40 CFR 63.10009(d)(2))

5) The weighted-average emissions rate from the existing EGUs participating in the emissions averaging option must be in compliance with the limits in Table 2 to 40 CFR 63, Subpart UUUUU at all times following the date that you begin emissions averaging.. (40 CFR 63.10009(e))

6) Emissions averaging group eligibility demonstration. The owner or operator shall demonstrate the ability for the EGUs included in the emissions averaging group to demonstrate initial compliance according to paragraph (f)(1) or (2) of this section using the maximum rated heat input or gross output over a 30- (or 90-) boiler operating day period of each EGU and the results of the initial performance tests. For this demonstration and prior to preparing your emissions averaging plan, the owner or operator shall conduct required emissions monitoring for 30- (or 90-) days of boiler operation and any required manual performance testing to calculate maximum weighted average emissions rate in accordance with this section. If, before the start of your initial compliance demonstration, the Administrator becomes aware that you intend to use emissions averaging for that demonstration, or if your initial Notification of Compliance Status (NOCS) indicates that you intend to implement emissions averaging at a future date, the Administrator may require you to submit your proposed emissions averaging plan and supporting data for approval. If the Administrator requires approval of your plan, the owner or operator may not begin using emissions averaging until the Administrator approves your plan. (40 CFR 63.10009(f))

(a) The owner or operator shall use Equation 1a in paragraph (b) of this section to demonstrate that the maximum weighted average emissions rates of filterable PM, HF, SO_2 , HCl, non-Hg HAP metals, or Hg emissions from the existing units participating in the emissions averaging option do not exceed the emissions limits in Table 2 to 40 CFR 63, Subpart UUUUU. (40 CFR 63.10009(f)(1))

(b) If the owner or operators are not capable of monitoring heat input or gross output, and the EGU generates steam for purposes other than generating electricity, the owner or operator may use Equation 1b of this section as an alternative to using Equation 1a of this section to demonstrate that the maximum weighted average emissions rates of filterable

PM, HF, SO_2 , HCl, non-Hg HAP metals, or Hg emissions from the existing units participating in the emissions averaging group do not exceed the emission limits in Table 2 to 40 CFR 63, Subpart UUUUU. (40 CFR 63.10009(f)(2))

7) The owner or operator shall determine the weighted average emissions rate in units of the applicable emissions limit on a 30 group boiler operating day rolling average basis (or, if applicable, on a 90 group boiler operating day rolling average basis for Hg) basis according to paragraphs (g)(1) through (2) of this section. The first averaging period ends on the 30th (or, if applicable, 90th for the alternate Hg emission limit) group boiler operating day after the date that you begin emissions averaging.(40 CFR 63.10009(g))

(a) The owner or operator shall use Equation 2a or 3a of paragraph (b) of this section to calculate the weighted average emissions rate using the actual heat input or gross output for each existing unit participating in the emissions averaging option. (40 CFR 63.10009(g)(1))

(b) If the owner or operators are not capable of monitoring heat input or gross output, the owner or operator may use Equation 2b or 3b of paragraph (b) of this section as an alternative to using Equation 2a of paragraph (b) of this section to calculate the average weighted emission rate using the actual steam generation from the units participating in the emissions averaging option. (40 CFR 63.10009(g)(2))

8) 63.10009(h) CEMS (or sorbent trap monitoring) use. (40 CFR 63.10009(h))

If an EGU in your emissions averaging group uses CEMS (or a sorbent trap monitor for Hg emissions) to demonstrate compliance, the owner or operator shall use those data to determine the 30 (or 90) group boiler operating day rolling average emissions rate.

9) Emissions testing (40 CFR 63.10009(i))

If the owner or operator use manual emissions testing to demonstrate compliance for one or more EGUs in your emissions averaging group, the owner or operator shall use the results from the most recent performance test to determine the 30 (or 90) day rolling average. The owner or operator may use CEMS or sorbent trap data in combination with data from the most recent manual performance test in calculating the 30 (or 90) group boiler operating day rolling average emissions rate.

10) Emissions averaging plan. (40 CFR 63.10009(j))

The owner or operator shall develop an implementation plan for emissions averaging according to the following procedures and requirements in paragraphs (j)(1) and (2) of this section.

(a) The owner or operator shall include the information contained in paragraphs (j)(1)(i) through (v) of this section in your implementation plan for all the emissions units included in an emissions averaging: (40 CFR 63.10009(j)(1))

(i) The identification of all existing EGUs in the emissions averaging group, including for each either the applicable HAP emission level or the control technology installed as of 180 days after February 16, 2015, or the date on which the owner or operator complete the emissions measurements used to support your emissions averaging plan (if the Administrator does not require submission and approval of your emissions averaging plan), or the date that the owner or operator begin emissions averaging, whichever is earlier; and the date on which the owner or operator are requesting emissions averaging to commence; (40 CFR 63.10009(j)(1)(i))

(ii) The process weighting parameter (heat input, gross output, or steam generated) that will be monitored for each averaging group; (40 CFR 63.10009(j)(1)(ii))

(iii) The specific control technology or pollution prevention measure to be used for each emission EGU in the averaging group and the date of its installation or application. If the pollution prevention measure reduces or eliminates emissions from multiple EGUs, the owner or operator shall identify each EGU; (40 CFR 63.10009(j)(1)(iii))

(iv) The means of measurement (*e.g.*, CEMS, sorbent trap monitoring, manual performance test) of filterable PM, SO_2 , HF, HCl, individual or total non-Hg HAP metals, or Hg emissions in accordance with the requirements in 40 CFR 63.10007 and to be used in the emissions averaging calculations; and (40 CFR 63.10009(j)(1)(iv))

(v) A demonstration that emissions averaging can produce compliance with each of the applicable emission limit(s) in accordance with paragraph (b)(1) of this section. (40 CFR 63.10009(j)(1)(v))

(b) If, as described in paragraph (f) of this section, the Administrator requests the owner or operator to submit the averaging plan for review and approval, the owner or operator shall receive approval before initiating emissions averaging. (40 CFR 63.10009(j)(2))

(i) The Administrator shall use following criteria in reviewing and approving or disapproving the plan: (40 CFR 63.10009(j)(2)(i))

(A) Whether the content of the plan includes all of the information specified in paragraph (j)(1) of this section; and (40 CFR 63.10009(j)(2)(i)(A))

(B) Whether the plan presents information sufficient to determine that compliance will be achieved and maintained. (40 CFR 63.10009(j)(2)(i)(B))

(ii) The Administrator shall not approve an emissions averaging implementation plan containing any of the following provisions: (40 CFR 63.10009(j)(2)(ii))

(A) Any averaging between emissions of different pollutants or between units located at different facilities; or (40 CFR 63.10009(j)(2)(ii)(A))

(B) The inclusion of any emissions unit other than an existing unit in the same subcategory. (40 CFR 63.10009(j)(2)(ii)(B))

11) Common stack requirements (40 CFR 63.10009(k))

For a group of two or more existing affected units, each of which vents through a single common stack, the owner or operator may average emissions to demonstrate compliance with the limits in Table 2 to 40 CFR 63, Subpart UUUUU if the owner or operator satisfy the requirements in paragraph (l) or (m) of this section.

12) For a group of two or more existing units in the same subcategory and which vent through a common emissions control system to a common stack that does not receive emissions from units in other subcategories or categories, the owner or operator may treat such averaging group as a single existing unit for purposes of 40 CFR 63, Subpart UUUUU and comply with the requirements of 40 CFR 63, Subpart UUUUU as if the group were a single unit. (40 CFR 63.10009(l))

13) For all other groups of units subject to paragraph (k) of this section, the owner or operator may elect to conduct manual performance tests according to procedures specified in 40 CFR 63.10007 in the common stack. If emissions from affected units included in the emissions averaging and from other units not included in the emissions averaging (*e.g.,* in a different subcategory) or other nonaffected units all vent to the common stack, the owner or operator shall shut down the units not included in the emissions averaging and the nonaffected units or vent their emissions to a different stack during the performance test. Alternatively, the owner or operator may conduct a performance test of the combined emissions in the common stack with all units operating and show that the combined emissions meet the most stringent emissions limit. The owner or operator may also use a CEMS or sorbent trap monitoring to apply this latter alternative to demonstrate that the combined emissions comply with the most stringent emissions limit on a continuous basis. (40 CFR 63.10009(m))

14) Combination requirements. The common stack of a group of two or more existing EGUs in the same subcategory subject to paragraph (k) of this section may be treated as a single stack for purposes of paragraph (c) of this section and included in an emissions averaging group subject to paragraph (c) of this section. (40 CFR 63.10009(n))

v. Monitoring, installation, operation, and maintenance requirements: (40 CFR 63.10010)

1) Flue gases from the affected units under 40 CFR 63, Subpart UUUUU exhaust to the atmosphere through a variety of different configurations, including but not limited to individual stacks, a common stack configuration or a main stack plus a bypass stack. For the CEMS, PM CPMS, and sorbent trap monitoring systems used to provide data under 40 CFR 63, Subpart UUUUU, the continuous monitoring system installation requirements for these exhaust configurations are as follows: (40 CFR 63.10010(a))

(a) Single unit-single stack configurations. For an affected unit that exhausts to the atmosphere through a single, dedicated stack, the owner or operator shall either install the required CEMS, PM CPMS, and sorbent trap monitoring systems in the stack or at a location in the ductwork downstream of all emissions control devices, where the pollutant and diluents concentrations are representative of the emissions that exit to the atmosphere. (40 CFR 63.10010(a)(1))

(b) Unit utilizing common stack with other affected unit(s). When an affected unit utilizes a common stack with one or more other affected units, but no non-affected units, the owner or operator shall either: (40 CFR 63.10010(a)(2))

(i) Install the required CEMS, PM CPMS, and sorbent trap monitoring systems in the duct leading to the common stack from each unit; or (40 CFR 63.10010(a)(2)(i))

(ii) Install the required CEMS, PM CPMS, and sorbent trap monitoring systems in the common stack. (40 CFR 63.10010(a)(2)(ii))

(c) Unit(s) utilizing common stack with non-affected unit(s). (40 CFR 63.10010(a)(3))

(i) When one or more affected units shares a common stack with one or more non-affected units, the owner or operator shall either: (40 CFR 63.10010(a)(3)(i))

(A) Install the required CEMS, PM CPMS, and sorbent trap monitoring systems in the ducts leading to the common stack from each affected unit; or (40CFR63.10010(a)(3)(i)(A))

(B) Install the required CEMS, PM CPMS, and sorbent trap monitoring systems described in this section in the common stack and attribute all of the emissions measured at the common stack to the affected unit(s). (40CFR63.10010(a)(3)(i)(B))

(ii) If the owner or operator chooses the common stack monitoring option: (40 CFR 63.10010(a)(3)(ii))

(A) For each hour in which valid data are obtained for all parameters, the owner or operator shall calculate the pollutant emission rate and (40CFR63.10010(a)(3)(ii)(A))

(B) The owner or operator shall assign the calculated pollutant emission rate to each unit that shares the common stack. (40CFR63.10010(a)(3)(ii)(B))

(d) Unit with a main stack and a bypass stack that exhausts to the atmosphere independent of the main stack. If the exhaust configuration of an affected unit consists of a main stack and a bypass stack, the owner or operator shall install CEMS on both the main stack and the bypass stack. If it is not feasible to certify and quality-assure the data from a monitoring system on the bypass stack, the owner or operator shall: (40 CFR 63.10010(a)(4))

(i) Route the exhaust from the bypass through the main stack and its monitoring so that bypass emissions are measured; or (40 CFR 63.10010(a)(4)(i))

(ii) Install a CEMS only on the main stack and count hours that the bypass stack is in use as hours of deviation from the monitoring requirements. (40 CFR 63.10010(a)(4)(ii))

(e) Unit with a common control device with multiple stack or duct configuration. If the flue gases from an affected unit, which is configured such that emissions are controlled with a common control device or series of control devices, are discharged to the atmosphere through more than one stack or are fed into a single stack through two or more ducts, the owner or operator may: (40 CFR 63.10010(a)(5))

(i) Install required CEMS, PM CPMS, and sorbent trap monitoring systems in each of the multiple stacks; (40 CFR 63.10010(a)(5)(i))

(ii) Install required CEMS, PM CPMS, and sorbent trap monitoring systems in each of the ducts that feed into the stack; (40 CFR 63.10010(a)(5)(ii))

(iii) Install required CEMS, PM CPMS, and sorbent trap monitoring systems in one of the multiple stacks or ducts and monitor the flows and dilution rates in all multiple stacks or ducts in order to determine total exhaust gas flow rate and pollutant mass emissions rate in accordance with the applicable limit; or (40 CFR 63.10010(a)(5)(iii))

(iv) In the case of multiple ducts feeding into a single stack, install CEMS, PM CPMS, and sorbent trap monitoring systems in the single stack as described in paragraph (a)(1) of this section. (40 CFR 63.10010(a)(5)(iv))

(f) Unit with multiple parallel control devices with multiple stacks: If the flue gases from an affected unit, which is configured such that emissions are controlled with multiple parallel control devices or multiple series of control devices are discharged to the atmosphere through more than one stack, the owner or operator shall install the required CEMS, PM CPMS, and sorbent trap monitoring systems described in each of the multiple stacks. The owner or operator shall calculate hourly flow-weighted average pollutant emission rates for the unit as follows: (40 CFR 63.10010(a)(6))

(i) Calculate the pollutant emission rate at each stack or duct for each hour in which valid data are obtained for all parameters; (40 CFR 63.10010(a)(6)(i))

(ii) Multiply each calculated hourly pollutant emission rate at each stack or duct by the corresponding hourly stack gas flow rate at that stack or duct; (40 CFR 63.10010(a)(6)(ii))

(iii) Sum the products determined under paragraph (a)(6)(ii) of this section; and (40 CFR 63.10010(a)(6)(iii))

(iv) Divide the result obtained in paragraph (a)(6)(iii) of this section by the total hourly stack gas flow rate for the unit, summed across all of the stacks or ducts. (40 CFR 63.10010(a)(6)(iv))

2) If the owner or operator use an oxygen (O_2) or carbon dioxide (CO_2) CEMS to convert measured pollutant concentrations to the units of the applicable emissions limit, the O_2 or CO_2 concentrations shall be monitored at a location that represents emissions to the atmosphere, *i.e.*, at the outlet of the EGU, downstream of all emission control

devices. The owner or operator shall install, certify, maintain, and operate the CEMS according to part 75 of this chapter. Use only quality-assured O_2 or CO_2 data in the emissions calculations; do not use part 75 substitute data values. (40 CFR 63.10010(b))

3) If the owner or operator is required to use a stack gas flow rate monitor, either for routine operation of a sorbent trap monitoring system or to convert pollutant concentrations to units of an electrical output-based emission standard in Table 1 or 2 to 40 CFR 63, Subpart UUUUU, the owner or operator shall install, certify, operate, and maintain the monitoring system and conduct on-going quality-assurance testing of the system according to part 75 of this chapter. Use only unadjusted, quality-assured flow rate data in the emissions calculations. Do not apply bias adjustment factors to the flow rate data and do not use substitute flow rate data in the calculations. (40 CFR 63.10010(c))

4) If the owner or operator is required to make corrections for stack gas moisture content when converting pollutant concentrations to the units of an emission standard in Table 1 of 2 to 40 CFR 63, Subpart UUUUU, the owner or operator shall install, certify, operate, and maintain a moisture monitoring system in accordance with part 75 of this chapter. Alternatively, for coal-fired units, the owner or operator may use appropriate fuel-specific default moisture values from 40 CFR 75.11(b) of this chapter to estimate the moisture content of the stack gas or the owner or operator may petition the Administrator under 40 CFR 75.66 of this chapter for use of a default moisture value for non-coal-fired units. If the owner or operator install and operate a moisture monitoring system, do not use substitute moisture data in the emissions calculations. (40 CFR 63.10010(d))

5) If the owner or operator use an HCl and/or HF CEMS, the owner or operator shall install, certify, operate, maintain, and quality-assure the data from the monitoring system in accordance with appendix B to 40 CFR 63, Subpart UUUUU. Calculate and record a 30-boiler operating day rolling average HCl or HF emission rate in the units of the standard, updated after each new boiler operating day. Each 30-boiler operating day rolling average emission rate is the average of all the valid hourly HCl or HF emission rates in the preceding 30 boiler operating days (see section 9.4 ofappendix B to 40 CFR 63, Subpart UUUUU). (40 CFR 63.10010(e))

6) If the owner or operator uses an SO_2 CEMS:

(a) If the owner or operator uses an SO_2 CEMS, the owner or operator shall install the monitor at the outlet of the EGU, downstream of all emission control devices, and the owner or operator shall certify, operate, and maintain the CEMS according to part 75 of this chapter. (40 CFR 63.10010(f)(1))

(b) For on-going QA, the SO_2 CEMS must meet the applicable daily, quarterly, and semiannual or annual requirements in sections 2.1 through 2.3 of appendix B to part 75 of this chapter, with the following addition: The owner or operator shall perform the linearity checks required in section 2.2 of appendix B to part 75 of this chapter if the SO_2 CEMS has a span value of 30 ppm or less. (40 CFR 63.10010(f)(2))

(c) Calculate and record a 30–boiler operating day rolling average SO_2 emission rate in the units of the standard, updated after each new boiler operating day. Each 30–boiler operating day rolling average emission rate is the average of all of the valid hourly SO_2 emission rates in the 30 boiler operating day period. (40 CFR 63.10010(f)(3))

(d) Use only unadjusted, quality-assured SO_2 concentration values in the emissions calculations; do not apply bias adjustment factors to the part 75 SO_2 data and do not use part 75 substitute data values. For startup or shutdown hours (as defined in 40 CFR 63.10042) the default gross output and the diluent cap are available for use in the hourly SO2 emission rate calculations, as described in 40 CFR 63.10007(f). Use a flag to identify each startup or shutdown hour and report a special code if the diluent cap or default gross output is used to calculate the SO2 emission rate for any of these hours. (40 CFR 63.10010(f)(4))

7) If the owner or operator use a Hg CEMS or a sorbent trap monitoring system, the owner or operator shall install, certify, operate, maintain and quality-assure the data from the monitoring system in accordance with appendix A to 40 CFR 63, Subpart UUUUU. The owner or operator shall calculate and record a 30- (or, if alternate emissions averaging is used, 90-) boiler operating day rolling average Hg emission rate, in units of the standard, updated after each new boiler operating day. Each 30- (or, if alternate emissions averaging is used, 90-) boiler operating day rolling average emission rate, calculated according to section 6.2 of appendix A to the subpart, is the average of all of the valid hourly Hg emission rates in the preceding 30- (or, if alternate emissions averaging is used, a 90-) boiler operating days. Section 7.1.4.3 of appendix A to 40 CFR

63, Subpart UUUUU explains how to reduce sorbent trap monitoring system data to an hourly basis. (40 CFR 63.10010(g))

8) If the owner or operator uses a PM CPMS to demonstrate continuous compliance with an operating limit, the owner or operator shall install, calibrate, maintain, and operate the PM CPMS and record the output of the system as specified in paragraphs (h)(1) through (5) of this section. (40 CFR 63.10010(h))

(a) Install, calibrate, operate, and maintain the PM CPMS according to the procedures in the approved site-specific monitoring plan developed in accordance with 40 CFR 63.10000(d), and meet the requirements in paragraphs (h)(1)(i) through (iii) of this section. (40 CFR 63.10010(h)(1))

(i) The operating principle of the PM CPMS must be based on in-stack or extractive light scatter, light scintillation, beta attenuation, or mass accumulation detection of the exhaust gas or representative sample. The reportable measurement output from the PM CPMS may be expressed as milliamps, stack concentration, or other raw data signal. (40 CFR 63.10010(h)(1)(i))

(ii) The PM CPMS must have a cycle time (i.e., period required to complete sampling, measurement, and reporting for each measurement) no longer than 60 minutes. (40 CFR 63.10010(h)(1)(ii))

(iii) The PM CPMS must be capable, at a minimum, of detecting and responding to particulate matter concentrations of 0.5 mg/acm. (40 CFR 63.10010(h)(1)(iii))

(b) For a new unit, complete the initial PM CPMS performance evaluation no later than October 13, 2012 or 180 days after the date of initial startup, whichever is later. For an existing unit, complete the initial performance evaluation no later than October 13, 2015. (40 CFR 63.10010(h)(2))

(c) Collect PM CPMS hourly average output data for all boiler operating hours except as indicated in paragraph (h)(5) of this section. Express the PM CPMS output as milliamps, PM concentration, or other raw data signal value. (40 CFR 63.10010(h)(3))

(d) Calculate the arithmetic 30–boiler operating day rolling average of all of the hourly average PM CPMS output collected during all nonexempt boiler operating hours data (*e.g.*, milliamps, PM concentration, raw data signal). (40 CFR 63.10010(h)(4))

(e) The owner or operator shall collect data using the PM CPMS at all times the process unit is operating and at the intervals specified in paragraph (h)(1)(ii) of this section, except for periods of monitoring system malfunctions, repairs associated with monitoring system malfunctions, required monitoring system quality assurance or quality control activities (including, as applicable, calibration checks and required zero and span adjustments), and any scheduled maintenance as defined in the site-specific monitoring plan. (40 CFR 63.10010(h)(5))

(f) The owner or operator shall use all the data collected during all boiler operating hours in assessing the compliance with the operating limit except: (40 CFR 63.10010(h)(6))

(i) Any data collected during monitoring system malfunctions, repairs associated with monitoring system malfunctions, or required monitoring system quality assurance or quality control activities that temporarily interrupt the measurement of output data from the PM CPMS. The owner or operator shall report any monitoring system malfunctions or out of control periods in your annual deviation reports. The owner or operator shall report any monitoring system quality assurance or quality control activities per the requirements of 40 CFR 63.10031(b); (40 CFR 63.10010(h)(6)(i))

(ii) Any data collected during periods when the monitoring system is out of control as specified in the site-specific monitoring plan, repairs associated with periods when the monitoring system is out of control, or required monitoring system quality assurance or quality control activities conducted during out-of-control periods. are not used in calculations (report emissions The owner or operator shall report any such periods in your annual deviation report; (40 CFR 63.10010(h)(6)(ii))

(iii) Any data recorded during periods of startup or shutdown. (40 CFR 63.10010(h)(6)(iii))

(g) The owner or operator shall record and make available upon request results of PM CPMS system performance audits, as well as the dates and duration of periods from when the PM CPMS is out of control until completion of the corrective actions necessary to return the PM CPMS to operation consistent with the site-specific monitoring plan. (40 CFR 63.10010(h)(7))

9) If the owner or operator chooses to comply with the PM filterable emissions limit in lieu of metal HAP limits, the owner or operator may choose to install, certify, operate, and maintain a PM CEMS and record the output of the PM CEMS as specified in paragraphs (i)(1) through (5) of this section. The compliance limit will be expressed as a 30–boiler operating day rolling average of the numerical emissions limit value applicable for the unit in tables 1 or 2 to 40 CFR 63, Subpart UUUUU. (40 CFR 63.10010(i))

(a) Install and certify the PM CEMS according to the procedures and requirements in Performance Specification 11—Specifications and Test Procedures for Particulate Matter Continuous Emission Monitoring Systems at Stationary Sources in Appendix B to part 60 of this chapter, using Method 5 at Appendix A–3 to part 60 of this chapter and ensuring that the front half filter temperature shall be 160° ± 14°C (320° ± 25°F). The reportable measurement output from the PM CEMS must be expressed in units of the applicable emissions limit (*e.g.*, lb/MMBtu, lb/MWh). (40 CFR 63.10010(i)(1))

(b) Operate and maintain the PM CEMS according to the procedures and requirements in Procedure 2—Quality Assurance Requirements for Particulate Matter Continuous Emission Monitoring Systems at Stationary Sources in Appendix F to part 60 of this chapter. (40 CFR 63.10010(i)(2))

(i) The owner or operator shall conduct the relative response audit (RRA) for the PM CEMS at least once annually. (40 CFR 63.10010(i)(2)(i))

(ii) The owner or operator shall conduct the relative correlation audit (RCA) for the PM CEMS at least once every 3 years. (40 CFR 63.10010(i)(2)(ii))

(c) Collect PM CEMS hourly average output data for all boiler operating hours except as indicated in paragraph (i) of this section. (40 CFR 63.10010(i)(3))

(d) Calculate the arithmetic 30–boiler operating day rolling average of all of the hourly average PM CEMS output data collected during all nonexempt boiler operating hours. (40 CFR 63.10010(i)(4))

(e) The owner or operator shall collect data using the PM CEMS at all times the process unit is operating and at the intervals specified in paragraph (a) of this section, except for periods of monitoring system malfunctions, repairs associated with monitoring system malfunctions, and required monitoring system quality assurance or quality control activities. (40 CFR 63.10010(i)(5))

(i) The owner or operator shall use all the data collected during all boiler operating hours in assessing the compliance with the operating limit except: (40 CFR 63.10010(i)(5)(i))

(A) Any data collected during monitoring system malfunctions, repairs associated with monitoring system malfunctions, or required monitoring system quality assurance or quality control activities that temporarily interrupt the measurement of emissions (e.g., calibrations, certain audits). The owner or operator shall report any monitoring system malfunctions or out of control periods in your annual deviation reports. The owner or operator shall report any monitoring system quality assurance or quality control activities per the requirements of 40 CFR 63.10031(b); (40 CFR 63.10010(i)(5)(i)(A))

(B) Any data collected during periods when the monitoring system is out of control as specified in the site-specific monitoring plan, repairs associated with periods when the monitoring system is out of control, or required monitoring system quality assurance or quality control activities conducted during out of control periods. The owner or operator shall report any such periods in your annual deviation report; (40 CFR 63.10010(i)(5)(i)(B))

(C) Any data recorded during periods of startup or shutdown. (40 CFR 63.10010(i)(5)(i)(C))

(ii) The owner or operator shall record and make available upon request results of PM CEMS system performance audits, dates and duration of periods when the PM CEMS is out of control to completion of the corrective actions necessary to return the PM CEMS to operation consistent with the site-specific monitoring plan. (40 CFR 63.10010(i)(5)(ii))

vi. Demonstrate initial compliance with the emissions limits and work practice standards: (40 CFR 63.10011)

1) The owner or operator shall demonstrate initial compliance with each emissions limit that applies to the owner or operator by conducting performance testing. (40 CFR 63.10011(a))

2) If the owner or operator is subject to an operating limit in Table 4 to 40 CFR 63, Subpart UUUUU, the owner or operator demonstrates initial compliance with HAP metals or filterable PM emission limit(s) through performance stack tests and the owner or operator elect to use a PM CPMS to demonstrate continuous performance, or if, for a liquid oil-fired unit, and the owner or operator uses quarterly stack testing for HCl and HF plus site-specific parameter monitoring to demonstrate continuous performance, the owner or operator shall also establish a site-specific operating limit, in accordance with 40 CFR 63.10007, and Table 6 to 40 CFR 63, Subpart UUUUU. The owner or operator may use only the parametric data recorded during successful performance tests (i.e., tests that demonstrate compliance with the applicable emissions limits) to establish an operating limit. (40 CFR 63.10011(b))

Table 6 to Subpart UUUUU of Part 63 - 63—Establishing PM CPMS Operating Limits [As stated in 40 CFR63.10007. The owner or operator shall comply with the following requirements for establishing operating limits]

If the owner or operator has an applicable emission limit for . . .	And the owner or operator choose to establish PM CPMS operating limits,the owner or operator shall...	And . . .	Using . . .	According to the following procedures...
Filterable particulate matter (PM), total non-mercury HAP metals, individual non-mercury HAP metals, total HAP metals, individual HAP metals for an EGU …	Install, certify, maintain, and operate a PM CPMS for monitoring emissions discharged to the atmosphere according to 40 CFR63.10010(h)(1) …	Establish a site-specific operating limit in units of PM CPMS output signal (e.g., milliamps, mg/acm, or other raw signal) …	Data from the PM CPMS and the PM or HAP metals performance tests …	1. Collect PM CPMS output data during the entire period of the performance tests. 2. Record the average hourly PM CPMS output for each test run in the performance test. 3. Determine the PM CPMS operating limit in accordance with the requirements of § 63.10023(b)(2) from data obtained during the performance test demonstrating compliance with the filterable PM or HAP metals emissions limitations.

3) Use CEMS:

(a) If the owner or operator uses CEMS or sorbent trap monitoring systems to measure a HAP (e.g., Hg or HCl) directly, the initial performance test, shall consist of a 30-boiler operating day (or, for certain coal-fired, existing EGUs that use emissions averaging for Hg, a 90-boiler operating day) rolling average emissions rate obtained with a certified CEMS or sorbent trap system, expressed in units of the standard. If the monitoring system is certified prior to the applicable compliance date, the initial averaging period shall either begin with: The first boiler operating day on or after the compliance date; or 30 (or, if applicable, 90) boiler operating days prior to that date, as described in 40 CFR 63.10005(b). In all cases, the initial 30- or 90-boiler operating day averaging period must be completed on or before the date that compliance must be demonstrated, in accordance with § 63.9984(f). Initial compliance is demonstrated if the results of the performance test meet the applicable emission limit in Table 1 or 2 to this subpart. (40 CFR 63.10011(c)(1))

(b) For a unit that uses a CEMS to measure SO_2 or PM emissions for initial compliance, the initial performance test shall consist of a 30-boiler operating day average emission rate obtained with certified CEMS, expressed in units of the standard. If the monitoring system is certified prior to the applicable compliance date, the initial averaging period shall either begin with: The first boiler operating day on or after the compliance date; or 30 boiler operating days prior to that date, as described in § 63.10005(b). In all cases, the initial 30- boiler operating day averaging period must be completed on or before the date that compliance must be demonstrated, in accordance with § 63.9984(f). Initial compliance is demonstrated if the results of the performance test meet the applicable SO2 or PM emission limit in Table 1 or 2 to this subpart. (40 CFR 63.10011(c)(2))

4) For candidate LEE units, use the results of the performance testing described in 40 CFR 63.10005(h) to determine initial compliance with the applicable emission limit(s) in Table 1 or 2 to 40 CFR 63, Subpart UUUUU and to determine whether the unit qualifies for LEE status. (40 CFR 63.10011(d))

5) The owner or operator shall submit a Notification of Compliance Status containing the results of the initial compliance demonstration, in accordance with 40 CFR 63.10030(e). (40 CFR 63.10011(e))

6) Cleanest fuel:

(a) The owner or operator shall determine the fuel whose combustion produces the least uncontrolled emissions, i.e., the cleanest fuel, either natural gas or distillate oil, that is available on site or accessible nearby for use during periods of startup or shutdown. (40 CFR 63.10011(f)(1))

(b) The owner or operator’s cleanest fuel, either natural gas or distillate oil, for use during periods of startup or shutdown determination may take safety considerations into account. (40 CFR 63.10011(f)(2))

7) The owner or operator shall follow the startup or shutdown requirements as established in Table 3 to this subpart for each coal-

fired, liquid oil-fired, and solid oil-derived fuel-fired EGU. (40 CFR 63.10011(g))

(a) The owner or operator may use the diluent cap and default gross output values, as described in § 63.10007(f), during startup periods or shutdown periods. (40 CFR 63.10011(g)(1))

(b) The owner or operator shall operate all CMS, collect data, calculate pollutant emission rates, and record data during startup periods or shutdown periods. (40 CFR 63.10011(g)(2))

(c) The owner or operator shall report the information as required in 40 CFR 63.10031. (40 CFR 63.10011(g)(3))

(d) If you choose to use paragraph (2) of the definition of "startup" in 40 CFR 63.10042 and you find that you are unable to safely engage and operate your particulate matter (PM) control(s) within 1 hour of first firing of coal, residual oil, or solid oil-derived fuel, you may choose to rely on paragraph (1) of definition of "startup" in 40 CFR 63.10042 or you may submit a request to use an alternative non-opacity emissions standard, as described below. (40 CFR 63.10011(g)(4))

(i) As mentioned in 40 CFR 63.6(g)(1), your request will be published in the *Federal Register* for notice and comment rulemaking. Until promulgation in the *Federal Register* of the final alternative non-opacity emission standard, you shall comply with paragraph (1) of the definition of "startup" in 40 CFR 63.10042. You shall not implement the alternative non-opacity emissions standard until promulgation in the *Federal Register* of the final alternative non-opacity emission standard. (40 CFR 63.10011(g)(4)(i))

(ii) The owner or operator's request need not address the items contained in 40 CFR 63.6(g)(2). (40 CFR 63.10011(g)(4)(ii))

(iii) The owner or operator's request shall provide evidence of a documented manufacturer-identified safety issue. (40 CFR 63.10011(g)(4)(iii))

(iv) The owner or operator's request shall provide information to document that the PM control device is adequately designed and sized to meet the PM emission limit applicable to the EGU. (40 CFR 63.10011(g)(4)(iv))

(v) In addition, your request shall contain documentation that: (40 CFR 63.10011(g)(4)(v))

(A) The owner or operator's EGU is using clean fuels to the maximum extent possible, taking into account considerations such as not compromising boiler or control device integrity, to bring your EGU and PM control device up to the temperature necessary to alleviate or prevent the identified safety issues prior to the combustion of primary fuel in your EGU; (40 CFR 63.10011(g)(4)(v)(A))

(B) The owner or operator has followed explicitly your EGU manufacturer's procedures to alleviate or prevent the identified safety issue; and (40 CFR 63.10011(g)(4)(v)(B))

(C) The owner or operator has identified with specificity the details of your EGU manufacturer's statement of concern. (40 CFR 63.10011(g)(4)(v)(C))

(vi) The owner or operator's request shall specify the other work practice standards you will take to limit HAP emissions during startup periods and shutdown periods to ensure a control level consistent with the work practice standards of the final rule. (40 CFR 63.10011(g)(4)(vi))

(vii) The owner or operator shall comply with all other work practice requirements, including but not limited to data collection, recordkeeping, and reporting requirements. (40 CFR 63.10011(g)(4)(vii))

Continuous Compliance Requirements:

vii. Monitor and collect data to demonstrate continuous compliance: (40 CFR 63.10020)

1) The owner or operator shall monitor and collect data according to this section and the site-specific monitoring plan required by 40 CFR 63.10000(d). (40 CFR 63.10020(a))

2) The owner or operator shall operate the monitoring system and collect data at all required intervals at all times that the affected EGU is operating, except for periods of monitoring system malfunctions or out-of-control periods (see 40 CFR 63.8(c)(7) of this part), and required monitoring system quality assurance or quality control activities, including, as applicable, calibration checks and required zero and span adjustments. The owner or operator is required to affect monitoring system repairs in response to monitoring system malfunctions and to return the monitoring system to operation as expeditiously as practicable. (40 CFR 63.10020(b))

3) The owner or operator may not use data recorded during EGU startup or shutdown or monitoring system malfunctions or monitoring system out-of-control periods, repairs associated with monitoring system malfunctions or monitoring system out-of-control periods, or required monitoring system quality assurance or control activities in calculations used to report emissions or operating levels. The owner or operator shall use all the data collected during all other periods in assessing the operation of the control device and associated control system. (40 CFR 63.10020(c))

4) Except for periods of monitoring system malfunctions or monitoring system out-of-control periods, repairs associated with monitoring system malfunctions or monitoring system out-of-control periods, and required monitoring system quality assurance or quality control activities including, as applicable, calibration checks and required zero and span adjustments), failure to collect required data is a deviation from the monitoring requirements. (40 CFR 63.10020(d))

5) Additional requirements during startup periods or shutdown periods if you choose to rely on paragraph (2) of the definition of "startup" in 40 CFR 63.10042 for your EGU. (40 CFR 63.10020(e))

(a) During each period of startup, you must record for each EGU: (40 CFR 63.10020(e)(1))

(i) The date and time that clean fuels being combusted for the purpose of startup begins; (40 CFR

63.10020(e)(1)(i))

(ii) The quantity and heat input of clean fuel for each hour of startup; (40 CFR 63.10020(e)(1)(ii))

(iii) The gross output for each hour of startup; (40 CFR 63.10020(e)(1)(iii))

(iv) The date and time that non-clean fuel combustion begins; and (40 CFR 63.10020(e)(1)(iv))

(v) The date and time that clean fuels being combusted for the purpose of startup ends. (40 CFR 63.10020(e)(1)(v))

(b) During each period of shutdown, you must record for each EGU: (40 CFR 63.10020(e)(2))

(i) The date and time that clean fuels being combusted for the purpose of shutdown begins; (40 CFR 63.10020(e)(2)(i))

(ii) The quantity and heat input of clean fuel for each hour of shutdown; (40 CFR 63.10020(e)(2)(ii))

(iii) The gross output for each hour of shutdown; (40 CFR 63.10020(e)(2)(iii))

(iv) The date and time that non-clean fuel combustion ends; and (40 CFR 63.10020(e)(2)(iv))

(v) The date and time that clean fuels being combusted for the purpose of shutdown ends. (40 CFR 63.10020(e)(2)(v))

(c) For PM or non-mercury HAP metals work practice monitoring during startup periods, you must monitor and collect data according to this section and the site-specific monitoring plan required by 40 CFR 63.10010(l). (40 CFR 63.10020(e)(3))

(i) Except for an EGU that uses PM CEMS or PM CPMS to demonstrate compliance with the PM emissions limit, or that has LEE status for filterable PM or total non-Hg HAP metals for non- liquid oil-fired EGUs (or HAP metals emissions for liquid oil-fired EGUs), or individual non-mercury metals CEMS, you must: (40 CFR 63.10020(e)(3)(i))

(A) Record temperature and combustion air flow or calculated flow as determined from combustion equations of post-combustion (exhaust) gas, as well as amperage of forced draft fan(s), upstream of the filterable PM control devices during each hour of startup. (40 CFR 63.10020(e)(3)(i)(A))

(B) Record temperature and flow of exhaust gas, as well as amperage of any induced draft fan(s), downstream of the filterable PM control devices during each hour of startup. (40 CFR 63.10020(e)(3)(i)(B))

(C) For an EGU with an electrostatic precipitator, record the number of fields in service, as well as each field's secondary voltage and secondary current during each hour of startup. (40 CFR 63.10020(e)(3)(i)(C))

(D) For an EGU with a fabric filter, record the number of compartments in service, as well as the differential pressure across the baghouse during each hour of startup. (40 CFR 63.10020(e)(3)(i)(D))

(E) For an EGU with a wet scrubber needed for filterable PM control, record the scrubber liquid to flue gas ratio and the pressure drop across the scrubber during each hour of startup. (40 CFR 63.10020(e)(3)(i)(E))

viii. Demonstrate continuous compliance with the emission limitations, operating limits, and work practice standards: (40 CFR 63.10021)

1) The owner or operator shall demonstrate continuous compliance with each emissions limit, operating limit, and work practice standard in Tables 1 through 4 to 40 CFR 63, Subpart UUUUU that applies to the owner or operator, according to the monitoring specified in Tables 6 and 7 to 40 CFR 63, Subpart UUUUU and paragraphs (b) through (g) of this section. (40 CFR 63.10021(a))

2) Except as otherwise provided in 40 CFR 63.10020(c), if the owner or operator uses a CEMS to measure SO_2, PM, HCl, HF, or Hg emissions, or using a sorbent trap monitoring system to measure Hg emissions, the owner or operator shall demonstrate continuous compliance by using all quality-assured hourly data recorded by the CEMS (or sorbent trap monitoring system) and the other required monitoring systems (e.g., flow rate, CO_2, O_2, or moisture systems) to calculate the arithmetic average emissions rate in units of the standard on a continuous 30–boiler operating day (or, if alternate emissions averaging is used for Hg, 90- boiler operating day) rolling average basis, updated at the end of each new boiler operating day. Use Equation 8 to determine the 30– (or, if applicable, 90-) boiler operating day rolling average. (40 CFR 63.10021(b))

$$\textit{Boiler operating day average} = \frac{\sum_{i=1}^{n} \mathrm{Her}_i}{n} \quad \text{(Eq.8)}$$

Where:
Her_i is the hourly emissions rate for hour i and n is the number of hourly emissions rate values collected over 30- (or, if applicable, 90-) boiler operating days.

3) If the owner or operator uses a PM CPMS data to measure compliance with an operating limit in Table 4 to 40 CFR 63, Subpart UUUUU, the owner or operator shall record the PM CPMS output data for all periods when the process is operating and the PM CPMS is not out-of-control. The owner or operator shall demonstrate continuous compliance by using all quality-assured hourly average data collected by the PM CPMS for all operating hours to calculate the arithmetic average operating parameter in units of the operating limit (*e.g.*, milliamps, PM concentration, raw data signal) on a 30 operating day rolling average basis, updated at the end of each new boiler operating day. Use Equation 9 to determine the 30 boiler operating day average. (40 CFR 63.10021(c))

$$30\ \textit{boiler operating day average} = \frac{\sum_{i=1}^{n} \mathrm{Hpv}_i}{n} \quad \text{(Eq.9)}$$

Where:
Hpv_i is the hourly parameter value for hour i and n is the number of valid hourly parameter values collected over 30 boiler operating days.

4) If the owner or operator use quarterly performance testing to demonstrate compliance with one or more applicable emissions limits in Table 1 or 2 to 40 CFR 63, Subpart UUUUU, the owner or operator (40 CFR 63.10021(d))

(a) May skip performance testing in those quarters during which less than 168 boiler operating hours occur, except that a performance test must be conducted at least once every calendar year. (40 CFR 63.10021(d)(1))

(b) Must conduct the performance test as defined in Table 5 to 40 CFR 63, Subpart UUUUU and calculate the results of the testing in units of the applicable emissions standard; and (40 CFR 63.10021(d)(2))

(c) Must conduct site-specific monitoring using CMS to demonstrate compliance with the site-specific monitoring requirements in Table 7 to this subpart pertaining to HCl and HF emissions from a liquid oil-fired unit to ensure compliance with the HCl and HF emission limits in Tables 1 and 2 to 40 CFR 63, Subpart UUUUU, in accordance with the requirements of 40 CFR 63.10000(c)(2)(iii). The monitoring must meet the general operating requirements provided in 40 CFR 63.10020(a). (40 CFR 63.10021(d)(3))

5) Conduct periodic performance tune-ups of the EGU(s), as specified in paragraphs (e)(1) through (9) of this section. For the first tune-up, the owner or operator may perform the burner inspection any time prior to the tune-up or the owner or operator may delay the first burner inspection until the next scheduled EGU outage provided the owner or operator meet the requirements of 40 CFR 63.10005. Subsequently, the owner or operator shall perform an inspection of the burner at least once every 36 calendar months unless the EGU employs neural network combustion optimization during normal operations in which case the owner or operator shall perform an inspection of the burner and combustion controls at least once every 48 calendar months. If your EGU is offline when a deadline to perform the tune-up passes, you shall perform the tune-up work practice requirements within 30 days after the re-start of the affected unit. (40 CFR 63.10021(e))

(a) As applicable, inspect the burner and combustion controls, and clean or replace any components of the burner or combustion controls as necessary upon initiation of the work practice program and at least once every required inspection period. Repair of a burner or combustion control component requiring special order parts may be scheduled as follows: (40 CFR 63.10021(e)(1))

(i) Burner or combustion control component parts needing replacement that affect the ability to optimize NO_x and CO must be installed within 3 calendar months after the burner inspection, (40 CFR 63.10021(e)(1)(i))

(ii) Burner or combustion control component parts that do not affect the ability to optimize NO_x and CO may be installed on a schedule determined by the operator; (40 CFR 63.10021(e)(1)(ii))

(b) As applicable, inspect the flame pattern and make any adjustments to the burner or combustion controls necessary to optimize the flame pattern. The adjustment should be consistent with the manufacturer's specifications, if available, or in accordance with best combustion engineering practice for that burner type; (40 CFR 63.10021(e)(2))

(c) As applicable, observe the damper operations as a function of mill and/or cyclone loadings, cyclone and pulverizer coal feeder loadings, or other pulverizer and coal mill performance parameters, making adjustments and effecting repair to dampers, controls, mills, pulverizers, cyclones, and sensors; (40 CFR 63.10021(e)(3))

(d) As applicable, evaluate windbox pressures and air proportions, making adjustments and effecting repair to dampers, actuators, controls, and sensors; (40 CFR 63.10021(e)(4))

(e) Inspect the system controlling the air-to-fuel ratio and ensure that it is correctly calibrated and functioning properly. Such inspection may include calibrating excess O_2 probes and/or sensors, adjusting overfire air systems, changing software parameters, and calibrating associated actuators and dampers to ensure that the systems are operated as designed. Any component out of calibration, in or near failure, or in a state that is likely to negate combustion optimization efforts prior to the next tune-up, should be corrected or repaired as necessary; (40 CFR 63.10021(e)(5))

(f) Optimize combustion to minimize generation of CO and NO_X. This optimization should be consistent with the manufacturer's specifications, if available, or best combustion engineering practice for the applicable burner type. NO_X optimization includes burners, overfire air controls, concentric firing system improvements, neural network or combustion efficiency software, control systems calibrations, adjusting combustion zone temperature profiles, and add-on controls such as SCR and SNCR; CO optimization includes burners, overfire air controls, concentric firing system improvements, neural network or combustion efficiency software, control systems calibrations, and adjusting combustion zone temperature profiles; (40 CFR 63.10021(e)(6))

(g) While operating at full load or the predominantly operated load, measure the concentration in the effluent stream of CO and NO_x in ppm, by volume, and oxygen in volume percent, before and after the tune-up 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). The owner or operator may use portable CO, NO_x and O_2 monitors for this measurement. EGU's employing neural network optimization systems need only provide a single pre- and post-tune-up value rather than continual values before and after each optimization adjustment made by the system; (40 CFR 63.10021(e)(7))

(h) Maintain on-site and submit, if requested by the Administrator, an annual report containing the information in paragraphs (e)(1) through (e)(9) of this section including: (40 CFR 63.10021(e)(8))

(i) The concentrations of CO and NO_x in the effluent stream in ppm by volume, and oxygen in volume percent, measured before and after an adjustment of the EGU combustion systems; (40 CFR 63.10021(e)(8)(i))

(ii) A description of any corrective actions taken as a part of the combustion adjustment; and (40 CFR 63.10021(e)(8)(ii))

(iii) The type(s) and amount(s) of fuel used over the 12 calendar months prior to an adjustment, but only if the unit was physically and legally capable of using more than one type of fuel during that period; and (40 CFR 63.10021(e)(8)(iii))

(i) Report the dates of the initial and subsequent tune-ups in hard copy, as specified in 40 CFR 63.10031(f)(5), until April 16, 2017. After April 16, 2017, report the date of all tune-ups electronically, in accordance with 40 CFR 63.10031(f).

The tune-up report date is the date when tune-up requirements in paragraphs (e)(6) and (7) of this section are completed. (40 CFR 63.10021(e)(9))

6) The owner or operator shall submit the reports required under 40 CFR 63.10031 and, if applicable, the reports required under appendices A and B to 40 CFR 63, Subpart UUUUU. The electronic reports required by appendices A and B to 40 CFR 63, Subpart UUUUU must be sent to the Administrator electronically in a format prescribed by the Administrator, as provided in 40 CFR 63.10031. CEMS data (except for PM CEMS and any approved alternative monitoring using a HAP metals CEMS) shall be submitted using EPA's Emissions Collection and Monitoring Plan System (ECMPS) Client Tool. Other data, including PM CEMS data, HAP metals CEMS data, and CEMS performance test detail reports, shall be submitted in the file format generated through use of EPA's Electronic Reporting Tool, the Compliance and Emissions Data Reporting Interface, or alternate electronic file format, all as provided for under 40 CFR63.10031. (40 CFR 63.10021(f))

7) The owner or operator shall report each instance in which the owner or operator did not meet an applicable emissions limit or operating limit in Tables 1 through 4 to 40 CFR 63, Subpart UUUUU or failed to conduct a required tune-up. These instances are deviations from the requirements of 40 CFR 63, Subpart UUUUU. These deviations must be reported according to 40 CFR 63.10031. (40 CFR 63.10021(g))

8) The owner or operator shall follow the startup or shutdown requirements as given in Table 3 to this subpart for each coal-fired, liquid oil-fired, or solid oil-derived fuel-fired EGU. (40 CFR 63.10021(h))

(a) The owner or operator use the diluent cap and default gross output values, as described in 40 CFR 63.10007(f), during startup periods or shutdown periods. (40 CFR 63.10021(h)(1))

(b) The owner or operator shall operate all CMS, collect data, calculate pollutant emission rates, and record data during startup periods or shutdown periods. (40 CFR 63.10021(h)(2))

(c) The owner or operator shall report the information as required in 40 CFR 63.10031. (40 CFR 63.10021(h)(3))

(d) The owner or operator may choose to submit an alternative non-opacity emission standard, in accordance with the requirements contained in 40 CFR 63.10011(g)(4). Until promulgation in the *Federal Register* of the final alternative non-opacity emission standard, you shall comply with paragraph (1) of the definition of "startup" in 40 CFR 63.10042. (40 CFR 63.10021(h)(4))

9) The owner or operator shall provide reports as specified in 40 CFR 63.10031 concerning activities and periods of startup and shutdown. (40 CFR 63.10021(i))

ix. Demonstrate continuous compliance under the emissions averaging provision: (40 CFR 63.10022)

1) Following the compliance date, the owner or operator must demonstrate compliance with 40 CFR 63, Subpart UUUUU on a continuous basis by meeting the requirements of paragraphs (a)(1) through (3) of this section. (40 CFR 63.10022(a))

(a) For each 30- (or 90-) day rolling average period, demonstrate compliance with the average weighted emissions limit for the existing units participating in the emissions averaging option as determined in 40 CFR 63.10009(f) and (g); (40 CFR 63.10022(a)(1))

(b) For each existing unit participating in the emissions averaging option that is equipped with PM CPMS, maintain the average parameter value at or below the operating limit established during the most recent performance test; (40 CFR 63.10022(a)(2))

(c) For each existing unit participating in the emissions averaging option venting to a common stack configuration containing affected units from other subcategories, maintain the appropriate operating limit for each unit as specified in Table 4 to 40 CFR 63, Subpart UUUUU that applies. (40 CFR 63.10022(a)(3))

2) Any instance where the owner or operator fails to comply with the continuous monitoring requirements in paragraphs (a)(1) through (3) of this section is a deviation. (40 CFR 63.10022(b))

x. Establish PM CPMS operating limit and determine compliance with it: (40 CFR 63.10023)

1) During the initial performance test or any such subsequent performance test that demonstrates compliance with the filterable PM, individual non-mercury HAP metals, or total non-mercury HAP metals limit (or for liquid oil-fired units, individual HAP metals or total HAP metals limit, including Hg) in Table 1 or 2, record all hourly average output values (e.g., milliamps, stack concentration, or other raw data signal) from the PM CPMS for the periods corresponding to the test runs (e.g., nine 1–hour average PM CPMS output values for three 3–hour test runs). (40 CFR 63.10023(a))

2) Determine your operating limit as provided in paragraph (b)(2) of this section. You must verify an existing or establish a new operating limit after each repeated performance test. (40 CFR 63.10023(b))

(a) Determine your operating limit as follows: (40 CFR 63.10023(b)(2))

(i) If your PM performance test demonstrates your PM emissions do not exceed 75 percent of your emissions limit, you will use the average PM CPMS value recorded during the PM compliance test, the milliamp equivalent of zero output from your PM CPMS, and the average PM result of your compliance test to establish your operating limit. Calculate the operating limit by establishing a relationship of PM CPMS signal to PM concentration using the PM CPMS instrument zero, the average PM CPMS values corresponding to the three compliance test runs, and the average PM concentration from the Method 5 compliance test with the procedures in (b)(2)(i)(A) through (D) of this section. (40 CFR 63.10023(b)(2)(i))

(A) Determine your PM CPMS instrument zero output with one of the following procedures. (40 CFR 63.10023(b)(2)(i)(A))

- Zero point data for in-situ instruments should be obtained by removing the instrument from the stack and monitoring ambient air on a test bench. (40 CFR 63.10023(b)(2)(i)(A)(1))
- Zero point data for extractive instruments should be obtained by removing the extractive probe from the stack and drawing in clean

ambient air. (40 CFR 63.10023(b)(2)(i)(A)(2))

- The zero point can also can be obtained by performing manual reference method measurements when the flue gas is free of PM emissions or contains very low PM concentrations (e.g., when your process is not operating, but the fans are operating or your source is combusting only natural gas) and plotting these with the compliance data to find the zero intercept. (40 CFR 63.10023(b)(2)(i)(A)(3))
- If none of the steps in paragraphs (A)(1) through (3) of this section are possible, you must use a zero output value provided by the manufacturer. (40 CFR 63.10023(b)(2)(i)(A)(4))

(B) Determine your PM CPMS instrument average (x) in milliamps, and the average of your corresponding three PM compliance test runs (y), using equation 10. (40 CFR 63.10023(b)(2)(i)(B))

$$\bar{x} = \frac{1}{n}\sum_{i=1}^{n} X_i, \bar{y} = \frac{1}{n}\sum_{i=1}^{n} Y_i \qquad \text{(Eq. 10)}$$

Where:
Xi = the PM CPMS data points for run i of the performance test,
Yi = the PM emissions value (in lb/MWh) for run i of the performance test, and
n = the number of data points.

(C) With your PM CPMS instrument zero expressed in milliamps, your three run average PM CPMS milliamp value, and your three run average PM emissions value (in lb/MWh) from your compliance runs, determine a relationship of PM lb/MWh per milliamp with equation 11. (40 CFR 63.10023(b)(2)(i)(C))

$$R = \frac{y}{(x - z)} \quad \text{(Eq. 11)}$$

Where:
R = the relative PM lb/MWh per milliamp for your PM CPMS,
ȳ = the three run average PM lb/MWh,
x̄ = the three run average milliamp output from your PM CPMS, and
z = the milliamp equivalent of your instrument zero determined from (b)(2)(i)(A) of this section.

(D) Determine your source specific 30-day rolling average operating limit using the PM lb/MWh per milliamp value from equation 11 in equation 12, below. This sets your operating limit at the PM CPMS output value corresponding to 75 percent of your emission limit. (40 CFR 63.10023(b)(2)(i)(D))

$$O_L = z + \frac{(0.75 \times L)}{R} \quad \text{(Eq. 12)}$$

Where:
OL = the operating limit for your PM CPMS on a 30-day rolling average, in milliamps,
L = your source PM emissions limit in lb/MWh,
z = your instrument zero in milliamps, determined from (b)(2)(i)(A) of this section, and
R = the relative PM lb/MWh per milliamp for your PM CPMS, from equation 11.

(ii) If your PM compliance test demonstrates your PM emissions exceed 75 percent of your emissions limit, you will use the average PM CPMS value recorded during the PM compliance test demonstrating compliance with the PM limit to establish your operating limit. (40 CFR 63.10023(b)(2)(ii))

(A) Determine your operating limit by averaging the PM CPMS milliamp output corresponding to your three PM performance test runs that demonstrate compliance with the emission limit using equation 13. (40 CFR 63.10023(b)(2)(ii)(A))

$$O_h = \frac{1}{n}\sum_{i=1}^{n} X_i \quad \text{(Eq. 13)}$$

Where:
Xi = the PM CPMS data points for all runs i,
n = the number of data points, and
Oh = your site specific operating limit, in milliamps.

(iii) Your PM CPMS must provide a 4-20 milliamp output and the establishment of its relationship to manual reference method measurements must be determined in units of milliamps. (40 CFR 63.10023(b)(2)(iii))

(iv) Your PM CPMS operating range must be capable of reading PM concentrations from zero to a level equivalent to two times your allowable emission limit. If your PM CPMS is an auto-ranging instrument capable of multiple scales, the primary range of the instrument must be capable of reading PM concentration from zero to a level equivalent to two times your allowable emission limit. (40 CFR 63.10023(b)(2)(iv))

(v) During the initial performance test or any such subsequent performance test that demonstrates compliance with the PM limit, record and average all milliamp output values from the PM CPMS for the periods corresponding to the compliance test runs. (40 CFR 63.10023(b)(2)(v))

(vi) For PM performance test reports used to set a PM CPMS operating limit, the electronic submission of the test report must also include the make and model of the PM CPMS instrument, serial number of the instrument, analytical principle of the instrument (e.g. beta attenuation), span of the instruments primary analytical range, milliamp value equivalent to the instrument zero output, technique by which this zero value was determined, and the average milliamp signal corresponding to each PM compliance test run. (40 CFR 63.10023(b)(2)(vi))

3) The owner or operator shall operate and maintain the process and control equipment such that the 30 operating day average PM CPMS

output does not exceed the operating limit determined in paragraphs (a) and (b) of this section. (40 CFR 63.10023(c))

xi. Record keeping requirements: (40 CFR 63.10032)

1) The owner or operator shall keep records according to paragraphs (a)(1) and (2) of this section. If the owner or operator is required to (or elect to) continuously monitor Hg and/or HCl and/or HF emissions, the owner or operator shall also keep the records required under appendix A and/or appendix B to 40 CFR 63, Subpart UUUUU. (40 CFR 63.10032(a))

(a) A copy of each notification and report that the owner or operator submitted to comply with 40 CFR 63, Subpart UUUUU, including all documentation supporting any Initial Notification or Notification of Compliance Status or compliance report that the owner or operator submitted, according to the requirements in 40 CFR 63.10 (b)(2)(xiv). (40 CFR 63.10032(a)(1))

(b) Records of performance stack tests, fuel analyses, or other compliance demonstrations and performance evaluations, as required in 40 CFR 63.10 (b)(2)(viii). (40 CFR 63.10032(a)(2))

2) For each CEMS and CPMS, the owner or operator shall keep records according to paragraphs (b)(1) through (4) of this section. (40 CFR 63.10032(b))

(a) Records described in 40 CFR 63.10(b)(2)(vi) through (xi). (40 CFR 63.10032(b)(1))

(b) Previous (i.e., superseded) versions of the performance evaluation plan as required in 40 CFR 63.8(d)(3). (40 CFR 63.10032(b)(2))

(c) Request for alternatives to relative accuracy test for CEMS as required in 40 CFR 63.8(f)(6)(i). (40 CFR 63.10032(b)(3))

(d) Records of the date and time that each deviation started and stopped and whether the deviation occurred during a period of startup, shutdown, or malfunction or during another period. (40 CFR 63.10032(b)(4))

3) The owner or operator shall keep the records required in Table 7 to 40 CFR 63, Subpart UUUUU including records of all monitoring data and calculated averages for applicable PM CPMS operating limits to show continuous compliance with each emission limit and operating limit that applies to the owner or operator. (40 CFR 63.10032(c))

Table 7 to Subpart UUUUU of Part 63 - Demonstrating Continuous Compliance [As stated in 40 CFR63.10021. The owner or operator shall show continuous compliance with the emission limitations for affected sources according to the following]

If the owner or operator uses one of the following to meet applicable emissions limits, operating limits, or work practice standards . . .	**The owner or operator demonstrate continuous compliance by . . .**
1. CEMS to measure filterable PM, SO_2 , HCl, HF, or Hg emissions, or using a sorbent trap monitoring system to measure Hg	Calculating the 30- (or 90-) boiler operating day rolling arithmetic average emissions rate in units of the applicable emissions standard basis at the end of each boiler operating day using all of the quality assured hourly average CEMS or sorbent trap data for the previous 30- (or 90-) boiler operating days, excluding data recorded during periods of startup or shutdown.
2. PM CPMS to measure compliance with a parametric operating limit	Calculating the 30- (or 90-) boiler operating day rolling arithmetic average of all of the quality assured hourly average PM CPMS output data (e.g., milliamps, PM concentration, raw data signal) collected for all operating hours for the previous 30- (or 90-) boiler operating days, excluding data recorded during periods of startup or shutdown.
3. Site-specific monitoring using CMS for liquid oil-fired EGUs for HCl and HF emission limit monitoring	If applicable, by conducting the monitoring in accordance with an approved site-specific monitoring plan.
4. Quarterly performance testing for coal-fired, solid oil derived fired, or liquid oil-fired EGUs to measure compliance with one or more non-PM (or its alternative emission limits) applicable emissions limit in Table 1 or 2, or PM (or its alternative emission limits) applicable emissions limit in Table 2	Calculating the results of the testing in units of the applicable emissions standard.
5. Conducting periodic performance tune-ups of your EGU(s)	Conducting periodic performance tune-ups of your EGU(s), as specified in 40 CFR 63.10021(e).
6. Work practice standards for coal-fired, liquid oil-fired, or solid oil-derived fuel-fired EGUs during startup	Operating in accordance with Table 3.
7. Work practice standards for coal-fired, liquid oil-fired, or solid oil-derived fuel-fired EGUs during shutdown	Operating in accordance with Table 3.

4) For each EGU subject to an emission limit, the owner or operator shall also keep the records in paragraphs (d)(1) through (3) of this section. (40 CFR 63.10032(d))

(a) The owner or operator shall keep records of monthly fuel use by each EGU, including the type(s) of fuel and amount(s) used. (40 CFR 63.10032(d)(1))

(b) If the owner or operator combusts non-hazardous secondary materials that have been determined not to be solid waste pursuant to 40 CFR 241.3(b)(1), the owner or operator shall keep a record which documents how the secondary material meets each of the legitimacy criteria. If the owner or operator combusts a fuel that has been processed from a discarded non-hazardous secondary material pursuant to 40 CFR 241.3(b)(2), the owner or operator shall keep records as to how the operations that produced the fuel satisfies the definition of processing in 40 CFR 241.2. If the fuel received a non-waste determination pursuant to the petition process submitted under 40 CFR 241.3(c), the owner or operator shall keep a record which documents how the fuel satisfies the requirements of the petition process. (40 CFR 63.10032(d)(2))

(c) For an EGU that qualifies as an LEE under 40 CFR 63.10005(h), the owner or operator shall keep annual records that document that the emissions in the previous stack test(s) continue to qualify the unit for LEE status for an applicable pollutant, and document that there was no change in source operations including fuel composition and operation of air pollution control equipment that would cause emissions of the pollutant to increase within the past year. (40 CFR 63.10032(d)(3))

5) If the owner or operator elects to average emissions consistent with 40 CFR 63.10009, the owner or operator shall additionally keep a copy of the emissions averaging implementation plan required in 40 CFR 63.10009(g), all calculations required under 40 CFR 63.10009, including daily records of heat input or steam generation, as applicable, and monitoring records consistent with 40 CFR 63.10022. (40 CFR 63.10032(e))

6) Regarding startup periods or shutdown periods: (40 CFR 63.10032(f))

(a) Should you choose to rely on paragraph (1) of the definition of "startup" in 40 CFR 63.10042 for your EGU, you must keep records of the occurrence and duration of each startup or shutdown. (40 CFR 63.10032(f)(1))

(b) Should you choose to rely on paragraph (2) of the definition of "startup" in 40 CFR 63.10042 for your EGU, you must keep records of: (40 CFR 63.10032(f)(2))

(i) The determination of the maximum possible clean fuel capacity for each EGU; (40 CFR 63.10032(f)(2)(i))

(ii) The determination of the maximum possible hourly clean fuel heat input and of the hourly clean fuel heat input for each EGU; and (40 CFR 63.10032(f)(2)(ii))

(iii) The information required in 40 CFR 63.10020(e). (40 CFR 63.10032(f)(2)(iii))

7) The owner or operator shall keep records of the occurrence and duration of each malfunction of an operation (i.e., process equipment) or the air pollution control and monitoring equipment. (40 CFR 63.10032(g))

8) The owner or operator shall keep records of actions taken during periods of malfunction to minimize emissions in accordance with 40 CFR 63.10000(b), including corrective actions to restore malfunctioning process and air pollution control and monitoring equipment to its normal or usual manner of operation. (40 CFR 63.10032(h))

9) The owner or operator shall keep records of the type(s) and amount(s) of fuel used during each startup or shutdown. (40 CFR 63.10032(i))

10) If the owner or operator elects to establish that an EGU qualifies as a limited-use liquid oil-fired EGU, the owner or operator shall keep records of the type(s) and amount(s) of fuel use in each calendar quarter to document that the capacity factor limitation for that subcategory is met. (40 CFR 63.10032(j))

xii. Record keeping form and time period: (40 CFR 63.10033)

1) The owner or operator's records must be in a form suitable and readily available for expeditious review, according to 40 CFR 63.10(b)(1). (40 CFR 63.10033(a))

2) As specified in 40 CFR 63.10(b)(1), the owner or operator shall keep each record for 5 years following the date of each occurrence, measurement, maintenance, corrective action, report, or record. (40 CFR 63.10033(b))

3) The owner or operator shall keep each record on site for at least 2 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record, according to 40 CFR 63.10(b)(1). The owner or operator can keep the records off site for the remaining 3 years. (40 CFR 63.10033(c))

S3. **Reporting (Regulation 2.16, section 4.1.9.3)**

HAP

i. Notifications and date to submit the notifications: (40 CFR 63.10030)

1) The owner or operator shall submit all of the notifications in 40 CFR 63.7(b) and (c), 63.8 (e), (f)(4) and (6), and 63.9 (b) through (h) that apply to the owner or operator by the dates specified. (40 CFR 63.10030(a))

2) As specified in 40 CFR 63.9(b)(2), if the owner or operator starts up the affected source before April 16, 2012, the owner or operator shall submit an Initial Notification not later than 120 days after April 16, 2012. (40 CFR 63.10030(b))

3) As specified in 40 CFR 63.9(b)(4) and (b)(5), if the owner or operator starts up the new or reconstructed affected source on or after April 16, 2012, the owner or operator shall submit an Initial Notification not later than 15 days after the actual date of startup of the affected source. (40 CFR 63.10030(c))

4) When the owner or operator is required to conduct a performance test, the owner or operator shall submit a Notification of Intent to conduct a performance test at least 30 days before the performance test is scheduled to begin. (40 CFR 63.10030(d))

5) When the owner or operator is required to conduct an initial compliance demonstration as specified in 40 CFR 63.10011(a), the owner or operator shall submit a Notification of Compliance Status

according to 40 CFR 63.9(h)(2)(ii). The Notification of Compliance Status report must contain all the information specified in paragraphs (e)(1) through (7), as applicable. (40 CFR 63.10030(e))

(a) A description of the affected source(s) including identification of the subcategory of the source, the design capacity of the source, a description of the add-on controls used on the source, description of the fuel(s) burned, including whether the fuel(s) were determined by the owner or operator or EPA through a petition process to be a non-waste under 40 CFR 241.3, whether the fuel(s) were processed from discarded non-hazardous secondary materials within the meaning of 40 CFR 241.3, and justification for the selection of fuel(s) burned during the performance test. (40 CFR 63.10030(e)(1))

(b) Summary of the results of all performance tests and fuel analyses and calculations conducted to demonstrate initial compliance including all established operating limits. (40 CFR 63.10030(e)(2))

(c) Identification of whether the owner or operator plans to demonstrate compliance with each applicable emission limit through performance testing; fuel moisture analyses; performance testing with operating limits (e.g., use of PM CPMS); CEMS; or a sorbent trap monitoring system. (40 CFR 63.10030(e)(3))

(d) Identification of whether the owner or operator plans to demonstrate compliance by emissions averaging. (40 CFR 63.10030(e)(4))

(e) A signed certification that the owner or operator has met all applicable emission limits and work practice standards. (40 CFR 63.10030(e)(5))

(f) If the owner or operator had a deviation from any emission limit, work practice standard, or operating limit, the owner or operator shall also submit a brief description of the deviation, the duration of the deviation, emissions point identification and the cause of the deviation in the Notification of Compliance Status report. (40 CFR 63.10030(e)(6))

(g) In addition to the information required in 40 CFR 63.9(h)(2), the notification of compliance status must include the following: (40 CFR 63.10030(e)(7))

(i) A summary of the results of the annual performance tests and documentation of any operating limits that were reestablished during this test, if applicable. If the owner or operator is conducting stack tests once every 3 years consistent with 40 CFR 63.10006(b), the date of each stack test conducted during the previous 3 years, a comparison of the emission level the owner or operator achieved in each stack test conducted during the previous 3 years to the 50 percent emission limit threshold required in 40 CFR 63.10006(i), and a statement as to whether there have been any operational changes since the last stack test that could increase emissions. (40 CFR 63.10030(e)(7)(i))

(ii) Certifications of compliance, as applicable, and must be signed by a responsible official stating: (40 CFR 63.10030(e)(7)(ii))

(A) "This EGU complies with the requirements in 40 CFR 63.10021(a) to demonstrate continuous compliance." And (40 CFR 63.10030(e)(7)(ii)(A))

(B) "No secondary materials that are solid waste were combusted in any affected unit." (40 CFR 63.10030(e)(7)(ii)(B))

(iii) For each of your existing EGUs, identification of each emissions limit as specified in Table 2 to this subpart with which you plan to comply. (40 CFR 63.10030(e)(7)(iii))

(A) You may switch from a mass per heat input to a mass per gross output limit (or vice-versa), provided that: (40 CFR 63.10030(e)(7)(iii)(A))

- You submit a request that identifies for each EGU or EGU emissions averaging group involved in the proposed switch both the current and proposed emission limit; (40 CFR 63.10030(e)(7)(iii)(A)(1))

- Your request arrives to the Administrator at least 30 calendar days prior to the date that the switch is proposed to occur; (40 CFR 63.10030(e)(7)(iii)(A)(2))
- Your request demonstrates through performance stack test results completed within 30 days prior to your submission, compliance for each EGU or EGU emissions averaging group with both the mass per heat input and mass per gross output limits; (40 CFR 63.10030(e)(7)(iii)(A)(3))
- You revise and submit all other applicable plans, *e.g.,* monitoring and emissions averaging, with your request; and (40 CFR 63.10030(e)(7)(iii)(A)(4))
- You maintain records of all information regarding your choice of emission limits. (40 CFR 63.10030(e)(7)(iii)(A)(5))

(B) You begin to use the revised emission limits starting in the next reporting period, after receipt of written acknowledgement from the Administrator of the switch. (40 CFR 63.10030(e)(7)(iii)(B))

(C) From submission of your request until start of the next reporting period after receipt of written acknowledgement from the Administrator of the switch, you demonstrate compliance with both the mass per heat input and mass per gross output emission limits for each pollutant for each EGU or EGU emissions averaging group. (40 CFR 63.10030(e)(7)(iii)(C))

(h) Identification of whether you plan to rely on paragraph (1) or (2) of the definition of “startup” in 40 CFR 63.10042. (40 CFR 63.10030(e)(8))

(i) Should you choose to rely on paragraph (2) of the definition of “startup” in 40 CFR 63.10042 for your EGU, you shall include a report that identifies: (40

CFR 63.10030(e)(8)(i))

(A) The original EGU installation date; (40 CFR 63.10030(e)(8)(i)(A))

(B) The original EGU design characteristics, including, but not limited to, fuel mix and PM controls; (40 CFR 63.10030(e)(8)(i)(B))

(C) Each design PM control device efficiency established during performance testing or while operating in periods other than startup and shutdown periods; (40 CFR 63.10030(e)(8)(i)(C))

(D) The design PM emission rate from the EGU in terms of pounds PM per MMBtu and pounds PM per hour established during performance testing or while operating in periods other than startup and shutdown periods; (40 CFR 63.10030(e)(8)(i)(D))

(E) The design time from start of fuel combustion to necessary conditions for each PM control device startup; (40 CFR 63.10030(e)(8)(i)(E))

(F) Each design PM control device efficiency upon startup of the PM control device, if different from the efficiency provided in paragraph (e)(8)(i)(C) of this section; (40 CFR 63.10030(e)(8)(i)(F))

(G) Current EGU PM producing characteristics, including, but not limited to, fuel mix and PM controls, if different from the characteristics provided in paragraph (e)(8)(i)(B) of this section; (40 CFR 63.10030(e)(8)(i)(G))

(H) Current PM control device efficiency from each PM control device, if different from the efficiency provided in paragraph (e)(8)(i)(C) of this section; (40 CFR 63.10030(e)(8)(i)(H))

(I) Current PM emission rate from the EGU in terms of pounds PM per MMBtu and pounds per hour, if different from the rate provided in paragraph (e)(8)(i)(D) of this section; (40 CFR 63.10030(e)(8)(i)(I))

(J) Current time from start of fuel combustion to conditions necessary for each PM control device startup, if different from the time provided in paragraph (e)(8)(i)(E) of this section; and (40 CFR 63.10030(e)(8)(i)(J))

(K) Current PM control device efficiency upon startup of each PM control device, if different from the efficiency provided in paragraph (e)(8)(i)(H) of this section. (40 CFR 63.10030(e)(8)(i)(K))

(ii) The report shall be prepared, signed, and sealed by a professional engineer licensed in the state where your EGU is located. (40 CFR 63.10030(e)(8)(ii))

(iii) You may switch from paragraph (1) of the definition of “startup” in § 63.10042 to paragraph (2) of the definition of “startup” (or vice-versa), provided that: (40 CFR 63.10030(e)(8)(iii))

(A) You submit a request that identifies for each EGU or EGU emissions averaging group involved in the proposed switch both the current definition of “startup” relied on and the proposed definition you plan to rely on; (40 CFR 63.10030(e)(8)(iii)(A))

(B) Your request arrives to the Administrator at least 30 calendar days prior to the date that the switch is proposed to occur; (40 CFR 63.10030(e)(8)(iii)(B))

(C) You revise and submit all other applicable plans, *e.g.,* monitoring and emissions averaging, with your submission; (40 CFR 63.10030(e)(8)(iii)(C))

(D) You maintain records of all information regarding your choice of the definition of "startup"; and (40 CFR 63.10030(e)(8)(iii)(D))

(E) You begin to use the revised definition of "startup" in the next reporting period after receipt of written acknowledgement from the Administrator of the switch. (40 CFR 63.10030(e)(8)(iii)(E))

6) You must submit the notifications in 40 CFR 63.10000(h)(2) and (i)(2) that may apply to you by the dates specified. (40 CFR 63.10030(f))

ii. Reports and the date to submit the reports: (40 CFR 63.10031)

1) The owner or operator shall submit each report in Table 8 to 40 CFR 63, Subpart UUUUU that applies to the owner or operator. If the owner or operator is required to (or elect to) continuously monitor Hg and/or HCl and/or HF emissions, the owner or operator shall also submit the electronic reports required under appendix A and/or appendix B to the subpart, at the specified frequency. (40 CFR 63.10031(a))

Table 8 to Subpart UUUUU of Part 63 - Reporting Requirements [As stated in 40 CFR63.10031. The owner or operator shall comply with the following requirements for reports]

The owner or operator shall submit a . . .	**The report must contain . . .**	**The owner or operator shall submit the report**
1. Compliance report …	a. Information required in 40 CFR 63.10031(c)(1) through (9); b. If there are no deviations from any emission limitation (emission limit and operating limit) that applies to the owner or operator and there are no deviations from the requirements for work practice standards in Table 3 to 40 CFR 63, Subpart UUUUU that apply to the owner or operator, a statement that there were no deviations from the emission limitations and work practice standards during the reporting period. If there were no periods during which the CMSs, including continuous emissions monitoring system, and operating parameter monitoring systems, were out-of control as specified in 40 CFR 63.8(c)(7), a statement that there were no periods during which the CMSs were out-of-control during the reporting period; and … c. If the owner or operator has a deviation from any emission limitation (emission limit and operating limit) or work practice standard during the reporting period, the report must	Semiannually according to the requirements in 40 CFR 63.10031(b).

The owner or operator shall submit a . . .	**The report must contain . . .**	**The owner or operator shall submit the report**
	contain the information in 40 CFR 63.10031(d). If there were periods during which the CMSs, including continuous emissions monitoring systems and continuous parameter monitoring systems, were out-of-control, as specified in 40 CFR 63.8(c) (7), the report must contain the information in 40 CFR 63.10031(e) …	

2) Unless the Administrator (APCD) has approved a different schedule for submission of reports under 40 CFR 63.10(a), the owner or operator shall submit each report by the date in Table 8 to 40 CFR 63, Subpart UUUUU and according to the requirements in paragraphs (b)(1) through (5) of this section. (40 CFR 63.10031(b))

(a) The first compliance report must cover the period beginning on the compliance date that is specified for the affected source in 40 CFR 63.9984 and ending on June 30 or December 31, whichever date is the first date that occurs at least 180 days after the compliance date that is specified for the source in 40 CFR 63.9984. (40 CFR 63.10031(b)(1))

(b) The first compliance report must be postmarked or submitted electronically no later than July 31 or January 31, whichever date is the first date following the end of the first calendar half after the compliance date that is specified for the source in 40 CFR 63.9984. (40 CFR 63.10031(b)(2))

(c) Each subsequent compliance report must cover the semiannual reporting period from January 1 through June 30 or the semiannual reporting period from July 1 through December 31. (40 CFR 63.10031(b)(3))

(d) Each subsequent compliance report must be postmarked or submitted electronically no later than July 31 or January 31, whichever date is the first date following the end of the semiannual reporting period. (40 CFR 63.10031(b)(4))

(e) For each affected source that is subject to permitting regulations pursuant to part 70 or part 71 of this chapter, and if the permitting authority has established dates for submitting semiannual reports pursuant to 40 CFR 70.6(a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A), the owner or operator may submit the first and subsequent compliance reports according to the dates the permitting authority has established instead of according to the dates in paragraphs (b)(1) through (4) of this section. (40 CFR 63.10031(b)(5))

3) The compliance report must contain the information required in paragraphs (c)(1) through (9) of this section. (40 CFR 63.10031(c))

(a) The information required by the summary report located in 63.10(e)(3)(vi). (40 CFR 63.10031(c)(1))

(b) The total fuel use by each affected source subject to an emission limit, for each calendar month within the semiannual reporting period, including, but not limited to, a description of the fuel, whether the fuel has received a non-waste determination by EPA or the basis for concluding that the fuel is not a waste, and the total fuel usage amount with units of measure. (40 CFR 63.10031(c)(2))

(c) Indicate whether the owner or operator burned new types of fuel during the reporting period. If the owner or operator did burn new types of fuel the owner or operator shall include the date of the performance test where that fuel was in use. (40 CFR 63.10031(c)(3))

(d) Include the date of the most recent tune-up for each EGU. The date of the tune-up is the date the tune-up provisions specified in 40 CFR 63.10021(e)(6) and (7) were completed. (40 CFR 63.10031(c)(4))

(e) Should you choose to rely on paragraph (2) of the definition of “startup” in § 63.10042 for your EGU, for each instance of startup or shutdown you shall: (40 CFR 63.10031(c)(5))

(i) Include the maximum clean fuel storage capacity and the maximum hourly heat input that can be provided for each clean fuel determined according to the requirements of 40 CFR 63.10032(f). (40 CFR 63.10031(c)(5)(i))

(ii) Include the information required to be monitored, collected, or recorded according to the requirements of 40 CFR 63.10020(e). (40 CFR 63.10031(c)(5)(i))

(iii) If you choose to use CEMS to demonstrate compliance with numerical limits, include hourly average CEMS values and hourly average flow values during startup periods or shutdown periods.

Use units of milligrams per cubic meter for PM CEMS values, micrograms per cubic meter for Hg CEMS values, and ppmv for HCl, HF, or SO_2 CEMS values. Use units of standard cubic meters per hour on a wet basis for flow values. (40 CFR 63.10031(c)(5)(iii))

(iv) If you choose to use a separate sorbent trap measurement system for startup or shutdown reporting periods, include hourly average mercury concentration values in terms of micrograms per cubic meter. (40 CFR 63.10031(c)(5)(iv))

(v) If you choose to use a PM CPMS, include hourly average operating parameter values in terms of the operating limit, as well as the operating parameter to PM correlation equation. (40 CFR 63.10031(c)(5)(v))

(f) You must report emergency bypass information annually from EGUs with LEE status. (40 CFR 63.10031(c)(6))

(g) A summary of the results of the annual performance tests and documentation of any operating limits that were reestablished during the test, if applicable. If you are conducting stack tests once every 3 years to maintain LEE status, consistent with 40 CFR 63.10006(b), the date of each stack test conducted during the previous 3 years, a comparison of emission level you achieved in each stack test conducted during the previous 3 years to the 50 percent emission limit threshold required in 40 CFR 63.10005(h)(1)(i), and a statement as to whether there have been any operational changes since the last stack test that could increase emissions. (40 CFR 63.10031(c)(7))

(h) A certification. (40 CFR 63.10031(c)(8))

(i) If you have a deviation from any emission limit, work practice standard, or operating limit, you must also submit a brief description of the deviation, the duration of the deviation, emissions point identification, and the cause of the deviation. (40 CFR 63.10031(c)(9))

4) For each excess emissions occurring at an affected source where the owner or operator is using a CMS to comply with that emission limit or operating limit, the owner or operator shall include the

information required in 40 CFR63.10(e)(3)(v) in the compliance report specified in section (c). (40 CFR 63.10031(d))

5) Each affected source that has obtained a Title V operating permit pursuant to part 70 or part 71 of this chapter must report all deviations as defined in 40 CFR 63, Subpart UUUUU in the semiannual monitoring report required by 40 CFR 70.6(a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A). If an affected source submits a compliance report pursuant to Table 8 to 40 CFR 63, Subpart UUUUU along with, or as part of, the semiannual monitoring report required by 40 CFR 70.6(a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A), and the compliance report includes all required information concerning deviations from any emission limit, operating limit, or work practice requirement in 40 CFR 63, Subpart UUUUU, submission of the compliance report satisfies any obligation to report the same deviations in the semiannual monitoring report. Submission of a compliance report does not otherwise affect any obligation the affected source may have to report deviations from permit requirements to the permit authority. (40 CFR 63.10031(e))

6) As of January 1, 2012, and within 60 days after the date of completing each performance test, the owner or operator shall submit the results of the performance tests required by 40 CFR 63, Subpart UUUUU to EPA's WebFIRE database by using the Compliance and Emissions Data Reporting Interface (CEDRI) that is accessed through EPA's Central Data Exchange (CDX) (www.epa.gov/cdx). Performance test data must be submitted in the file format generated through use of EPA's Electronic Reporting Tool (ERT) (see http://www.epa.gov/ttn/chief/ert/index.html). Only data collected using those test methods on the ERT Web site are subject to this requirement for submitting reports electronically to WebFIRE. Owners or operators who claim that some of the information being submitted for performance tests is confidential business information (CBI) must submit a complete ERT file including information claimed to be CBI on a compact disk or other commonly used electronic storage media (including, but not limited to, flash drives) to EPA. The electronic media must be clearly marked as CBI and mailed to U.S. EPA/OAPQS/CORE CBI Office, Attention: WebFIRE Administrator, MD C404–02, 4930 Old Page Rd., Durham, NC 27703. The same ERT file with the CBI omitted must be submitted to EPA via CDX as described earlier in this paragraph. At the discretion of the delegated authority, the owner or operator shall also submit these reports, including the confidential business information, to the delegated authority in the format specified by the delegated authority. (40 CFR 63.10031(f))

(a) Within 60 days after the date of completing each CEMS (SO_2, PM, HCl, HF, and Hg) performance evaluation test, as defined in 40 CFR 63.2 and required by 40 CFR 63, Subpart UUUUU, the owner or operator shall submit the relative accuracy test audit (RATA) data (or, for PM CEMS, RCA and RRA data) required by 40 CFR 63, Subpart UUUUU to EPA's WebFIRE database by using the Compliance and Emissions Data Reporting Interface (CEDRI) that is accessed through EPA's Central Data Exchange (CDX) (www.epa.gov/cdx). The RATA data shall be submitted in the file format generated through use of EPA's Electronic Reporting Tool (ERT) (http://www.epa.gov/ttn/chief/ert/index.html). Only RATA data compounds listed on the ERT Web site are subject to this requirement. Owners or operators who claim that some of the information being submitted for RATAs is confidential business information (CBI) shall submit a complete ERT file including information claimed to be CBI on a compact disk or other commonly used electronic storage media (including, but not limited to, flash drives) by registered letter to EPA and the same ERT file with the CBI omitted to EPA via CDX as described earlier in this paragraph. The compact disk or other commonly used electronic storage media shall be clearly marked as CBI and mailed to U.S. EPA/OAPQS/CORE CBI Office, Attention: WebFIRE Administrator, MD C404–02, 4930 Old Page Rd., Durham, NC 27703. At the discretion of the delegated authority, owners or operators shall also submit these RATAs to the delegated authority in the format specified by the delegated authority. Owners or operators shall submit calibration error testing, drift checks, and other information required in the performance evaluation as described in 40 CFR 63.2 and as required in this chapter. (40 CFR 63.10031(f)(1))

(b) For a PM CEMS, PM CPMS, or approved alternative monitoring using a HAP metals CEMS, within 60 days after the reporting periods ending on March 31st, June 30th, September 30th, and December 31st, the owner or operator shall submit quarterly reports to EPA's WebFIRE database by using the Compliance and Emissions Data Reporting Interface (CEDRI) that is accessed through EPA's Central Data Exchange (CDX) (www.epa.gov/cdx). The owner or operator shall use the appropriate electronic reporting form in CEDRI or provide an alternate electronic file consistent with EPA's reporting form output format. For each reporting period, the quarterly reports must include all of the calculated 30–boiler operating day rolling average values derived from the CEMS and PM CPMS. (40 CFR 63.10031(f)(2))

(c) Reports for an SO_2 CEMS, a Hg CEMS or sorbent trap monitoring system, an HCl or HF CEMS, and any supporting monitors for such systems (such as a diluent or moisture monitor) shall be submitted using the ECMPS Client Tool, as provided for in Appendices A and B to 40 CFR 63, Subpart UUUUU and 40 CFR 63.10021(f). (40 CFR 63.10031(f)(3))

(d) Submit the compliance reports required under paragraphs (c) and (d) of this section and the notification of compliance status required under 40 CFR 63.10030(e) to EPA's WebFIRE database by using the Compliance and Emissions Data Reporting Interface (CEDRI) that is accessed through EPA's Central Data Exchange (CDX) (www.epa.gov/cdx). The owner or operator shall use the appropriate electronic reporting form in CEDRI or provide an alternate electronic file consistent with EPA's reporting form output format. (40 CFR 63.10031(f)(4))

(e) All reports required by 40 CFR 63, Subpart UUUUU not subject to the requirements in paragraphs (f)(1) through (4) of this section must be sent to the Administrator at the appropriate address listed in 40 CFR 63.13. If acceptable to both the Administrator and the owner or operator of a source, these reports may be submitted on electronic media. The Administrator retains the right to require submittal of reports subject to paragraphs (f)(1), (2), and (3) of this section in paper format. (40 CFR 63.10031(f)(5))

7) If the owner or operator had a malfunction during the reporting period, the compliance report must include the number, duration, and a brief description for each type of malfunction which occurred during the reporting period and which caused or may have caused any applicable emission limitation to be exceeded. (40 CFR 63.10031(g))

Attachment B - Testing Requirements for New Control Devices for EGUs

Specific Conditions

PM/ SO_2/ H_2SO_4/ Hg

a. **Determination of monitoring parameters**

i. The owner or operator shall establish a site-specific minimum PAC injection rate operating limit during a performance test for mercury, according to the following requirements:[153]

1) The owner or operator shall collect activated carbon injection rate data every 15 minutes during the entire period of the performance tests.

2) Determine the hourly average activated carbon injection rate by computing the hourly averages using all of the 15-minute readings taken during each performance test.

3) Determine the lowest hourly average established during the performance test as your operating limit. When your unit operates at lower loads, multiply your activated carbon injection rate by the load fraction (e.g., actual heat input divided by heat input during performance test, for 50 percent load, multiply the injection rate operating limit by 0.5) to determine the required injection rate.

ii. The owner or operator shall determine the appropriate pressure drop range across the baghouse that will be used as the indicators of normal operation of the control devices.

1) The owner or operator shall monitor and record pressure drop across the baghouse at least once each per operating day. The owner or operator shall establish an appropriate pressure drop range for the normal operation of the baghouse after ninety (90) consecutive days of observation.

2) The owner or operator shall submit to the District the established appropriate ranges of the pressure drop for the baghouse. The report shall be submitted within 30 days following the end of the 90 day monitoring period.

[153] The requirements of establishing operating limit for PAC injection refer to Table 7 to 40 CFR 63, Subpart DDDDD.

b. **Tests for control efficiency** (Regulation 2.16, section 4.1.9.1)

i. The owner or operator shall perform tests with appropriate EPA Reference Method performance test within 180 days of achieving normal operation[154] on the inlet and outlet of the new control devices PJFF (for PM), FGD (for SO_2), Dry sorbent injection (for acid control), and PAC Injection (for Mercury) in order to determine their control efficiencies.

ii. The owner or operator shall conduct all performance tests in such a manner that the following testing requirements can be achieved.

1) The test shall be performed at 90% or higher of maximum capacity, or allowable/permitted capacity, or at a level of capacity which results in the greatest emissions that is representative of the operations. Failure to perform the test, at maximum capacity, allowable/permitted capacity, or at a level of capacity which resulted in the greatest emissions, may necessitate a re-test or necessitate a revision of the allowable/permitted capacity of the process equipment depending upon the difference between the testing results and the limit.

2) The owner or operator shall submit written test plans (protocol) for the control efficiency testing. They shall include the EPA test methods that will be used for performance evaluation testing, the process operating parameters that will be monitored during the performance test, and the control device performance indicators (e.g. pressure drop, minimum combustion chamber temperature) that will be monitored during the performance test. The test plans shall be furnished to the District at least 30 days prior to the actual date of the performance test.

3) The owner or operator shall provide the District at least 10 days prior notice of any performance test to afford the District the opportunity to have an observer present.

4) The owner or operator shall furnish the District with a written report of the results of the performance test within 60 days following the actual date of completion of the performance test.

5) The owner or operator shall provide written notification to the District of the actual date of initial startup. The written notification shall be postmarked within 15 days of achieving normal operation.

[154] Normal operation is defined as “after the shakedown period and when the unit is operating for the purpose of generating electricity.”

c. **Test methods required in 40 CFR 60, Subpart D** (use if applicable to U3, U4)

i. In conducting the performance tests required in 40 CFR 60.8, and subsequent performance tests as requested by the EPA Administrator, the owner or operator shall use as reference methods and procedures the test methods in appendix A of this part or other methods and procedures as specified in 40 CFR 60.46, except as provided in 40 CFR 60.8(b). Acceptable alternative methods and procedures are given in paragraph (d) of 40 CFR 60.46. (40 CFR 60.46(a))

ii. The owner or operator shall determine compliance with the PM and SO_2 standards in 40 CFR 60.42, 60.43, and 60.44 as follows: (40 CFR 60.46(b))

1) The emission rate (E) of PM and SO_2 shall be computed for each run using the following equation: (40 CFR 60.46(b)(1))

$$E = CF_d \frac{20.9}{20.9 - \%O_2}$$

Where:
E = Emission rate of pollutant, ng/J (1b/million Btu);
C = Concentration of pollutant, ng/dscm (1b/dscf);
$\%O_2$ = O_2 concentration, percent dry basis; and
F_d= Factor as determined from Method 19 of appendix A of this part.

2) Method 5 of appendix A of this part shall be used to determine the PM concentration (C) at affected facilities without wet flue-gas-desulfurization (FGD) systems and Method 5B of appendix A of this part shall be used to determine the PM concentration (C) after FGD systems. (40 CFR 60.46(b)(2))

(a) The sampling time and sample volume for each run shall be at least 60 minutes and 0.85 dscm (30 dscf). The probe and filter holder heating systems in the sampling train shall be set to provide an average gas temperature of 160 ± 14 ° C (320 ± 25 ° F). (40 CFR 60.46(b)(2)(i))

(b) The emission rate correction factor, integrated or grab sampling and analysis procedure of Method 3B of appendix A of this part shall be used to determine the O_2 concentration ($\%O_2$). The O_2 sample shall be obtained simultaneously with, and at the same traverse points as, the particulate sample. If the grab sampling procedure is used, the O_2 concentration for the run shall be the arithmetic mean of the sample O_2 concentrations at all traverse points. (40 CFR 60.46(b)(2)(ii))

(c) If the particulate run has more than 12 traverse points, the O_2 traverse points may be reduced to 12 provided that Method 1 of appendix A of this part is used to locate the 12 O_2 traverse points. (40 CFR 60.46(b)(2)(iii))

3) Method 9 of appendix A of this part and the procedures in 40 CFR 60.11 shall be used to determine opacity. (40 CFR 60.46(b)(3))

4) Method 6 of appendix A of this part shall be used to determine the SO_2 concentration. (40 CFR 60.46(b)(4))

(a) The sampling site shall be the same as that selected for the particulate sample. The sampling location in the duct shall be at the centroid of the cross section or at a point no closer to the walls than 1 m (3.28 ft). The sampling time and sample volume for each sample run shall be at least 20 minutes and 0.020 dscm (0.71 dscf). Two samples shall be taken during a 1-hour period, with each sample taken within a 30-minute interval. (40 CFR 60.46(b)(4)(i))

(b) The emission rate correction factor, integrated sampling and analysis procedure of Method 3B of appendix A of this part shall be used to determine the O_2 concentration (%O_2). The O_2 sample shall be taken simultaneously with, and at the same point as, the SO_2 sample. The SO_2 emission rate shall be computed for each pair of SO_2 and O_2 samples. The SO_2 emission rate (E) for each run shall be the arithmetic mean of the results of the two pairs of samples. (40 CFR 60.46(b)(4)(ii))

5) Method 7 of appendix A of this part shall be used to determine the NO_X concentration. (40 CFR 60.46(b)(5))

(a) The sampling site and location shall be the same as for the SO_2 sample. Each run shall consist of four grab samples, with each sample taken at about 15-minute intervals. (40 CFR 60.46(b)(5)(i))

(b) For each NO_x sample, the emission rate correction factor, grab sampling and analysis procedure of Method 3B of appendix A of this part shall be used to determine the O_2 concentration (%O_2). The sample shall be taken simultaneously with, and at the same point as, the NO_x sample. (40 CFR 60.46(b)(5)(ii))

(c) The NO_x emission rate shall be computed for each pair of NO_x and O_2 samples. The NO_x emission rate (E) for each run shall be the arithmetic mean of the results of the four pairs of samples. (40 CFR 60.46(b)(5)(iii))

iii. The owner or operator may use the following as alternatives to the reference methods and procedures in 40 CFR 60.46 or in other sections as specified: (40 CFR 60.46(d))

1) The emission rate (E) of PM, SO_2 and NO_x may be determined by using the Fc factor, provided that the following procedure is used: (40 CFR 60.46(d)(1))

(a) The emission rate (E) shall be computed using the following equation: (40 CFR 60.46(d)(1)(i))

$$E = CF_c \frac{100}{\%CO_2}$$

Where:
E = Emission rate of pollutant, ng/J (lb/MMBtu);
C = Concentration of pollutant, ng/dscm (lb/dscf);
$\%CO_2$= CO_2 concentration, percent dry basis; and
F_c= Factor as determined in appropriate sections of Method 19 of appendix A of this part.

(b) If and only if the average F_c factor in Method 19 of appendix A of this part is used to calculate E and either E is from 0.97 to 1.00 of the emission standard or the relative accuracy of a continuous emission monitoring system is from 17 to 20 percent, then three runs of Method 3B of appendix A of this part shall be used to determine the O_2 and CO_2 concentration according to the procedures in paragraph (b)(2)(ii), (4)(ii), or (5)(ii) of 40 CFR 60.46. Then if F_o(average of three runs), as calculated from the equation in Method 3B of appendix A of this part, is more than ± 3 percent than the average F_o value, as determined from the average values of F_d and F_c in Method 19 of appendix A of this part, *i.e.*, F_{oa}= 0.209 (F_{da}/F_{ca}), then the following procedure shall be followed: (40 CFR 60.46(d)(1)(ii))

(i) When F_o is less than 0.97 F_{oa}, then E shall be increased by that proportion under 0.97 F_{oa}, *e.g.*, if F_o is 0.95 F_{oa}, E shall be increased by 2 percent. This recalculated value shall be used to determine compliance with the emission standard. (40 CFR

60.46(d)(1)(ii)(A))

(ii) When F_o is less than 0.97 F_{oa} and when the average difference (d) between the continuous monitor minus the reference methods is negative, then E shall be increased by that proportion under 0.97 F_{oa}, *e.g.*, if F_o is 0.95 F_{oa}, E shall be increased by 2 percent. This recalculated value shall be used to determine compliance with the relative accuracy specification. (40 CFR 60.46(d)(1)(ii)(B))

(iii) When F_o is greater than 1.03 F_{oa} and when the average difference d is positive, then E shall be decreased by that proportion over 1.03 F_{oa}, *e.g.*, if F_o is 1.05 F_{oa}, E shall be decreased by 2 percent. This recalculated value shall be used to determine compliance with the relative accuracy specification. (40 CFR 60.46(d)(1)(ii)(C))

2) For Method 5 or 5B of appendix A–3 of this part, Method 17 of appendix A–6 of this part may be used at facilities with or without wet FGD systems if the stack gas temperature at the sampling location does not exceed an average temperature of 160 ° C (320 ° F). The procedures of sections 8.1 and 11.1 of Method 5B of appendix A–3 of this part may be used with Method 17 of appendix A–6 of this part only if it is used after wet FGD systems. Method 17 of appendix A–6 of this part shall not be used after wet FGD systems if the effluent gas is saturated or laden with water droplets. (40 CFR 60.46(d)(2))

3) Particulate matter and SO_2 may be determined simultaneously with the Method 5 of appendix A of this part train provided that the following changes are made: (40 CFR 60.46(d)(3))

(a) The filter and impinger apparatus in sections 2.1.5 and 2.1.6 of Method 8 of appendix A of this part is used in place of the condenser (section 2.1.7) of Method 5 of appendix A of this part. (40 CFR 60.46(d)(3)(i))

(b) All applicable procedures in Method 8 of appendix A of this part for the determination of SO_2(including moisture) are used. (40 CFR 60.46(d)(3)(ii))

4) For Method 6 of appendix A of this part, Method 6C of appendix A of this part may be used. Method 6A of appendix A of this part may also be used whenever Methods 6 and 3B of appendix A of this part

data are specified to determine the SO_2 emission rate, under the conditions in paragraph (d)(1) of 40 CFR 60.46. (40 CFR 60.46(d)(4))

5) For Method 7 of appendix A of this part, Method 7A, 7C, 7D, or 7E of appendix A of this part may be used. If Method 7C, 7D, or 7E of appendix A of this part is used, the sampling time for each run shall be at least 1 hour and the integrated sampling approach shall be used to determine the O_2 concentration (%O_2) for the emission rate correction factor. (40 CFR 60.46(d)(5))

6) For Method 3 of appendix A of this part, Method 3A or 3B of appendix A of this part may be used. (40 CFR 60.46(d)(6))

7) For Method 3B of appendix A of this part, Method 3A of appendix A of this part may be used. (40 CFR 60.46(d)(7))

Attachment C - Protocol Checklist for a Performance Test

A completed protocol should include the following information:

□ 1. Facility name, location, and ID #;
□ 2. Responsible Official and environmental contact names;
□ 3. Permit numbers that are requiring the test to be conducted;
□ 4. Test methods to be used (i.e. EPA Method 1, 2, 3, 4, and 5);
□ 5. Alternative test methods or description of modifications to the test methods to be used;
□ 6. Purpose of the test including equipment and pollutant to be tested; the purpose may be described in the permit that requires the test to be conducted or may be to show compliance with a federal regulation or emission standard;
□ 7. Tentative test dates (These may change but the District will need final notice at least 10 days in advance of the actual test dates in order to arrange for observation.);
□ 8. Maximum rated production capacity of the system;
□ 9. Production-rate goal planned during the performance test for demonstration of compliance (if appropriate, based on limits);
□ 10.Method to be used for determining rate of production during the performance test;
□ 11. Method to be used for determining rate of production during subsequent operations of the process equipment to demonstrate compliance;
□ 12. Description of normal operation cycles;
□ 13. Discussion of operating conditions that tend to cause worse case emissions; it is especially important to clarify this if worst case emissions do not come from the maximum production rate;
□ 14. Process flow diagram;
□ 15. The type and manufacturer of the control equipment, if any;
□ 16. The control equipment (baghouse, scrubber, condenser, etc.) parameter to be monitored and recorded during the performance test. Note that this data will be used to ensure representative operation during subsequent operations. These parameters can include pressure drops, flow rates, pH, and temperature. The values achieved during the test may be required during subsequent operations to describe what pressure drops, etcetera, are indicative of good operating performance; and
□ 17. How quality assurance and accuracy of the data will be maintained, including;
   - Sample identification and chain-of-custody procedures
   - If audit samples are required for this test method, audit sample provider and number of audit samples to be used

□ 18. Pipe, duct, stack, or flue diameter to be tested;
□ 19. Distances from the testing sample ports to the nearest upstream and downstream flow disturbances such as bends, valves, constrictions, expansions, and exit points for outlet and additionally for inlet;
□ 20. Determine number of traverse points to be tested for outlet and additionally for inlet if required using Appendix A-1 to 40 CFR Part 60;
   - Method 1 if stack diameter is >12"
   - Method 1a if stack diameter is greater than or equal to 4" and less than 12"
   - Alternate method of determination for <4"
   - If a sample location at least two stack or duct diameters downstream and half a diameter upstream from any flow disturbance is not available then an alternative procedure is available for determining the acceptability of a measurement location. This procedure described in Method 1, Section 11.5 allows for the determination of gas flow angles at the sampling points and comparison of the measured results with acceptability criteria.

□ 21. The Stack Test Review fee shall be submitted with each stack test protocol.

Attachment D - NO_x RACT Plan - Amendment 1

1. The oxides of nitrogen (NO_x, expressed as NO_2) emission from each utility boiler shall not exceed the rate as specified below, based upon a rolling 30-day average:

   Unit 1 0.47 lb/mmBtu of heat input
   Unit 2 0.47 lb/mmBtu of heat input
   Unit 3 0.52 lb/mmBtu of heat input
   Unit 4 0.52 lb/mmBtu of heat input

2. The NO_x emission rate for each utility boiler shall be determined using the methods and procedures specified in NO_x RACT Plan Appendix A - Amendment 1, except that any reference to an annual average shall be read as a rolling 30-day average.

3. The Louisville Gas and Electric Company Mill Creek Generating Station (LG&E/MCGS) shall install, maintain, and operate a NO_x continuous emissions monitoring system (CEMS) for each utility boiler and shall keep records and submit reports and other notifications as specified in NO_x RACT Plan Appendix A - Amendment 1.

4. The LG&E/MCGS shall keep a record identifying all deviations from the requirements of this NO_x RACT Plan and shall submit to the District a written report of all deviations that occurred during the preceding calendar quarter. The report shall contain the following information:
   A. The boiler number,
   B. The beginning and ending date of the reporting period,
   C. Identification of all periods during which a deviation occurred,
   D. A description, including the magnitude, of the deviation,
   E. If known, the cause of the deviation, and
   F. A description of all corrective actions taken to abate the deviation.

   If no deviation occurred during the calendar quarter, the report shall contain a negative declaration. Each report shall be submitted within 30 days following the end of the calendar quarter.

5. In lieu of the requirements in this NO_x RACT Plan, the LG&E/MCGS may comply with alternative requirements regarding emission limitations, equipment operation, test methods, monitoring, recordkeeping, or reporting, provided the following conditions are met:
   A. The alternative requirements are established and incorporated into an operating permit pursuant to a Title V Operating Permit issuance, renewal, or significant permit revision process as established in Regulation 2.16,
   B. The alternative requirements are consistent with the streamlining procedures and guidelines set forth in section II.A. of *White Paper Number 2 for Improved Implementation of the Part 70 Operating Permits Program*, March 5, 1996, U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards. The overall effect of compliance with alternative requirements shall consider the effect on an intrinsic basis, such as pounds per million Btu of heat input. However,

alternative requirements that are developed based upon revisions to the applicable requirements contained in 40 CFR Part 60 or Part 75 shall be approvable pursuant to this NO_x RACT Plan Element,

C. The U.S. Environmental Protection Agency (EPA) has not objected to the issuance, renewal, or revision of the Title V Operating Permit, and either

D. If the public comment period preceded the EPA review period, then the District had transmitted any public comments concerning the alternative requirements to EPA with the proposed permit, or

E. If the EPA and public comment periods ran concurrently, then the District had transmitted any public comments concerning the alternative requirements to EPA no later than 5 working days after the end of the public comment period.

The District's determination of approval of any alternative requirements is not binding on EPA. Noncompliance with any alternative requirement established pursuant to the Title V Operating Permit process constitutes a violation of this NO_x RACT Plan.

History: Approved 11-8-99; effective 1-1-00; amended a1/10-18-00 effective 1-1-01.

Appendix A to NO_x RACT Plan - Amendment 1
Requirements for NO_x CEMS

I. General Operating Requirements

A. Primary measurement requirements. The LG&E/MCGS shall, for each utility boiler, install, certify, operate, and maintain, in accordance with the requirements of 40 CFR 75, an oxides of nitrogen (NO_x) continuous emission monitoring system (CEMS), consisting of a NO_x pollutant concentration monitor and an oxygen (O_2) or carbon dioxide (CO_2) diluent gas monitor, with an automated data acquisition and handling system for measuring and recording NO_x concentration (in parts per million [ppm]), O_2 or CO_2 concentration (in percent O_2 or CO_2) and NO_x emission rate (in lb/mmBtu of heat input) discharged to the atmosphere. Any reference in this Appendix to an annual average shall be read as a rolling 30-day average. The LG&E/MCGS shall account for total NO_x emissions, both nitrogen oxide (NO) and nitrogen dioxide (NO_2), either by monitoring for both NO and NO_2 or by monitoring for NO only and adjusting the emissions data to account for NO_2.

B. Primary equipment performance requirements. The LG&E/MCGS shall ensure that each CEMS used to demonstrate compliance with the NO_x emission limit meets the equipment, installation, and performance specifications in 40 CFR 75 Appendix A, and is maintained according to the quality assurance and quality control procedures in 40 CFR 75 Appendix B. The NO_x emission rate for each utility boiler shall be recorded as lb/mmBtu of heat input.

C. Primary equipment hourly operating requirements.

1. The LG&E/MCGS shall ensure that all CEMS are in operation and monitoring the emissions from the associated utility boiler at all times that the utility boiler combusts any fuel except during a period of any of the following:
   a. Calibration, quality assurance, or preventive maintenance, any of which is performed pursuant to 40 CFR 75.21, 40 CFR 75 Appendix B, District regulations, District permit conditions, or this NO_x RACT Plan, or
   b. Repair, backups of data from the data acquisition and handling system, or recertification, any of which is performed pursuant to 40 CFR 75.20.
2. The LG&E/MCGS shall ensure that the following requirements are met:
   a. Each CEMS and component thereof is capable of completing a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute interval. The LG&E/MCGS shall reduce all volumetric flow, CO_2 concentration, O_2 concentration, NO_x concentration, and NO_x emission rate data collected by the monitors to hourly averages. Hourly averages shall be computed using at least one data point in each 15- minute quadrant of an hour during which the utility boiler combusted fuel during that quadrant of the hour. Notwithstanding this requirement, an hourly average may be computed from at least two data points separated by a minimum of 15 minutes (where the unit operates for more than one quadrant of the hour) if data are unavailable as a result of the performance of any activity specified in paragraph I.C.1. of this Appendix. The LG&E/MCGS shall use all valid measurements or data points collected during an hour to calculate the hourly averages. All data points collected during an hour shall be, to the extent practicable, evenly spaced over the hour.
   b. Failure of a CO_2 or O_2 diluent concentration monitor, flow monitor, or NO_X pollutant concentration monitor to acquire the minimum number of data points for calculation of an hourly average shall result in the failure to obtain a valid hour of data and the loss of such component data for the entire hour. An hourly average NO_x emission rate in lb/mmBtu of heat input is valid only if the minimum number of data points are acquired by both the pollutant concentration monitor (NO_x) and the diluent monitor (CO_2 or O_2). If a valid hour of data is not obtained, the owner or operator shall estimate and record emissions, moisture, or flow data for the missing hour by means of the automated data acquisition and handling system, in accordance with the applicable procedure for missing data substitution in 40 CFR 75 Subpart D .

D. **Optional backup monitor requirements.** If the LG&E/MCGS chooses to use two or more CEMS, each of which is capable of monitoring the same stack or duct at a specific utility boiler, then the LG&E/MCGS shall designate one CEMS as the primary monitoring system and shall record this designation in the monitoring plan. The LG&E/MCGS shall designate any other CEMS as a backup CEMS in the monitoring plan. Any other backup CEMS shall be designated as a redundant backup CEMS, non-redundant backup CEMS, or reference method CEMS, as described in 40 CFR 75.20(d). When the certified primary monitoring system is operating and not out-of-control as defined in 40 CFR 75.24, only data from the certified primary monitoring system shall be reported as valid, quality-assured data. Thus, data from a backup CEMS may be reported as valid, quality-assured data only when a backup CEMS is operating and not out-of-control as defined in 40 CFR 75.24 or in the applicable reference method in 40 CFR 60 Appendix A and when the certified primary monitoring system is not operating or is operating but out-of-control. A particular monitor may be designated both as a certified primary monitor for one unit and as a certified redundant backup monitor for another unit.

E. **Minimum measurement capability requirements.** Each CEMS and component thereof shall be capable of accurately measuring, recording, and reporting data, and shall not incur a full scale exceedance, except as provided in section 2.1.2.5 of 40 CFR 75 Appendix A.

F. The LG&E/MCGS shall not operate a utility boiler so as to discharge, or allow to be discharged, emissions of NO_x to the atmosphere without accounting for all such emissions in accordance with the methods and procedures specified in this Appendix.

G. The LG&E/MCGS shall not disrupt the CEMS, any portion thereof, or any other approved emission monitoring method, and thereby avoid monitoring and recording NO_x emissions discharged into the atmosphere, except for periods of recertification or periods when calibration, quality assurance testing, or maintenance is performed in accordance with the provisions of this Appendix.

H. The LG&E/MCGS shall not retire or permanently discontinue use of the CEMS, any component thereof, or any other approved emission monitoring system under this Appendix except under any one of the following circumstances:

1. The LG&E/MCGS is monitoring NO_x emissions from the utility boiler with another certified monitoring system approved in accordance with the provisions of paragraph I.D. of this Appendix, or
2. The LG&E/MCGS submits notification of the date of certification testing of a replacement monitoring system.

I. The quality assurance and quality control requirements in 40 CFR 75.21 that apply to NO_x pollutant concentration monitors and diluent gas monitors shall be met. A NO_x pollutant concentration monitor for determining NO_x emissions shall meet the same certification testing requirements, quality assurance requirements, and bias test requirements as those specified in 40 CFR 75 for an SO_2 pollutant concentration monitor.

J. **Moisture correction.** If a correction for the stack gas moisture content is needed to properly calculate the NO_x emission rate in lb/mmBtu of heat input (i.e., if the NO_x pollutant concentration monitor measures on a different moisture basis from the diluent monitor), LG&E/MCGS shall either report a fuel-specific default moisture value for each utility boiler operating hour, as provided in 40 CFR 75.11(b)(1), or shall install, operate, maintain, and quality assure a continuous moisture monitoring system, as defined in 40 CFR 75.11(b)(2). Notwithstanding this requirement, if Equation 19-3, 19-4 or 19-8 in Method 19 in Appendix A to 40 CFR Part 60 is used to measure NO_x emission rate, the following fuel-specific default moisture percentages shall be used in lieu of the default values specified in 40 CFR 75.11(b)(1): 5.0%, for anthracite coal; 8.0% for bituminous coal; 12.0% for sub-bituminous coal; 13.0% for lignite coal; and 15.0% for wood.

II. Specific Provisions for Monitoring NO_x Emission Rate (NO_x and diluent gas monitors)

A. The LG&E/MCGS shall meet the general operating requirements in 40 CFR 75.10 for a NO_x CEMS for each utility boiler. The diluent gas monitor in the NO_x CEMS may measure either O_2 or CO_2 concentration in the flue gases.

B. The LG&E/MCGS shall calculate hourly and rolling 30-day NO_x emission rates (in lb/mmBtu of heat input) by combining the NO_x concentration (in ppm), diluent concentration (in percent O_2 or CO_2), and percent moisture (if applicable) measurements according to the procedures in 40 CFR 75 Appendix F.

III. Monitoring plan

The LG&E/MCGS shall prepare and maintain a monitoring plan as specified in 40 CFR 75.53. The monitoring plan shall be submitted to the District no later than 45 days prior to the first scheduled certification test.

IV. Recordkeeping Provisions

A. The LG&E/MCGS shall maintain for each utility boiler a file of all measurements, data, reports, and other information required by this Appendix at the stationary source in a form suitable for inspection for at least 5 years from the date of each record. This file shall contain the following information:

1. The data and information required in paragraph IV.B. of this Appendix,
2. The component data and information used to calculate values required in paragraph IV.B. of this Appendix,
3. The current monitoring plan as specified in 40 CFR 75.53, and
4. The quality control plan as described in 40 CFR 75 Appendix B.

B. **NO_x emission record provisions.** The LG&E/MCGS shall record hourly the following information as measured and reported from the certified primary monitor, certified back-up or certified portable monitor, or other approved method of emissions determination for each utility boiler:

1. Date and hour,
2. Hourly average NO_x concentration (ppm, rounded to the nearest tenth),
3. Hourly average diluent gas concentration (percent O_2 or percent CO_2, rounded to the nearest tenth),
4. Hourly average NO_x emission rate (lb/mmBtu of heat input, rounded to nearest hundredth),
5. Hourly average NO_x emission rate (lb/mmBtu of heat input, rounded to nearest hundredth) adjusted for bias, if a bias adjustment factor is required by 40 CFR 75.24 (d),
6. Percent monitoring system data availability (recorded to the nearest tenth of a percent), calculated pursuant to 40 CFR 75.32,
7. Method of determination for hourly average NO_x emission rate using Codes 1-55 in 40 CFR 75.57 Table 4A, and
8. Unique code identifying emissions formula used to derive hourly average NO_x emission rate, as provided for in 40 CFR 75.53.

V. Certification, Quality Assurance, and Quality Control Record Provisions

A. For each NO_x pollutant concentration monitor and diluent gas monitor, the LG&E/MCGS shall record the following:

1. Results of all trial runs and certification tests and quality assurance activities and measurements (including all reference method field test sheets, charts, records of combined system responses, laboratory analyses, and example calculations) necessary to substantiate compliance with all relevant requirements of this Appendix,
2. Bias test results as specified in 40 CFR 75, Appendix A, section 7.6.4,
3. The appropriate bias adjustment factor as follows:
   a. The value derived from Equations A-11 and A-12 in 40 CFR 75 Appendix A for any monitoring system or component that failed the bias test, or
   b. A value of 1.0 for any monitoring system or component that passed the bias test, and
4. The component/system identification code.

B. For each NO_x pollutant concentration monitor and diluent gas monitor, the LG&E/MCGS shall record the following for all daily and 7-day calibration error tests, including any follow-up tests after corrective action:

1. Instrument span and span scale,
2. Date and hour,
3. Reference value (i.e., calibration gas concentration or reference signal value, in ppm or other appropriate units),
4. Observed value (monitor response during calibration, in ppm or other appropriate units), (flag if using alternative performance specification for low emitters or differential pressure monitors),

5. Percent calibration error (rounded to the nearest tenth of a percent),
6. Calibration gas level,
7. Test number and reason for test,
8. For 7-day calibrations tests for certification or recertification, a certification from the cylinder gas vendor or CEMS vendor that calibration gases as defined in 40 CFR 72.2 and 40 CFR 75 Appendix A were used to conduct calibration error testing,
9. Description of any adjustments, corrective actions, or maintenance following a test,
10. For quality test for off-line calibration, whether the unit is off-line or on-line, and
11. The component/system identification code.

C. For each NO_x pollutant concentration monitor and diluent gas monitor, the LG&E/MCGS shall record the following for the initial and all subsequent linearity checks, including any follow-up tests after corrective action:

1. Instrument span and span scale,
2. Calibration gas level,
3. Date, hour, and minute of each gas injection at each calibration gas level,
4. Reference value (i.e., reference gas concentration for each gas injection at each calibration gas level, in ppm or other appropriate units),
5. Observed value (monitor response to each reference gas injection at each calibration gas level, in ppm or other appropriate units),
6. Mean of reference values and mean of measured values at each calibration gas level
7. Linearity error at each of the reference gases concentrations (rounded to the nearest tenth of a percent), (flag if using alternative performance specification),
8. Test number and reason for test (flag if aborted test),
9. Description of any adjustments, corrective action, or maintenance prior to a passed test or following a failed test,
10. The number of out-of-control hours, if any, following any tests, and
11. The component/system identification code.

D. For each NO_x pollutant concentration monitor and diluent gas monitor, the LG&E/MCGS shall record the following information for the initial and all subsequent relative accuracy tests and test audits:

1. Reference method(s) used,
2. Individual test run data from the relative accuracy test audit for the NO_x pollutant concentration monitor or diluent gas monitor, including:
    a. Date, hour, and minute of beginning of test run,
    b. Date, hour, and minute of end of test run,
    c. Monitoring system identification code,
    d. Test number and reason for test,
    e. Operating load level (low, mid, high, or normal, as appropriate) and number of load levels comprising test,

f. Normal load indicator for flow RATAs (except for peaking units),
g. Units of measure,
h. Run number,
i. Run data from CEMS being tested, in the appropriate units of measure,
j. Run data for reference method, in the appropriate units of measure,
k. Flag value (0, 1, or 9, as appropriate) indicating whether run has been used in calculating relative accuracy and bias values or whether the test was aborted prior to completion,
l. Average gross unit load (expressed as a total gross unit load rounded to the nearest MWe or as steam load rounded to the nearest thousand lb/hr), and
m. Flag to indicate whether an alternative performance specification has been used,

3. Calculations and tabulated results, as follows:
   a. Arithmetic mean of the monitoring system measurement values, reference method values, and of their differences, as specified in Equation A-7 in 40 CFR 75 Appendix A,
   b. Standard deviation, as specified in Equation A-8 in 40 CFR 75 Appendix A,
   c. Confidence coefficient, as specified in Equation A-9 in 40 CFR 75 Appendix A,
   d. Statistical "t" value used in calculations,
   e. Relative accuracy test results, as specified in Equation A-10 in 40 CFR 75 Appendix A,
   f. Bias test results as specified in section 7.6.4 in 40 CFR 75 Appendix A,
   g. Bias adjustment factor from Equation A-12 in 40 CFR 75 Appendix A for any monitoring system or component that failed the bias test (except as otherwise provided in section 7.6.5 in 40 CFR 75 Appendix A) and 1.000 for any monitoring system or component that passed the bias test,
   h. F-factor value(s) used to convert NO_x pollutant concentration and diluent gas (O_2 or CO_2) concentration measurements into NO_x emission rates (in lb/mmBtu),
   i. The raw data and calculated results for any stratification tests performed in accordance with sections 6.5.6.1 through 6.5.6.3 in 40 CFR 75 Appendix A, and
   j. For moisture monitoring systems, the coefficient "K" factor or other mathematical algorithm used to adjust the monitoring system with respect to the reference method,
4. Description of any adjustment, corrective action, or maintenance prior to a passed test or following a failed or aborted test,
5. For each run of each test using Method 7E or 3A in Appendix A of 40 CFR 60 to determine NO_x, CO_2, or O_2 concentration the following:
   a. Pollutant or diluent gas being measured,

b. Span of reference method analyzer,
c. Type of reference method system (e.g., extractive or dilution type),
d. Reference method dilution factor (dilution type systems, only),
e. Reference gas concentration (low, mid, and high gas levels) used for the 3-point, pre-test analyzer calibration error test (or, for dilution type reference method systems, for the 3-point, pre-test system calibration error test) and for any subsequent recalibrations,
f. Analyzer responses to the zero-, mid-, and high-level calibration gases during the 3-point pre-test analyzer (or system) calibration error test and during any subsequent recalibration(s),
g. Analyzer calibration error at each gas level (zero, mid, and high) for the 3-point, pre-test analyzer (or system) calibration error test and for any subsequent recalibration(s) (percent of span value),
h. Upscale gas concentration (mid or high gas level) used for each pre-run or post-run system bias check or, for dilution type reference method systems, for each pre-run or post-run system calibration error check,
i. Analyzer response to the calibration gas for each pre-run or post-run system bias (or system calibration error) check,
j. The arithmetic average of the analyzer responses to the zero-level gas, for each pair of pre- and post-run system bias (or system calibration error) checks,
k. The arithmetic average of the analyzer responses to the upscale calibration gas, for each pair of pre- and post-run system bias (or system calibration error) checks,
l. The results of each pre-run and each post-run system bias (or system calibration error) check using the zero-level gas (percentage of span value),
m. The results of each pre-run and each post-run system bias (or system calibration error) check using the upscale calibration gas (percentage of span value),
n. Calibration drift and zero drift of analyzer during each RATA run (percentage of span value),
o. Moisture basis of the reference method analysis,
p. Moisture content of stack gas, in percent, during each test run (if needed to convert to moisture basis of CEMS being tested),
q. Unadjusted (raw) average pollutant or diluent gas concentration for each run,
r. Average pollutant or diluent gas concentration for each run, corrected for calibration bias (or calibration error) and, if applicable, corrected for moisture,
s. The F-factor used to convert reference method data to units of lb/mmBtu (if applicable)
t. Date(s) of the latest analyzer interference test(s),
u. Results of the latest analyzer interference test(s),
v. Date of the latest NO_2 to NO conversion test (Method 7E only),

w. Results of the latest NO_2 to NO conversion test (Method 7E only), and

x. For each calibration gas cylinder used during each RATA, record the cylinder gas vendor, cylinder number, expiration date, pollutant(s) in the cylinder, and

6. The number of out-of-control hours, if any, following any tests, and
7. The component/system identification code.

VI. Notifications

A. The LG&E/MCGS or a designated representative shall submit notice to the District for the following purposes, as required by this Appendix:

1. Initial certification and recertification test notifications. Written notification shall be submitted of initial certification tests, recertification tests, and revised test dates as specified in 40 CFR 75.20 for continuous emission monitoring systems, except for testing only of the data acquisition and handling system, and
2. Notification of initial certification testing. Initial certification test notifications shall be submitted not later than 45 days prior to the first scheduled day of initial certification testing. Testing may be performed on a date other than that already provided in a notice under this subparagraph as long as notice of the new date is provided either in writing or by telephone or other means at least 7 days prior to the original scheduled test date or the revised test date, whichever is earlier.

B. For retesting following a loss of certification under 40 CFR 75.20(a)(5) or for recertification under 40 CFR 75.20(b), notice of testing shall be submitted either in writing or by telephone at least 7 days prior to the first scheduled day of testing, except that in emergency situations when testing is required following an uncontrollable failure of equipment that results in lost data, notice shall be sufficient if provided within 2 business days following the date when testing is scheduled. Testing may be performed on a date other than that already provided in a notice under this subparagraph as long as notice of the new date is provided by telephone or other means at least 2 business days prior to the original scheduled test date or the revised test date, whichever is earlier.

C. Notwithstanding the notice requirements of paragraph B. above, the LG&E/MCGS may elect to repeat a certification test immediately, without advance notification, whenever the LG&E/MCGS has determined during the certification testing that a test was failed or that a second test is necessary in order to attain a reduced relative accuracy test frequency.

D. Written notice shall be submitted, either by mail or facsimile, of the date of periodic relative accuracy testing performed under 40 CFR Part 75 Appendix B no later than 21 days prior to the first scheduled day of testing. Testing may be performed on a date other than that already provided in a notice under this subparagraph as long as notice of the new date is provided either in writing or by telephone or other means acceptable to the District, and the notice is provided as soon as practicable after the new testing date is known, but no later than 24 hours in advance of the new date of testing.

E. Notwithstanding the notice requirements under paragraph D. above, the LG&E/MCGS may elect to repeat a periodic relative accuracy test immediately, without additional notification whenever the LG&E/MCGS has determined that a test was failed, or that a second test is necessary in order to attain a reduced relative accuracy test frequency. If an observer from the District is present when a test is rescheduled, the observer may waive all notification requirements under paragraph D. above for the rescheduled test.

VII. Quarterly reports

A. The LG&E/MCGS shall, within 30 days following the end of each calendar quarter, submit a report to the District that includes the following data and information for each utility boiler:

1. The information and hourly data required in this Appendix, including all emissions and quality assurance data, and
2. Average NO_x emission rate (lb/mmBtu of heat input, rounded to the nearest hundredth) during the rolling 30-day averaging periods.

B. The LG&E/MCGS shall submit a certification in support of each quarterly emissions monitoring report. This certification shall indicate whether the monitoring data submitted were recorded in accordance with the requirements of this Appendix. In the event of any missing data periods, this certification shall include a description of the measures taken to minimize or eliminate the causes for the missing data periods.

Attachment E - 40 CFR 75, Subpart G

The owner or operator shall comply with the following requirements unless there are more current promulgated regulations:

Specific Conditions

S1. **Reporting Requirements for Continuous Emission Monitoring**

a. **General provisions** (40 CFR 75.60)

i. If requested in writing (or by electronic mail) by the applicable EPA Regional Office, appropriate State, and/or appropriate local air pollution control agency, the designated representative shall submit a hardcopy RATA report within 45 days after completing a required semiannual or annual RATA according to section 2.3.1 of appendix B to this part (for standard RATA frequencies and reduced RATA frequencies), or within 15 days of receiving the request, whichever is later. The designated representative shall report the hardcopy information required by 40 CFR 75.59(a)(9), as specified in Condition S1.a..ii., to the applicable EPA Regional Office, appropriate State, and/or appropriate local air pollution control agency that requested the RATA report. (40 CFR 75.60(b)(6))

ii. When hardcopy relative accuracy test reports, certification reports, recertification reports, or semiannual or annual reports for gas or flow rate CEMS, the reports shall include, at a minimum, the following elements (as applicable to the type(s) of test(s) performed): (40 CFR 75.59(a)(9))

1) Summarized test results. (40 CFR 75.59(a)(9)(i))

2) DAHS printouts of the CEMS data generated during the calibration error, linearity, cycle time, and relative accuracy tests. (40 CFR 75.59(a)(9)(ii))

3) For pollutant concentration monitor or diluent monitor relative accuracy tests at normal operating load: (40 CFR 75.59(a)(9)(iii))

(a) The raw reference method data from each run, i.e., the data under paragraph (a)(7)(iv)(Q) of 40 CFR 75.59 (usually in the form of a computerized printout, showing a series of one-minute readings and the run average); (40 CFR 75.59(a)(9)(iii)(A))

(b) The raw data and results for all required pre-test, post-test, pre-run and post-run quality assurance checks (*i.e.*, calibration gas injections) of the reference method analyzers, i.e., the data under paragraphs (a)(7)(iv)(E) through (a)(7)(iv)(N) of 40 CFR 75.59 (supporting information for RATA using Method 6C, 7E, or 3A); (40 CFR 75.59(a)(9)(iii)(B))

(c) The raw data and results for any moisture measurements made during the relative accuracy testing, i.e., the data under paragraphs (a)(7)(v)(A) through (a)(7)(v)(O) of 40 CFR 75.59 (supporting information for RATA using Method 4); and (40 CFR 75.59(a)(9)(iii)(C))

(d) Tabulated, final, corrected reference method run data (*i.e.*, the actual values used in the relative accuracy calculations), along with the equations used to convert the raw data to the final values and example calculations to demonstrate how the test data were reduced. (40 CFR 75.59(a)(9)(iii)(D))

4) For relative accuracy tests for flow monitors: (40 CFR 75.59(a)(9)(iv))

(a) The raw flow rate reference method data, from Reference Method 2 (or its allowable alternatives) under appendix A to part 60 of this chapter, including auxiliary moisture data (often in the form of handwritten data sheets), i.e., the data under paragraphs (a)(7)(ii)(A) through (a)(7)(ii)(T), paragraphs (a)(7)(iii)(A) through (a)(7)(iii)(M), and, if applicable, paragraphs (a)(7)(v)(A) through (a)(7)(v)(O) of 40 CFR 75.59 (supporting information for RATA using Method 2 and Method 4) ; and (40 CFR 75.59(a)(9)(iv)(A))

(b) The tabulated, final volumetric flow rate values used in the relative accuracy calculations (determined from the flow rate reference method data and other necessary measurements, such as moisture, stack temperature and pressure), along with the equations used to convert the raw data to the final values and example calculations to demonstrate how the test data were reduced. (40 CFR 75.59(a)(9)(iv)(B))

5) Calibration gas certificates for the gases used in the linearity, calibration error, and cycle time tests and for the calibration gases used to quality assure the gas monitor reference method data during the relative accuracy test audit. (40 CFR 75.59(a)(9)(v))

6) Laboratory calibrations of the source sampling equipment. (40 CFR 75.59(a)(9)(vi))

7) A copy of the test protocol used for the CEMS certifications or recertifications, including narrative that explains any testing abnormalities, problematic sampling, and analytical conditions that required a change to the test protocol, and/or solutions to technical problems encountered during the testing program. (40 CFR 75.59(a)(9)(vii))

8) Diagrams illustrating test locations and sample point locations (to verify that locations are consistent with information in the monitoring plan). Include a discussion of any special traversing or measurement scheme. The discussion shall also confirm that sample points satisfy applicable acceptance criteria. (40 CFR 75.59(a)(9)(viii))

9) Names of key personnel involved in the test program, including test team members, plant contacts, agency representatives and test observers on site. (40 CFR 75.59(a)(9)(vix))

10) For testing involving use of EPA Protocol gases, the owner or operator shall record in electronic and hardcopy format the following information, as applicable: (40 CFR 75.59(a)(9)(x))

(a) On and after September 26, 2011, for each gas monitor, for both low and high measurement ranges, record the following information for the mid-level or high-level EPA Protocol gas (as applicable) that is used for daily calibration error tests, and the low-, mid-, and high-level gases used for quarterly linearity checks. For O_2 , if purified air is used as the high-level gas for daily calibrations or linearity checks, record the following information for the low- and mid-level EPA Protocol gas used for linearity checks, instead: (40 CFR 75.59(a)(9)(x)(A))

(i) Gas level code; (40 CFR 75.59(a)(9)(x)(A)(1))
(ii) A code for the type of EPA Protocol gas used; (40 CFR 75.59(a)(9)(x)(A)(2))
(iii) The PGVP vendor ID issued by EPA for the EPA Protocol gas production site that supplied the EPA Protocol gas cylinder; (40 CFR 75.59(a)(9)(x)(A)(3))
(iv) The expiration date for the EPA Protocol gas cylinder; and (40 CFR 75.59(a)(9)(x)(A)(4))
(v) The cylinder number. (40 CFR 75.59(a)(9)(x)(A)(5))

(b) On and after September 26, 2011, for each usage of Reference Method 3A in appendix A-2 to part 60 of this chapter, or Method 6C or 7E in appendix A-4 to part 60 of this chapter performed using EPA Protocol gas for the certification, recertification, routine quality assurance or diagnostic testing (reportable diagnostics, only) of a Part 75 monitoring system, record the information required by paragraphs (a)(9)(x)(A)(*1*) through (*5*) of 40 CFR 75.59. See Condition S1.a.ii.(10)(a){(i) through (v). (40 CFR 75.59(a)(9)(x)(B))

11) On and after March 27, 2012, for all RATAs performed pursuant to 40 CFR 75.74(c)(2)(ii), section 6.5 of appendix A to this part and section 2.3.1 of appendix B to this part, and for all NO_X emission testing performed pursuant to section 2.1 of appendix E to this part, or 40 CFR 75.19(c)(1)(iv), the owner or operator shall record the following information as provided by the AETB: (40 CFR 75.59(a)(9)(xi))

(a) The name, telephone number and e-mail address of the Air Emission Testing Body; (40 CFR 75.59(a)(9)(xi)(A))

(b) The name of each on-site Qualified Individual, as defined in 40 CFR 72.2 of this chapter; (40 CFR 75.59(a)(9)(xi)(B))

(c) For the reference method(s) that were performed, the date(s) that each on-site Qualified Individual took and passed the relevant qualification exam(s) required by ASTM D7036-04 (incorporated by reference, *see* 40 CFR 75.6); and (40 CFR 75.59(a)(9)(xi)(C))

(d) The name and e-mail address of each qualification exam provider. (40 CFR 75.59(a)(9)(xi)(D))

b. **Notifications** (40 CFR 75.61)

i. *Initial certification and recertification test notifications*. The owner or operator or designated representative for an affected unit shall submit written notification of initial certification tests and revised test dates as specified in 75.20 (Initial certification and recertification procedures) for continuous emission monitoring systems, for alternative monitoring systems under subpart E of this part, or for excepted monitoring systems under appendix E to this part, except as provided in paragraphs (a)(1)(iii) and (a)(1)(iv) of 40 CFR 75.61. (40 CFR75.61(a)(1))

1) Notification of initial certification testing and full recertification. Initial certification test notifications and notifications of full recertification testing under 40 CFR 75.20(b)(2) shall be submitted

not later than 21 days prior to the first scheduled day of certification or recertification testing. In emergency situations when full recertification testing is required following an uncontrollable failure of equipment that results in lost data, notice shall be sufficient if provided within 2 business days following the date when testing is scheduled. Testing may be performed on a date other than that already provided in a notice under this subparagraph as long as notice of the new date is provided either in writing or by telephone or other means at least 7 days prior to the original scheduled test date or the revised test date, whichever is earlier. (40 CFR75.61(a)(1)(i))

2) Notification of certification retesting, and partial recertification testing. For retesting required following a loss of certification under 40 CFR 75.20(a)(5) or for partial recertification testing required under 40 CFR 75.20(b)(2), notice of the date of any required RATA testing or any required retesting under section 2.3 in appendix E to this part shall be submitted either in writing or by telephone at least 7 days prior to the first scheduled day of testing; except that in emergency situations when testing is required following an uncontrollable failure of equipment that results in lost data, notice shall be sufficient if provided within 2 business days following the date when testing is scheduled. Testing may be performed on a date other than that already provided in a notice under this subparagraph as long as notice of the new date is provided by telephone or other means at least 2 business days prior to the original scheduled test date or the revised test date, whichever is earlier. (40 CFR75.61(a)(1)(ii))

3) Repeat of testing without notice. Notwithstanding the above notice requirements, the owner or operator may elect to repeat a certification or recertification test immediately, without advance notification, whenever the owner or operator has determined during the certification or recertification testing that a test was failed or must be aborted, or that a second test is necessary in order to attain a reduced relative accuracy test frequency. (40 CFR75.61(a)(1)(iii))

ii. *New unit, newly affected unit, new stack, or new flue gas desulfurization system operation notification*. The designated representative for an affected unit shall submit written notification: For a new unit or a newly affected unit, of the planned date when a new unit or newly affected unit will commence commercial operation, or becomes affected, or, for new stack or flue gas desulfurization system, of the planned date when a new stack or flue gas desulfurization system will be completed and emissions will first exit to the atmosphere. (40 CFR75.61(a)(2))

1) Notification of the planned date shall be submitted not later than 45 days prior to the date the unit commences commercial operation or becomes affected, or not later than 45 days prior to the date when a new stack or flue gas desulfurization system exhausts emissions to the atmosphere. (40 CFR75.61(a)(2)(i))

2) If the date when the unit commences commercial operation or becomes affected, or the date when the new stack or flue gas desulfurization system exhausts emissions to the atmosphere, whichever is applicable, changes from the planned date, a notification of the actual date shall be submitted not later than 7 days following: The date the unit commences commercial operation or becomes affected, or the date when a new stack or flue gas desulfurization system exhausts emissions to the atmosphere. (40 CFR75.61(a)(2)(ii))

iii. *Unit shutdown and recommencement of commercial operation*. For an affected unit that will be shut down on the relevant compliance date specified in 40 CFR 75.4 or in a State or Federal pollutant mass emissions reduction program that adopts the monitoring and reporting requirements of this part, if the owner or operator is relying on the provisions in 40 CFR 75.4(d) to postpone certification testing, the designated representative for the unit shall submit notification of unit shutdown and recommencement of commercial operation as follows: (40 CFR75.61(a)(3))

1) For planned unit shutdowns (e.g., extended maintenance outages), written notification of the planned shutdown date shall be provided at least 21 days prior to the applicable compliance date, and written notification of the planned date of recommencement of commercial operation shall be provided at least 21 days in advance of unit restart. If the actual shutdown date or the actual date of recommencement of commercial operation differs from the planned date, written notice of the actual date shall be submitted no later than 7 days following the actual date of shutdown or of recommencement of commercial operation, as applicable; (40 CFR75.61(a)(3)(i))

2) For unplanned unit shutdowns (e.g., forced outages), written notification of the actual shutdown date shall be provided no more than 7 days after the shutdown, and written notification of the planned date of recommencement of commercial operation shall be provided at least 21 days in advance of unit restart. If the actual date of recommencement of commercial operation differs from the expected date, written notice of the actual date shall be submitted no later than 7 days following the actual date of recommencement of commercial operation. (40 CFR75.61(a)(3)(ii))

iv. *Periodic relative accuracy test audits*. The owner or operator or designated representative of an affected unit shall submit written notice of the date of periodic relative accuracy testing performed under section 2.3.1 of appendix B to this part, no later than 21 days prior to the first scheduled day of testing. Testing may be performed on a date other than that already provided in a notice under this subparagraph as long as notice of the new date is provided either in writing or by telephone or other means acceptable to the respective State agency or office of EPA, and the notice is provided as soon as practicable after the new testing date is known, but no later than twenty-four (24) hours in advance of the new date of testing. (40 CFR75.61(a)(5))

1) Written notification under paragraph (a) (5) of 40 CFR 75.61 may be provided either by mail or by facsimile. In addition, written notification may be provided by electronic mail, provided that the respective State agency or office of EPA agrees that this is an acceptable form of notification. (40 CFR75.61(a)(5)(i))

2) Notwithstanding the notice requirements under paragraph (a)(5) of 40 CFR 75.61, the owner or operator may elect to repeat a periodic relative accuracy test, appendix E restest, or low mass emissions unit retest immediately, without additional notification whenever the owner or operator has determined that a test was failed, or that a second test is necessary in order to attain a reduced relative accuracy test frequency. (40 CFR75.61(a)(5)(ii))

v. *Certification deadline date for new or newly affected units*. The designated representative of a new or newly affected unit shall provide notification of the date on which the relevant deadline for initial certification is reached, either as provided in 75.4(b) or 75.4(c), or as specified in a State or Federal SO_2 or NO_X mass emission reduction program that incorporates by reference, or otherwise adopts, the monitoring, recordkeeping, and reporting requirements of subpart F, G, or H of this part. The notification shall be submitted no later than 7 calendar days after the applicable certification deadline is reached. (40 CFR75.61(a)(8))

c. **Monitoring plan submittals** (40 CFR 75.62)

i. Submission (40 CFR 75.62(a))

1) *Electronic*. Using the format specified in paragraph (c) of 40 CFR 75.62, the designated representative for an affected unit shall submit a complete, electronic, up-to-date monitoring plan file (except for hardcopy portions identified in paragraph (a)(2) of 40 CFR 75.62) to the Administrator as follows: no later than 21 days prior to the initial certification tests; at the time of each certification or recertification application submission; and (prior to or concurrent

with) the submittal of the electronic quarterly report for a reporting quarter where an update of the electronic monitoring plan information is required, either under 40 CFR 75.53(b) or elsewhere in this part. (40 CFR 75.62(a)(1))

2) *Hardcopy*. The designated representative shall submit all of the hardcopy information required under 40 CFR 75.53 to the appropriate EPA Regional Office and the appropriate State and/or local air pollution control agency prior to initial certification. Thereafter, the designated representative shall submit hardcopy information only if that portion of the monitoring plan is revised. The designated representative shall submit the required hardcopy information as follows: no later than 21 days prior to the initial certification test; with any certification or recertification application, if a hardcopy monitoring plan change is associated with the certification or recertification event; and within 30 days of any other event with which a hardcopy monitoring plan change is associated, pursuant to 40 CFR 75.53(b). Electronic submittal of all monitoring plan information, including hardcopy portions, is permissible provided that a paper copy of the hardcopy portions can be furnished upon request. (40 CFR 75.62(a)(2))

ii. Contents. Monitoring plans shall contain the information specified in 40 CFR 75.53 of this part (Requirements of Monitoring Plan for CEMS). See Condition S1.c.iii. (40 CFR 75.62(b))

iii. Monitoring plan (40 CFR 75.53)

1) General provisions (40 CFR 75.53(a))

(a) On and after January 1, 2009, the owner or operator shall meet the requirements of paragraphs (a), (b), (g), and (h) of 40 CFR 75.53 only. In addition, the provisions in paragraphs (g) and (h) of 40 CFR 75.53 that support a regulatory option provided in another section of this part must be followed if the regulatory option is used prior to January 1, 2009. (40 CFR 75.53(a)(1))

(b) The owner or operator of an affected unit shall prepare and maintain a monitoring plan. Except as provided in paragraphs (f) or (h) of 40 CFR 75.53 (as applicable), a monitoring plan shall contain sufficient information on the continuous emission or opacity monitoring systems, excepted methodology under 40 CFR 75.19 (Optional SO_2, NOx, and CO_2 emissions calculation for low mass emissions units), or excepted monitoring systems under appendix D or

E to this part and the use of data derived from these systems to demonstrate that all unit SO_2 emissions, NO_X emissions, CO_2 emissions, and opacity are monitored and reported. (40 CFR 75.53(a)(2))

2) Whenever the owner or operator makes a replacement, modification, or change in the certified CEMS, continuous opacity monitoring system, excepted methodology under 40 CFR 75.19, excepted monitoring system under appendix D or E to this part, or alternative monitoring system under subpart E of this part, including a change in the automated data acquisition and handling system or in the flue gas handling system, that affects information reported in the monitoring plan (e.g., a change to a serial number for a component of a monitoring system), then the owner or operator shall update the monitoring plan, by the applicable deadline specified in 40 CFR 75.62 (Monitoring plan submittals) or elsewhere in this part. (40 CFR 75.53(b))

3) Contents of the monitoring plan (40 CFR 75.53(g))

The requirements of paragraphs (g) and (h) of this section shall be met on and after January 1, 2009. Notwithstanding this requirement, the provisions of paragraphs (g) and (h) of 40 CFR 75.53 may be implemented prior to January 1, 2009, as follows. Each monitoring plan shall contain the information in paragraph (g)(1) of 40 CFR 75.53 in electronic format and the information in paragraph (g)(2) of 40 CFR 75.53 in hardcopy format. Electronic storage of all monitoring plan information, including the hardcopy portions, is permissible provided that a paper copy of the information can be furnished upon request for audit purposes.

(a) Electronic (40 CFR 75.53(g)(1))

(i) The facility ORISPL number developed by the Department of Energy and used in the National Allowance Data Base (or equivalent facility ID number assigned by EPA, if the facility does not have an ORISPL number). Also provide the following information for each unit and (as applicable) for each common stacks and/or pipe, and each multiple stack and/or pipe involved in the monitoring plan: (40 CFR 75.53(g)(1)(i))

(A) A representation of the exhaust configuration for the units in the monitoring plan. On and after April 27, 2011, provide the activation date and deactivation date (if applicable) of the configuration. Provide the ID number of each unit and assign a unique ID number to each common stack, common pipe multiple stack and/or multiple pipe associated with the unit(s) represented in the monitoring plan. For common and multiple stacks and/or pipes, provide the activation date and deactivation date (if applicable) of each stack and/or pipe; (40 CFR 75.53(g)(1)(i)(A))

(B) Identification of the monitoring system location(s) (e.g., at the unit-level, on the common stack, at each multiple stack, etc.). Provide an indicator (“flag”) if the monitoring location is at a bypass stack or in the ductwork (breeching); (40 CFR 75.53(g)(1)(i)(B))

(C) The stack exit height (ft) above ground level and ground level elevation above sea level, and the inside cross-sectional area (ft2) at the flue exit and at the flow monitoring location (for units with flow monitors, only). Also use appropriate codes to indicate the material(s) of construction and the shape(s) of the stack or duct cross-section(s) at the flue exit and (if applicable) at the flow monitor location. On and after April 27, 2011, provide the activation date and deactivation date (if applicable) for the information in this paragraph (g)(1)(i)(C); (40 CFR 75.53(g)(1)(i)(C))

(D) The type(s) of fuel(s) fired by each unit. Indicate the start and (if applicable) end date of combustion for each type of fuel, and whether the fuel is the primary, secondary, emergency, or startup fuel; (40 CFR 75.53(g)(1)(i)(D))

(E) The type(s) of emission controls that are used to reduce SO2, NOX, and particulate emissions from each unit. Also provide the installation date, optimization date, and retirement date (if applicable) of the emission controls, and indicate whether the controls are an original installation; (40 CFR 75.53(g)(1)(i)(E))

(F) Maximum hourly heat input capacity of each unit. On and after April 27, 2011, provide the activation date and deactivation date (if applicable) for this parameter; and (40 CFR 75.53(g)(1)(i)(F))

(G) A non-load based unit indicator (if applicable) for units that do not produce electrical or thermal output. (40 CFR 75.53(g)(1)(i)(G))

(ii) For each monitored parameter (e.g., SO_2, NO_X, flow, etc.) at each monitoring location, specify the monitoring methodology and the missing data approach for the parameter. If the unmonitored bypass stack approach is used for a particular parameter, indicate this by means of an appropriate code. Provide the activation date/hour, and deactivation date/hour (if applicable) for each monitoring methodology and each missing data approach. (40 CFR 75.53(g)(1)(ii))

(iii) For each required continuous emission monitoring system, each fuel flowmeter system, and each continuous opacity monitoring system, identify and describe the major monitoring components in the monitoring system (e.g., gas analyzer, flow monitor, opacity monitor, moisture sensor, fuel flowmeter, DAHS software, etc.). Other important components in the system (e.g., sample probe, PLC, data logger, etc.) may also be represented in the monitoring plan, if necessary. Provide the following specific information about each component and monitoring system: (40 CFR 75.53(g)(1)(iii))

(A) For each required monitoring system: (40 CFR 75.53(g)(1)(iii)(A))

(I) Assign a unique, 3-character alphanumeric identification code to the system; (40 CFR 75.53(g)(1)(iii)(A)(1))

(II) Indicate the parameter monitored by the system; (40 CFR 75.53(g)(1)(iii)(A)(2))

(III) Designate the system as a primary, redundant backup, non-redundant backup, data backup, or reference method backup system, as provided in 40 CFR 75.10(e) (Optional backup monitor requirements); and (40 CFR 75.53(g)(1)(iii)(A)(3))

(IV) Indicate the system activation date/hour and deactivation date/hour (as applicable). (40 CFR 75.53(g)(1)(iii)(A)(4))

(B) For each component of each monitoring system represented in the monitoring plan: (40 CFR 75.53(g)(1)(iii)(B))

(I) Assign a unique, 3-character alphanumeric identification code to the component; (40 CFR 75.53(g)(1)(iii)(B)(1))

(II) Indicate the manufacturer, model and serial number; (40 CFR 75.53(g)(1)(iii)(B)(3))

(III) Designate the component type; (40 CFR 75.53(g)(1)(iii)(B)(3))

(IV) For dual-span applications, indicate whether the analyzer component ID represents a high measurement scale, a low scale, or a dual range; (40 CFR 75.53(g)(1)(iii)(B)(4))

(V) For gas analyzers, indicate the moisture basis of measurement; (40 CFR 75.53(g)(1)(iii)(B)(5))

(VI) Indicate the method of sample acquisition or operation, (e.g., extractive pollutant concentration monitor or thermal flow monitor); and (40 CFR 75.53(g)(1)(iii)(B)(6))

(VII) Indicate the component activation date/hour and deactivation date/hour (as applicable). (40 CFR 75.53(g)(1)(iii)(B)(7))

(iv) Explicit formulas, using the component and system identification codes for the primary monitoring system, and containing all constants and factors required to derive the required mass emissions, emission rates, heat input rates, etc. from the hourly data recorded by the monitoring systems. Formulas using the system and component ID codes for backup monitoring systems are required only if different formulas for the same parameter are used for the primary and backup monitoring systems (e.g., if the primary system measures pollutant concentration on a different moisture basis from the backup system). Provide the equation number or other appropriate code for each emissions formula (e.g., use code F–1 if Equation F–1 in appendix F to this part is used to calculate SO_2 mass emissions). Also identify each emissions formula with a unique three character alphanumeric code. The formula effective start date/hour and inactivation date/hour (as applicable) shall be included for each formula. The owner or operator of a unit for which the optional low mass emissions excepted methodology in 40 CFR 75.19 is being used is not required to report such formulas. (40 CFR 75.53(g)(1)(iv))

(v) For each parameter monitored with CEMS, provide the following information: (40 CFR 75.53(g)(1)(v))

(A) Measurement scale (high or low); (40 CFR 75.53(g)(1)(v)(A))

(B) Maximum potential value (and method of calculation). If NO_X emission rate in lb/mmBtu is monitored, calculate and provide the maximum potential NO_X emission rate in addition to the maximum potential NO_X concentration; (40 CFR 75.53(g)(1)(v)(B))

(C) Maximum expected value (if applicable) and method of calculation; (40 CFR 75.53(g)(1)(v)(C))

(D) Span value(s) and full-scale measurement range(s); (40 CFR 75.53(g)(1)(v)(D))

(E) Daily calibration units of measure; (40 CFR 75.53(g)(1)(v)(E))

(F) Effective date/hour, and (if applicable) inactivation date/hour of each span value. On and after April 27, 2011, provide the activation date and deactivation date (if applicable) for the measurement scale and dual span information in paragraphs (g)(1)(v)(A), (g)(1)(v)(G), and (g)(1)(v)(H) of 40 CFR 75.53; (40 CFR 75.53(g)(1)(v)(F))

(G) An indication of whether dual spans are required. If two span values are required, then, on and after April 27, 2011, indicate whether an autoranging analyzer is used to represent the two measurement scales; and (40 CFR 75.53(g)(1)(v)(G))

(H) The default high range value (if applicable) and the maximum allowable low-range value for this option. (40 CFR 75.53(g)(1)(v)(H))

(vi) If the monitoring system or excepted methodology provides for the use of a constant, assumed, or default value for a parameter under specific circumstances, then include the following information for each such value for each parameter: (40 CFR 75.53(g)(1)(vi))

(A) Identification of the parameter; (40 CFR 75.53(g)(1)(vi)(A))

(B) Default, maximum, minimum, or constant value, and units of measure for the value; (40 CFR 75.53(g)(1)(vi)(B))

(C) Purpose of the value; (40 CFR 75.53(g)(1)(vi)(C))

(D) Indicator of use, i.e., during controlled hours, uncontrolled hours, or all operating hours; (40 CFR 75.53(g)(1)(vi)(D))

(E) Type of fuel; (40 CFR 75.53(g)(1)(vi)(E))

(F) Source of the value; (40 CFR 75.53(g)(1)(vi)(F))

(G) Value effective date and hour; (40 CFR 75.53(g)(1)(vi)(G))

(H) Date and hour that the value is no longer effective (if applicable); (40 CFR 75.53(g)(1)(vi)(H))

(I) For units using the excepted methodology under 40 CFR 75.19, the applicable SO_2 emission factor; and (40 CFR 75.53(g)(1)(vi)(I))

(J) On and after April 27, 2011, group identification code. (40 CFR 75.53(g)(1)(vi)(J))

(vii) Unless otherwise specified in section 6.5.2.1 of appendix A to this part, for each unit or common stacks on which hardware CEMS are installed: (40 CFR 75.53(g)(1)(vii))

(A) Maximum hourly gross load (in MW, rounded to the nearest MW, or steam load in 1000 lb/hr (i.e., klb/hr), rounded to the nearest klb/hr, or thermal output in mmBtu/hr, rounded to the nearest mmBtu/hr), for units that produce electrical or thermal output; (40 CFR 75.53(g)(1)(vii)(A))

(B) The upper and lower boundaries of the range of operation (as defined in section 6.5.2.1 of appendix A to this part), expressed in megawatts, thousands of lb/hr of steam, mmBtu/hr of thermal output, or ft/sec (as applicable); (40 CFR 75.53(g)(1)(vii)(B))

(C) Except for peaking units, identify the most frequently and second most frequently used load (or operating) levels (i.e., low, mid, or high) in accordance with section 6.5.2.1 of appendix A to this part, expressed in megawatts, thousands of lb/hr of steam, mmBtu/hr of thermal output, or ft/sec (as applicable); (40 CFR 75.53(g)(1)(vii)(C))

(D) Except for peaking units, an indicator of whether the second most frequently used load (or operating) level is designated as normal in section 6.5.2.1 of appendix A to this part; (40 CFR 75.53(g)(1)(vii)(D))

(E) The date of the data analysis used to determine the normal load (or operating) level(s) and the two most frequently-used load (or operating) levels (as applicable); and (40 CFR 75.53(g)(1)(vii)(E))

(F) Activation and deactivation dates and hours, when the maximum hourly gross load, boundaries of the range of operation, normal load (or operating) level(s) or two most frequently-used load (or operating) levels change and are updated. (40 CFR 75.53(g)(1)(vii)(F))

(b) Hardcopy (40 CFR 75.53(g)(2))

(i) Information, including (as applicable): Identification of the test strategy; protocol for the relative accuracy test audit; other relevant test information; calibration gas levels (percent of span) for the calibration error test and linearity check; calculations for determining maximum potential concentration, maximum expected concentration (if applicable), maximum potential flow rate, maximum potential NO_X emission rate, and span; and apportionment strategies under 40 CFR 75.10 through 75.18. (40 CFR 75.53(g)(2)(i))

(ii) Description of site locations for each monitoring component in the continuous emission or opacity monitoring systems, including schematic diagrams and engineering drawings specified in paragraphs (e)(2)(iv) and (e)(2)(v) of 40 CFR 75.53 and any other documentation that demonstrates each monitor location meets the appropriate siting criteria. (40 CFR 75.53(g)(2)(ii))

(iii) A data flow diagram denoting the complete information handling path from output signals of CEMS components to final reports. (40 CFR 75.53(g)(2)(iii))

(iv) For units monitored by a continuous emission or opacity monitoring system, a schematic diagram identifying entire gas handling system from boiler to stack for all affected units, using identification numbers for units, monitoring systems and components, and stacks corresponding to the identification numbers provided in paragraphs (g)(1)(i) and (g)(1)(iii) of 40 CFR 75.53. The schematic diagram must depict stack height and the height of any monitor locations. Comprehensive and/or separate schematic diagrams shall be used to describe groups of units using a common stack. (40 CFR 75.53(g)(2)(iv))

(v) For units monitored by a continuous emission or opacity monitoring system, stack and duct engineering diagrams showing the dimensions and location of fans, turning vanes, air preheaters, monitor components, probes, reference method sampling ports, and other equipment that affects the monitoring system location, performance, or quality control checks. (40 CFR 75.53(g)(2)(v))

d. **Initial certification or recertification application** (40 CFR 75.63)

i. Submission (40 CFR 75.63(a))

The designated representative for an affected unit or a combustion source shall submit applications and reports as follows:

1) Recertifications and diagnostic testing (40 CFR 75.63(a)(2))

(a) Within 45 days after completing all recertification tests under 40 CFR 75.20(b), submit to the Administrator the electronic information required by paragraph (b)(1) of 40 CFR 75.63. Except for subpart E applications for alternative monitoring systems or unless specifically requested by the Administrator, do not submit a hardcopy of the test data and results to the Administrator. (40 CFR 75.63(a)(2)(i))

(b) Within 45 days after completing all recertification tests under 40 CFR 75.20(b), submit the hardcopy information required by paragraph (b)(2) of 40 CFR 75.63 to the applicable EPA Regional Office and the appropriate State and/or local air pollution control agency. The applicable EPA Regional Office or appropriate State or local air pollution control agency may waive the requirement to provide hardcopy recertification test and data results. The applicable EPA Regional Office or the appropriate State or local air pollution control agency may also discontinue the waiver and reinstate the requirement of this paragraph to provide a hardcopy report of the recertification test data and results. (40 CFR 75.63(a)(2)(ii))

(c) Notwithstanding the requirements of paragraphs (a)(2)(i) and (a)(2)(ii) of 40 CFR 75.63, for an event for which the Administrator determines that only diagnostic tests (*see* 40 CFR 75.20(b)) are required rather than recertification testing, no hardcopy submittal is required; however, the results of all diagnostic test(s) shall be submitted prior to or concurrent with the electronic quarterly report required under 40 CFR 75.64. Notwithstanding the requirement of 40 CFR 75.59(e), for DAHS (missing data and formula) verifications, no hardcopy submittal is required; the owner or operator shall keep these test results on-site in a format suitable for inspection. (40 CFR 75.63(a)(2)(iii))

ii. Contents (40 CFR 75.63(b))

Each application for recertification shall contain the following information, as applicable:

1) Electronic (75.63(b)(1))

(a) A complete, up-to-date version of the electronic portion of the monitoring plan, according to 40 CFR 75.53(e) and (f), in the format specified by the Administrator. (75.63(b)(1)(i))

(b) The results of the test(s) required by 40 CFR 75.20, including the type of test conducted, testing date, information required by 40 CFR 75.59 (Certification, quality assurance, and quality control record provisions), and the results of any failed tests that affect data validation. (75.63(b)(1)(ii))

2) Hardcopy (75.63(b)(2))

(a) Any changed portions of the hardcopy monitoring plan information required under 40 CFR 75.53(e) and (f). Electronic submittal of all monitoring plan information, including the hardcopy portions, is permissible, provided that a paper copy can be furnished upon request. (75.63(b)(2)(i))

(b) The results of the test(s) required by 40 CFR 75.20, including the type of test conducted, testing date, information required by 40 CFR 75.59(a)(9) (See Condition S1.a.ii.), and the results of any failed tests that affect data validation. (75.63(b)(2)(ii))

(c) Designated representative signature certifying the accuracy of the submission. (75.63(b)(2)(ii))

iii. Format (40 CFR 75.63(c))

The electronic portion of each certification or recertification application shall be submitted in a format to be specified by the Administrator. The hardcopy test results shall be submitted in a format suitable for review and shall include the information in 40 CFR 75.59(a)(9) (See Condition S1.a.ii.)

e. **Quarterly reports** (40 CFR 75.64)

i. Electronic submission (40 CFR 75.64(a))

The designated representative for an affected unit shall electronically report the data and information in paragraphs (a) and (c) of 40 CFR 75.64 to the Administrator quarterly, beginning with the data from the earlier of the calendar quarter corresponding to the date of provisional certification or the calendar quarter corresponding to the relevant deadline for initial certification in 40 CFR 75.4(a), and (c). The initial quarterly report shall contain hourly data beginning with the hour of provisional certification or the hour corresponding to the relevant certification deadline, whichever is earlier. For any provisionally-certified monitoring system, 40 CFR

75.20(a)(3) shall apply for initial certifications, and 40 CFR 75.20(b)(5) shall apply for recertifications. Each electronic report must be submitted to the Administrator within 30 days following the end of each calendar quarter. On and after January 1, 2009, the owner or operator shall meet the requirements of paragraphs (a)(3) through (a)(15) of 40 CFR 75.64 only. Each electronic report shall also include the date of report generation. (The electronic quarterly reports are submitted to EPA)

1) Facility identification information, including: (40 CFR 75.64(a)(3))

   (a) Facility/ORISPL number; (40 CFR 75.64(a)(3)(i))
   (b) Calendar quarter and year for the data contained in the report; and (40 CFR 75.64(a)(3)(ii))
   (c) Version of the electronic data reporting format used for the report. (40 CFR 75.64(a)(3)(iii))

2) In accordance with 40 CFR 75.62(a)(1), if any monitoring plan information required in 40 CFR 75.53 (monitoring plan requirements) requires an update, either under 40 CFR 75.53(b) or elsewhere in this part, submission of the electronic monitoring plan update shall be completed prior to or concurrent with the submittal of the quarterly electronic data report for the appropriate quarter in which the update is required. (40 CFR 75.64(a)(4))

3) The daily calibration error test and daily interference check information required in 75.59(a)(1) and (a)(2) must always be included in the electronic quarterly emissions report. All other certification, quality assurance, and quality control information in 75.59 that is not excluded from electronic reporting under paragraph (a)(2) or (a)(7) of 40 CFR 75.64 shall be submitted separately, either prior to or concurrent with the submittal of the relevant electronic quarterly emissions report. However, reporting of the information in 75.59(a)(9)(x) is not required until September 26, 2011, and reporting of the information in 75.59(a)(15), (b)(6), and (d)(4) is not required until March 27, 2012. (40 CFR 75.64(a)(5))

4) The information and hourly data required in 40 CFR 75.57 through 75.59 (General recordkeeping provisions; General recordkeeping for specific situations; Certification, quality assurance, and quality control record provisions), and daily calibration error test data, daily interference check, and off-line calibration demonstration information required in 40 CFR 75.59(a)(1) and (2). (40 CFR 75.64(a)(6))

5) Notwithstanding the requirements of paragraphs (a)(4) through (a)(6) of 40 CFR 75.64, the following information is excluded from electronic reporting: (40 CFR 75.64(a)(7))

(a) Descriptions of adjustments, corrective action, and maintenance; (40 CFR 75.64(a)(7)(i))

(b) Information which is incompatible with electronic reporting (e.g., field data sheets, lab analyses, quality control plan); (40 CFR 75.64(a)(7)(ii))

(c) Opacity data listed in 40 CFR 75.57(f), and in 40 CFR 75.59(a)(8); (40 CFR 75.64(a)(7)(iii))

(d) For units with SO_2 or NO_X add-on emission controls that do not elect to use the approved site-specific parametric monitoring procedures for calculation of substitute data, the information in 40 CFR 75.58(b)(3); (40 CFR 75.64(a)(7)(iv))

(e) Information required by 40 CFR 75.57(h) concerning the causes of any missing data periods and the actions taken to cure such causes; (40 CFR 75.64(a)(7)(v))

(f) Hardcopy monitoring plan information required by 40 CFR 75.53 and hardcopy test data and results required by 40 CFR 75.59; (40 CFR 75.64(a)(7)(vi))

(g) Records of flow monitor and moisture monitoring system polynomial equations, coefficients, or “K” factors required by 40 CFR 75.59(a)(5)(vi) or 40 CFR 75.59(a)(5)(vii); (40 CFR 75.64(a)(7)(vii))

(h) Daily fuel sampling information required by 40 CFR 75.58(c)(3)(i) for units using assumed values under appendix D of this part; (40 CFR 75.64(a)(7)(viii))

(i) Information required by 40 CFR 75.59(b)(1)(vi), (vii), (viii), (ix), and (xiii), and (b)(2)(iii) and (iv) concerning fuel flowmeter accuracy tests and transmitter/transducer accuracy tests; (40 CFR 75.64(a)(7)(ix))

(j) Stratification test results required as part of the RATA supplementary records under 40 CFR 75.59(a)(7); (40 CFR 75.64(a)(7)(x))

(k) Data and results of RATAs that are aborted or invalidated due to problems with the reference method or operational problems with the unit and data and results of linearity checks that are aborted or invalidated due to problems unrelated to monitor performance; (40 CFR 75.64(a)(7)(xi))

(l) Supplementary RATA information required under 40 CFR 75.59(a)(7)(i) through 40 CFR 75.59(a)(7)(v) (supporting information for RATA), except that: (40 CFR 75.64(a)(7)(xii))

(i) The applicable data elements under 40 CFR 75.59(a)(7)(ii)(A) through (T) and under 40 CFR 75.59(a)(7)(iii)(A) through (M) (supporting information for RATA using Method 2) shall be reported for flow RATAs at circular or rectangular stacks (or ducts) in which angular compensation for yaw and/or pitch angles is used (*i.e.*, Method 2F or 2G in appendices A–1 and A–2 to part 60 of this chapter), with or without wall effects adjustments; (40 CFR 75.64(a)(7)(xii)(A))

(ii) The applicable data elements under 40 CFR 75.59(a)(7)(ii)(A) through (T) and under 40 CFR 75.59(a)(7)(iii)(A) through (M) (supporting information for RATA using Method 2) shall be reported for any flow RATA run at a circular stack in which Method 2 in appendices A–1 and A–2 to part 60 of this chapter is used and a wall effects adjustment factor is determined by direct measurement; (40 CFR 75.64(a)(7)(xii)(B))

(iii) The data under 40 CFR 75.59(a)(7)(ii)(T) (supporting information for RATA using Method 2) shall be reported for all flow RATAs at circular stacks in which Method 2 in appendices A–1 and A–2 to part 60 of this chapter is used and a default wall effects adjustment factor is applied. (40 CFR 75.64(a)(7)(xii)(C))

6) Tons (rounded to the nearest tenth) of SO_2 emitted during the quarter and cumulative SO_2 emissions for the calendar year. (40 CFR 75.64(a)(8))

7) Average NO_X emission rate (lb/mmBtu, rounded to the nearest thousandth) during the quarter and cumulative NO_X emission rate for the calendar year. (40 CFR 75.64(a)(9))

8) Tons of CO_2 emitted during quarter and cumulative CO_2 emissions for calendar year. (40 CFR 75.64(a)(10))

9) Total heat input (mmBtu) for quarter and cumulative heat input for calendar year. (40 CFR 75.64(a)(11))

10) Unit or stack or common pipe header operating hours for quarter and cumulative unit or stack or common pipe header operating hours for calendar year. (40 CFR 75.64(a)(12))

ii. Compliance certification (40 CFR 75.64(c))

The designated representative shall submit a certification in support of each quarterly emissions monitoring report based on reasonable inquiry of those persons with primary responsibility for ensuring that all of the unit's emissions are correctly and fully monitored. The certification shall indicate whether the monitoring data submitted were recorded in accordance with the applicable requirements of this part including the quality control and quality assurance procedures and specifications of this part and its appendices, and any such requirements, procedures and specifications of an applicable excepted or approved alternative monitoring method. For a unit with add-on emission controls, the designated representative shall also include a certification, for all hours where data are substituted following the provisions of 40 CFR 75.34(a)(1) (missing data substitution procedures for units with add-on emission controls), that the add-on emission controls were operating within the range of parameters listed in the monitoring plan and that the substitute values recorded during the quarter do not systematically underestimate SO_2 or NO_X emissions, pursuant to 40 CFR 75.34 (Missing Data Substitution Procedure).

iii. Method of submission (40 CFR 75.64(f))

Beginning with the quarterly report for the first quarter of the year 2001, all quarterly reports shall be submitted to EPA by direct computer-to-computer electronic transfer via EPA-provided software, unless otherwise approved by the Administrator.

iv. At his or her discretion, the DR may include important explanatory text or comments with an electronic quarterly report submittal, so long as the information is provided in a format that is compatible with the other data required to be reported under 40 CFR 75.64. (40 CFR 75.64(g))

f. **Opacity reports** (40 CFR 75.65)

The owner or operator or designated representative shall report excess emissions of opacity recorded under 40 CFR 75.57(f) (opacity recordkeeping requirements) to the applicable State or local air pollution control agency.

Attachment F - Fugitive Dust Control Plan for Paved & Unpaved Roads
(Submitted 6/28/2013 and Approved 6/5/2014)

Executive Summary

Louisville Gas and Electric Company (LG&E) is required to maintain and operate the Mill Creek Generating Station in a manner consistent with good air pollution control practices for minimizing emissions, as defined in KRS Chapter 77 Air Pollution Control.

This Fugitive Dust Control Plan has been prepared to comply with the requirements of Regulation 1.14 of the Louisville Metro Air Pollution Control District (LMAPCD) and has been developed at the request of the LMAPCD.

Louisville Metro
Air Pollution Control District
850 Barret Ave.
Louisville, KY 40204-1745
502-574-6000

Introduction

This plan identifies measures to control fugitive particulate emissions from paved and unpaved roads at LG&E's Mill Creek Generating Station, 14660 Dixie Highway. This plan is divided into three sections:

1. Site Description
2. Control measures to minimize fugitive particulate emissions
3. Primary Contact List

The Plant Manager is responsible for implementing the procedures outlined in this Fugitive Dust Control Plan. This Plan will be maintained within the Environmental files at the Mill Creek Generating Station.

Plant Manager: Mike Kirkland

Section 1 – Site Description

LG&E's Mill Creek Generating Station (Mill Creek) is located in southwestern Louisville at 14660 Dixie Highway. Mill Creek generates electric energy for local and remote distribution. Coal is the primary fuel utilized in electric generation at Mill Creek. Coal is delivered on the site by rail car and barge with shipments either placed in a storage pile or fed directly to the electric generation process.

The Mill Creek site consists of approximately 500 acres along the Ohio River. The existing operation is spread throughout the property. The primary emission generating activities at the facility consist of four operational coal-fired boilers (emission units U1, U2, U3 and U4), used for generation of electricity via steam turbines and generators. All boiler units are equipped with electrostatic precipitators (ESP), flue gas desulfurization systems (FGD), and low NOx burners for emission control. Units 3 and 4 are also equipped with Selective Catalytic Reduction (SCR).

The Mill Creek site utilizes unpaved roads and parking lots, and paved roads for its daily operational needs. See attached Mill Creek Site Map.

Unpaved Roads

Unpaved roads at the Mill Creek site are typically graveled with #57 grade aggregate. Other grades of gravel can be used upon the approval of the District. Unpaved roads access should be limited to contractors, employees, agency personnel, and others that may be provided access in the course of performing required operational duties.

Potential fugitive dust from unpaved roads may be caused by:

- Dry road conditions;
- Wind erosion;
- Vehicle traffic; and
- Material fallout from vehicle traffic.

Paved Roads

The paved roads are asphalt or concrete surfaced. Paved roads access should be limited to contractors, employees, agency personnel, and others that may be provided access in the course of performing required operational duties.

Potential fugitive dust from paved roads may include:

- Material tracked from unpaved surfaces onto paved roads by vehicle traffic; and
- Material fallout from vehicle traffic.
- Construction activities.

Section 2 - Control Measures to Minimize Fugitive Particulate Emissions

The following measures will be implemented to control dust from unpaved and paved roads.

Site Monitoring

- In the event dry weather persists, the frequency of watering will be adjusted to control fugitive dust emissions. Monitoring is performed throughout each business day by multiple LG&E and contract personnel. Areas that require additional/beyond normal attention will be logged by the water truck driver(s). Additional/beyond normal conditions are defined as periods of time outside daily business hours and during extreme weather events.
- If it is determined that weather conditions have contributed to the control of fugitive dust emissions, watering operations may be suspended until such time as it appears necessary

for the control of fugitive dust emissions. In addition, watering operations will be suspended if watering has contributed to unsafe conditions for either equipment or personnel.

Unpaved Roads

- Mill Creek utilizes water truck(s) to keep the roadways and entrance and exit areas within the site wet in order to control fugitive dust emissions. An additional water truck, as-needed, will be used during the summer months (typically June through September) as a back-up or to assist with watering efforts during hot/windy weather.
- The watering operations will be at a frequency of at least once every two hours for the active unpaved roads (i.e., scheduled to be used for the whole shift). Further, the facility will water more frequently if there is visible evidence of fugitive dust emissions (e.g., dust clouds resulting from wind). The only exception to the once per two hours of water operations is when the unpaved roads are not active (i.e., scheduled not to be used for the whole shift) or during times when precipitation such as rainfall, snow, and ice have adequately suppressed the dust or have contributed to unsafe conditions for equipment or personnel. (See Section 2 Site Monitoring on Page 3.)
- Mill Creek will maintain daily records for the watering operations performed on all unpaved roads, or a statement that rain occurred. If a statement that rain occurred is made it shall include the start and stop time of rainfall. All records shall include the date, and name of the person making the entry.

Paved Roads

- All passenger vehicles, including employee vehicles entering and leaving the site, will be limited to paved roads and parking lots to prevent the generation of dust, unless required for direct performance of operational duties. Should operational duties cause dust to transfer to paved roads, the material will be cleaned using a water truck side spray or wet street sweeper or water hose, as needed.
- Roads will be maintained in such a manner as to prevent the tracking of debris onto any public roads.
- Mill Creek utilizes water truck(s) to keep the paved roadways, entrance areas, and exit areas within the site wet in order to control fugitive dust emissions. An additional water truck will be used, as-needed, during the summer months (typically June through September) as a back-up or to assist with watering efforts during hot/windy weather.
- For 8 hours per weekday, watering operations will be continuous until the roads are saturated. Weekend operation will be planned on an as-needed basis, based on weather forecast.

Construction Activities

- To minimize the material track-out and transfer onto paved roads, construction vehicles will be cleaned periodically to reduce the accumulation of material.
- Additional watering of the roadways used for construction activities (e.g., controls upgrade project), during extremely dry weather conditions, will be done on an as-needed basis. This

determination will be made on a timely basis by appropriate facility personnel. (Also see Section 2 Site Monitoring on Page 3.)
- Mitigation procedures may include wetting of the material to prevent fugitive emissions from trucks hauling dry material likely to become airborne. All trucks leaving Mill Creek property are required to be covered.
- The main plant road from Gate 3 to Gate 5 will use a wet street sweeper, as needed.
- All waste materials generated during construction will be collected and stored in labeled metal or plastic dumpsters and removed from the construction site by a licensed waste management contractor.

Section 3 - Primary Contact List

Personnel involved in activities that produce fugitive particulate emissions are expected to comply with the requirements listed within this Mill Creek Fugitive Dust Control Plan. The following primary contact list is intended for use only by personnel employed by the LMAPCD and is being provided for LMAPCD's use as needed to obtain information regarding any questions or issues surrounding the processes contained within this plan. In the absence of the plant manager, all operation, production and maintenance managers and on-shift operation supervisors have full authority to make the necessary fugitive dust emission mitigation decisions. The contacts listed below are appropriate during and after business hours.

1) Production Leader, 24 Hour Support, Mill Creek Station
502-933-6700 (Office)

2) Michelle Beumel, Environmental Coordinator, Mill Creek Station
502-933-6527 (Office)

3) Brandan Burfict, Environmental Engineer, Environmental Air Section
502-627-2791 (Office)

4) Mike Stevens, Production Supervisor/Compliance, Mill Creek Station
502-933-6518 (Office)

5) Joe Didelot, Plant Manager, Mill Creek Station
502-933-6559 (Office)

6) Philip Imber, Manager, Environmental Air Section, LGE/KU
502-627-4144 (Office)

LG&E Mill Creek Station
Fugitive Dust Control Plan for Paved and Unpaved Roads
5/6/2014

Paved Roads
Unpaved Roads
Additional Potential Source Areas

Attachment G – Cross-State Air Pollution Rule (CSAPR)

The owner or operator shall comply with the following requirements unless there are more current promulgated regulations:

I. Description of CSAPR Monitoring Provisions

The CSAPR subject units, and the unit-specific monitoring provisions at this source, are identified in the following tables. These units are subject to the requirements for the CSAPR NO_X Annual Trading Program, CSAPR NOX Ozone Season Group 2 Trading Program, and CSAPR SO_2 Group 1 Trading Program.

Unit ID: Unit 1, non-peaking coal-fired boiler with natural gas backup					
Parameter	CEMS requirements pursuant to 40 CFR part 75, subpart B (for SO_2 monitoring) and 40 CFR part 75, subpart H (for NO_X monitoring)	Excepted monitoring system requirements for gas- and oil-fired units pursuant to 40 CFR part 75, appendix D	Excepted monitoring system requirements for gas- and oil-fired peaking units pursuant to 40 CFR part 75, appendix E	Low Mass Emissions excepted monitoring (LME) requirements for gas- and oil-fired units pursuant to 40 CFR 75.19	EPA-approved alternative monitoring system requirements pursuant to 40 CFR part 75, subpart E
SO_2	X		----------------		
NO_X	X	-------------			
Heat input	X		----------------		

Unit ID: Unit 2, non-peaking coal-fired boiler with natural gas backup					
Parameter	CEMS requirements pursuant to 40 CFR part 75, subpart B (for SO_2 monitoring) and 40 CFR part 75, subpart H (for NO_X monitoring)	Excepted monitoring system requirements for gas- and oil-fired units pursuant to 40 CFR part 75, appendix D	Excepted monitoring system requirements for gas- and oil-fired peaking units pursuant to 40 CFR part 75, appendix E	Low Mass Emissions excepted monitoring (LME) requirements for gas- and oil-fired units pursuant to 40 CFR 75.19	EPA-approved alternative monitoring system requirements pursuant to 40 CFR part 75, subpart E
SO_2	X		----------------		
NO_X	X	-------------			
Heat input	X		----------------		

Unit ID: Unit 3, non-peaking coal-fired boiler with natural gas backup

Parameter	CEMS requirements pursuant to 40 CFR part 75, subpart B (for SO_2 monitoring) and 40 CFR part 75, subpart H (for NO_X monitoring)	Excepted monitoring system requirements for gas- and oil-fired units pursuant to 40 CFR part 75, appendix D	Excepted monitoring system requirements for gas- and oil-fired peaking units pursuant to 40 CFR part 75, appendix E	Low Mass Emissions excepted monitoring (LME) requirements for gas- and oil-fired units pursuant to 40 CFR 75.19	EPA-approved alternative monitoring system requirements pursuant to 40 CFR part 75, subpart E
SO_2	X		----------------		
NO_X	X	-------------			
Heat input	X		----------------		

Unit ID: Unit 4, non-peaking coal-fired boiler with natural gas backup					
Parameter	CEMS requirements pursuant to 40 CFR part 75, subpart B (for SO_2 monitoring) and 40 CFR part 75, subpart H (for NO_X monitoring)	Excepted monitoring system requirements for gas- and oil-fired units pursuant to 40 CFR part 75, appendix D	Excepted monitoring system requirements for gas- and oil-fired peaking units pursuant to 40 CFR part 75, appendix E	Low Mass Emissions excepted monitoring (LME) requirements for gas- and oil-fired units pursuant to 40 CFR 75.19	EPA-approved alternative monitoring system requirements pursuant to 40 CFR part 75, subpart E
SO_2	X		----------------		
NO_X	X	-------------			
Heat input	X		----------------		

1. The above description of the monitoring used by a unit does not change, create an exemption from, or otherwise affect the monitoring, recordkeeping, and reporting requirements applicable to the unit under 40 CFR 97.430 through 97.435 (CSAPR NO_X Annual Trading Program), 97.830 through 97.835 (CSAPR NOX Ozone Season Group 2 Trading Program), and 97.630 through 97.635 (CSAPR SO_2 Group 1 Trading Program). The monitoring, recordkeeping and reporting requirements applicable to each unit are included below in the standard conditions for the applicable CSAPR trading programs.

2. Owners and operators must submit to the Administrator a monitoring plan for each unit in accordance with 40 CFR 75.53, 75.62 and 75.73, as applicable. The monitoring plan for each unit is available at the EPA's website at http://www.epa.gov/airmarkets/emissions/monitoringplans.html.

3. Owners and operators that want to use an alternative monitoring system must submit to the Administrator a petition requesting approval of the alternative monitoring system in accordance with 40 CFR part 75, subpart E and 40 CFR 75.66 and 97.435 (CSAPR NO_X Annual Trading Program), 97.835 (CSAPR NOX Ozone Season Group 2 Trading Program), and 97.635 (CSAPR SO_2 Group 1 Trading Program). The Administrator's

response approving or disapproving any petition for an alternative monitoring system is available on the EPA's website at http://www.epa.gov/airmarkets/emissions/petitions.html.

4. Owners and operators that want to use an alternative to any monitoring, recordkeeping, or reporting requirement under 40 CFR 97.430 through 97.434 (CSAPR NO_X Annual Trading Program), 97.830 through 97.834 (CSAPR NOX Ozone Season Group 2 Trading Program), and 97.630 through 97.634 (CSAPR SO_2 Group 1 Trading Program must submit to the Administrator a petition requesting approval of the alternative in accordance with 40 CFR 75.66 and 97.435 (CSAPR NO_X Annual Trading Program), 97.835 (CSAPR NOX Ozone Season Group 2 Trading Program), and 97.635 (CSAPR SO_2 Group 1 Trading Program). The Administrator's response approving or disapproving any petition for an alternative to a monitoring, recordkeeping, or reporting requirement is available on EPA's website at http://www.epa.gov/airmarkets/emissions/petitions.html.

5. The descriptions of monitoring applicable to the unit included above meet the requirement of 40 CFR 97.430 through 97.434 (CSAPR NO_X Annual Trading Program), 97.830 through 97.834 (CSAPR NOX Ozone Season Group 2 Trading Program), and 97.630 through 97.634 (CSAPR SO_2 Group 1 Trading Program), and therefore minor permit modification procedures, in accordance with 40 CFR 70.7(e)(2)(i)(B) or 71.7(e)(1)(i)(B), may be used to add to or change this unit's monitoring system description.

II. CSAPR NO_X Annual Trading Program requirements (40 CFR 97, Subpart AAAAA)

(a) Designated representative requirements.

The owners and operators shall comply with the requirement to have a designated representative, and may have an alternate designated representative, in accordance with 40 CFR 97.413 through 97.418.

(b) Emissions monitoring, reporting, and recordkeeping requirements.

(1) The owners and operators, and the designated representative, of each CSAPR NO_X Annual source and each CSAPR NO_X Annual unit at the source shall comply with the monitoring, reporting, and recordkeeping requirements of 40 CFR 97.430 (general requirements, including installation, certification, and data accounting, compliance deadlines, reporting data, prohibitions, and long-term cold storage), 97.431 (initial monitoring system certification and recertification procedures), 97.432 (monitoring system out-of-control periods), 97.433 (notifications concerning monitoring), 97.434 (recordkeeping and reporting, including monitoring plans, certification applications, quarterly reports, and compliance certification), and 97.435 (petitions for alternatives to monitoring, recordkeeping, or reporting requirements).

(2) The emissions data determined in accordance with 40 CFR 97.430 through 97.435 shall be used to calculate allocations of CSAPR NO_X Annual allowances under 40 CFR 97.411(a)(2) and (b) and 97.412 and to determine compliance with the CSAPR NO_X Annual emissions limitation and assurance provisions under paragraph (c) below, provided that, for each monitoring location from which mass emissions are reported, the mass emissions amount used in calculating such allocations and determining such compliance shall be the mass emissions amount for the monitoring location determined in accordance with 40 CFR 97.430 through 97.435 and rounded to the nearest ton, with any fraction of a ton less than 0.50 being deemed to be zero.

(c) NO_X emissions requirements.

(1) CSAPR NO_X Annual emissions limitation.

(i). As of the allowance transfer deadline for a control period in a given year, the owners and operators of each CSAPR NO_X Annual source and each CSAPR NO_X Annual unit at the source shall hold, in the source's compliance account, CSAPR NO_X Annual allowances available for deduction for such control period under 40 CFR 97.424(a) in an amount not less than the tons of total NO_X emissions for such control period from all CSAPR NO_X Annual units at the source.

(ii). If total NO_X emissions during a control period in a given year from the CSAPR NO_X Annual units at a CSAPR NO_X Annual source are in excess of the CSAPR NO_X Annual emissions limitation set forth in paragraph (c)(1)(i) above, then:

(A). The owners and operators of the source and each CSAPR NO_X Annual unit at the source shall hold the CSAPR NO_X Annual allowances required for deduction under 40 CFR 97.424(d); and

(B). The owners and operators of the source and each CSAPR NO_X Annual unit at the source shall pay any fine, penalty, or assessment or comply with any other remedy imposed, for the same violations, under the Clean Air Act, and each ton of such excess emissions and each day of such control period shall constitute a separate violation of 40 CFR part 97, subpart AAAAA and the Clean Air Act.

(2) CSAPR NO_X Annual assurance provisions.

(i). If total NO_X emissions during a control period in a given year from all CSAPR NO_X Annual units at CSAPR NO_X Annual sources in the state exceed the state assurance level, then the owners and operators of such sources and units in each group of one or more sources and units having a common designated representative for such control period, where the common designated representative's share of such NO_X emissions during such control period exceeds the common designated representative's assurance level for the state and such control period, shall hold (in the assurance account established for the owners and operators of such group) CSAPR NO_X Annual allowances available for deduction for such control period under 40 CFR 97.425(a) in an amount equal to two times the product (rounded to the nearest whole number), as determined by the Administrator in accordance with 40 CFR 97.425(b), of multiplying— (A) The quotient of the amount by which the common designated representative's share of such NO_X emissions exceeds the common designated representative's assurance level divided by the sum of the amounts, determined for all common designated representatives for such sources and units in the state for such control period, by which each common designated representative's share of such NO_X emissions exceeds the respective common designated representative's assurance level; and (B) The amount by which total NO_X emissions from all CSAPR NO_X Annual units at CSAPR NO_X Annual sources in the state for such control period exceed the state assurance level.

(ii). The owners and operators shall hold the CSAPR NO_X Annual allowances required under paragraph (c)(2)(i) above, as of midnight of November 1 (if it is a business day), or midnight of the first business day thereafter (if November 1 is not a business day), immediately after such control period.

(iii). Total NO_X emissions from all CSAPR NO_X Annual units at CSAPR NO_X Annual sources in the State during a control period in a given year exceed the state assurance level if such total NO_X emissions exceed the sum, for such control period, of the state NO_X Annual trading budget under 40 CFR 97.410(a) and the state's variability limit under 40 CFR 97.410(b).

(iv). It shall not be a violation of 40 CFR part 97, subpart AAAAA or of the Clean Air Act if total NO_X emissions from all CSAPR NO_X Annual units at CSAPR NO_X Annual sources in the State during a control period exceed the state assurance level or if a common designated representative's share of total NO_X emissions from the

CSAPR NO_X Annual units at CSAPR NO_X Annual sources in the state during a control period exceeds the common designated representative's assurance level.

(v). To the extent the owners and operators fail to hold CSAPR NO_X Annual allowances for a control period in a given year in accordance with paragraphs (c)(2)(i) through (iii) above,

(A). The owners and operators shall pay any fine, penalty, or assessment or comply with any other remedy imposed under the Clean Air Act; and

(B). Each CSAPR NOX Annual allowance that the owners and operators fail to hold for such control period in accordance with paragraphs (c)(2)(i) through (iii) above and each day of such control period shall constitute a separate violation of 40 CFR part 97, subpart AAAAA and the Clean Air Act.

(3) Compliance periods.

(i). A CSAPR NO_X Annual unit shall be subject to the requirements under paragraph (c)(1) above for the control period starting on the later of January 1, 2015, or the deadline for meeting the unit's monitor certification requirements under 40 CFR 97.430(b) and for each control period thereafter.

(ii). A CSAPR NO_X Annual unit shall be subject to the requirements under paragraph (c)(2) above for the control period starting on the later of January 1, 2017 or the deadline for meeting the unit's monitor certification requirements under 40 CFR 97.430(b) and for each control period thereafter.

(4) Vintage of allowances held for compliance.

(i). A CSAPR NO_X Annual allowance held for compliance with the requirements under paragraph (c)(1)(i) above for a control period in a given year must be a CSAPR NO_X Annual allowance that was allocated for such control period or a control period in a prior year.

(ii). A CSAPR NO_X Annual allowance held for compliance with the requirements under paragraphs (c)(1)(ii)(A) and (2)(i) through (iii) above for a control period in a given year must be a CSAPR NO_X Annual allowance that was allocated for a control period in a prior year or the control period in the given year or in the immediately following year.

(5) Allowance Management System requirements. Each CSAPR NO_X Annual allowance shall be held in, deducted from, or transferred into, out of, or between Allowance Management System accounts in accordance with 40 CFR part 97, subpart AAAAA.

(6) Limited authorization. A CSAPR NO_X Annual allowance is a limited authorization to emit one ton of NO_X during the control period in one year. Such authorization is limited in its use and duration as follows:

(i). Such authorization shall only be used in accordance with the CSAPR NO_X Annual Trading Program; and

(ii). Notwithstanding any other provision of 40 CFR part 97, the Administrator has the authority to terminate or limit the use and duration of such authorization to the extent the Administrator determines is necessary or appropriate to implement any provision of the Clean Air Act.

(7) Property right. A CSAPR NO_X Annual allowance does not constitute a property right.

(d) Title V permit revision requirements.

(1) No title V permit revision shall be required for any allocation, holding, deduction, or transfer of CSAPR NO_X Annual allowances in accordance with 40 CFR part 97, subpart AAAAA.

(2) This permit incorporates the CSAPR emissions monitoring, recordkeeping and reporting requirements pursuant to 40 CFR 97.430 through 97.435, and the requirements for a continuous emission monitoring system (pursuant to 40 CFR part 75, subparts B and H), an excepted monitoring system (pursuant to 40 CFR part 75, appendices D and E), a low mass emissions excepted monitoring methodology (pursuant to 40 CFR 75.19), and an alternative monitoring system (pursuant to 40 CFR part 75, subpart E). Therefore, the Description of CSAPR Monitoring Provisions table for units identified in this permit may be added to, or changed, in this title V permit using minor permit modification procedures in accordance with 40 CFR 97.406(d)(2) and 70.7(e)(2)(i)(B) or 71.7(e)(1)(i)(B).

(e) Additional recordkeeping and reporting requirements.

(1) Unless otherwise provided, the owners and operators of each CSAPR NO_X Annual source and each CSAPR NO_X Annual unit at the source shall keep on site at the source each of the following documents (in hardcopy or electronic format) for a period of 5 years from the date the document is

created. This period may be extended for cause, at any time before the end of 5 years, in writing by the Administrator.

(i). The certificate of representation under 40 CFR 97.416 for the designated representative for the source and each CSAPR NO_X Annual unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation; provided that the certificate and documents shall be retained on site at the source beyond such 5-year period until such certificate of representation and documents are superseded because of the submission of a new certificate of representation under 40 CFR 97.416 changing the designated representative.

(ii). All emissions monitoring information, in accordance with 40 CFR part 97, subpart AAAAA.

(iii). Copies of all reports, compliance certifications, and other submissions and all records made or required under, or to demonstrate compliance with the requirements of, the CSAPR NO_X Annual Trading Program.

(2) The designated representative of a CSAPR NO_X Annual source and each CSAPR NO_X Annual unit at the source shall make all submissions required under the CSAPR NO_X Annual Trading Program, except as provided in 40 CFR 97.418. This requirement does not change, create an exemption from, or otherwise affect the responsible official submission requirements under a title V operating permit program in 40 CFR parts 70 and 71.

(f) Liability.

(1) Any provision of the CSAPR NO_X Annual Trading Program that applies to a CSAPR NO_X Annual source or the designated representative of a CSAPR NO_X Annual source shall also apply to the owners and operators of such source and of the CSAPR NO_X Annual units at the source.

(2) Any provision of the CSAPR NO_X Annual Trading Program that applies to a CSAPR NO_X Annual unit or the designated representative of a CSAPR NO_X Annual unit shall also apply to the owners and operators of such unit.

(g) Effect on other authorities.

No provision of the CSAPR NO_X Annual Trading Program or exemption under 40 CFR 97.405 shall be construed as exempting or excluding the owners and operators, and the designated representative, of a CSAPR NO_X Annual source or CSAPR NO_X Annual unit from compliance with any other provision of the applicable, approved state implementation plan, a federally enforceable permit, or the Clean Air Act.

(h) Allowance allocations for existing units.

(1) In accordance with 40 CFR 97.411(a)(1), CSAPR NO_X Annual allowances for existing units are allocated, for the control periods in 2015 and each year thereafter, as provided in a notice of data availability issued by the Administrator.

(2) As of the date of issuance of this permit, the current CSAPR NO_X annual allowances for CSAPR subject units at LG&E, Mill Creek are summarized in the following table:[155]

CSAPR NO_X Annual Allocations						
	2015 (tons)	2016 (tons)	2017 (tons)	2018 (tons)	2019 (tons)	2020 (tons)
Unit 1	1,574	1,574	1,427	1,427	1,427	1,427
Unit 2	1,699	1,699	1,540	1,540	1,540	1,540
Unit 3	2,351	2,351	2,131	2,131	2,131	2,131
Unit 4	2,766	2,766	2,508	2,508	2,508	2,508

III. CSAPR NOX Ozone Season Group 2 Trading Program Requirements (40 CFR 97, Subpart EEEEE)

(a) Designated representative requirements.

The owners and operators shall comply with the requirement to have a designated representative, and may have an alternate designated representative, in accordance with 40 CFR 97.813 through 97.818.

(b) Emissions monitoring, reporting, and recordkeeping requirements.

(1) The owners and operators, and the designated representative, of each CSAPR NOX Ozone Season Group 2 source and each CSAPR NOX Ozone Season Group 2 unit at the source shall comply with the monitoring, reporting, and recordkeeping requirements of 40 CFR 97.830 (general requirements, including installation, certification, and data accounting, compliance deadlines, reporting data, prohibitions, and long-term cold storage), 97.831 (initial monitoring system certification and recertification procedures), 97.832 (monitoring system out-of-control periods), 97.833 (notifications concerning monitoring), 97.834 (recordkeeping and

[155] According to notice of data availability issued in Federal Register 79 FR 71674, December 3, 2014. . This table is included for informational purposes and is subject to change. These allocations can be bought, sold, or traded as necessary.

reporting, including monitoring plans, certification applications, quarterly reports, and compliance certification), and 97.835 (petitions for alternatives to monitoring, recordkeeping, or reporting requirements).

(2) The emissions data determined in accordance with 40 CFR 97.830 through 97.835 shall be used to calculate allocations of CSAPR NOX Ozone Season Group 2 allowances under 40 CFR 97.811(a)(2) and (b) and 97.812 and to determine compliance with the CSAPR NOX Ozone Season Group 2 emissions limitation and assurance provisions under paragraph (c) below, provided that, for each monitoring location from which mass emissions are reported, the mass emissions amount used in calculating such allocations and determining such compliance shall be the mass emissions amount for the monitoring location determined in accordance with 40 CFR 97.830 through 97.835 and rounded to the nearest ton, with any fraction of a ton less than 0.50 being deemed to be zero.

(c) NO_X emissions requirements.

(1) CSAPR NOX Ozone Season Group 2 emissions limitation.

(i). As of the allowance transfer deadline for a control period in a given year, the owners and operators of each CSAPR NOX Ozone Season Group 2 source and each CSAPR NOX Ozone Season Group 2 unit at the source shall hold, in the source's compliance account, CSAPR NOX Ozone Season Group 2 allowances available for deduction for such control period under 40 CFR 97.824(a) in an amount not less than the tons of total NO_X emissions for such control period from all CSAPR NOX Ozone Season Group 2 units at the source.

(ii). If total NO_X emissions during a control period in a given year from the CSAPR NOX Ozone Season Group 2 units at a CSAPR NOX Ozone Season Group 2 source are in excess of the CSAPR NOX Ozone Season Group 2 emissions limitation set forth in paragraph (c)(1)(i) above, then:

(A). The owners and operators of the source and each CSAPR NOX Ozone Season Group 2 unit at the source shall hold the CSAPR NOX Ozone Season Group 2 allowances required for deduction under 40 CFR 97.824(d); and

(B). The owners and operators of the source and each CSAPR NOX Ozone Season Group 2 unit at the source shall pay any fine, penalty, or assessment or comply with any other remedy imposed, for the same violations, under the Clean Air Act, and each ton of such excess emissions and each day of such control period shall constitute a separate violation of 40 CFR part 97, subpart EEEEE and the Clean Air Act.

(2) CSAPR NOX Ozone Season Group 2 assurance provisions.

(i). If total NO_X emissions during a control period in a given year from all CSAPR NOX Ozone Season Group 2 units at CSAPR NOX Ozone Season Group 2 sources in the state exceed the state assurance level, then the owners and operators of such sources and units in each group of one or more sources and units having a common designated representative for such control period, where the common designated representative's share of such NO_X emissions during such control period exceeds the common designated representative's assurance level for the state and such control period, shall hold (in the assurance account established for the owners and operators of such group) CSAPR NOX Ozone Season Group 2 allowances available for deduction for such control period under 40 CFR 97.825(a) in an amount equal to two times the product (rounded to the nearest whole number), as determined by the Administrator in accordance with 40 CFR 97.825(b), of multiplying—

(A). The quotient of the amount by which the common designated representative's share of such NO_X emissions exceeds the common designated representative's assurance level divided by the sum of the amounts, determined for all common designated representatives for such sources and units in the state for such control period, by which each common designated representative's share of such NO_X emissions exceeds the respective common designated representative's assurance level; and

(B). The amount by which total NO_X emissions from all CSAPR NOX Ozone Season Group 2 units at CSAPR NOX Ozone Season Group 2 sources in the state for such control period exceed the state assurance level.

(ii). The owners and operators shall hold the CSAPR NOX Ozone Season Group 2 allowances required under paragraph (c)(2)(i) above, as of midnight of November 1 (if it is a business day), or midnight of the first business day thereafter (if November 1 is not a business day), immediately after such control period.

(iii). Total NO_X emissions from all CSAPR NOX Ozone Season Group 2 units at CSAPR NOX Ozone Season Group 2 sources in the state during a control period in a given year exceed the state assurance level if such total NO_X emissions exceed the sum, for such control period, of the State NOX Ozone Season Group 2 trading budget under 40 CFR 97.810(a) and the state's variability limit under 40 CFR 97.810(b).

(iv). It shall not be a violation of 40 CFR part 97, subpart EEEEE or of the Clean Air Act if total NO_X emissions from all CSAPR NOX Ozone Season Group 2 units at CSAPR NOX Ozone Season Group 2 sources in the state during a control period exceed the state assurance level or if a common designated representative's share of total NO_X emissions from the CSAPR NOX Ozone Season Group 2 units at CSAPR NOX Ozone Season Group 2 sources in the state during a control period exceeds the common designated representative's assurance level.

(v). To the extent the owners and operators fail to hold CSAPR NOX Ozone Season Group 2 allowances for a control period in a given year in accordance with paragraphs (c)(2)(i) through (iii) above,

(A). The owners and operators shall pay any fine, penalty, or assessment or comply with any other remedy imposed under the Clean Air Act; and

(B). Each CSAPR NOX Ozone Season Group 2 allowance that the owners and operators fail to hold for such control period in accordance with paragraphs (c)(2)(i) through (iii) above and each day of such control period shall constitute a separate violation of 40 CFR part 97, subpart EEEEE and the Clean Air Act.

(3) Compliance periods.

(i). A CSAPR NOX Ozone Season Group 2 unit shall be subject to the requirements under paragraph (c)(1) above for the control period starting on the later of May 1, 2015 or the deadline for meeting the unit's monitor certification requirements under 40 CFR 97.830(b) and for each control period thereafter.

(ii). A CSAPR NOX Ozone Season Group 2 unit shall be subject to the requirements under paragraph (c)(2) above for the control period starting on the later of May 1, 2017 or the deadline for meeting the unit's monitor certification requirements under 40 CFR 97.830(b) and for each control period thereafter.

(4) Vintage of allowances held for compliance.

(i). A CSAPR NOX Ozone Season Group 2 allowance held for compliance with the requirements under paragraph (c)(1)(i) above for a control period in a given year must be a CSAPR NOX Ozone Season Group 2 allowance that was allocated for such control period or a control period in a prior year.

(ii). A CSAPR NOX Ozone Season Group 2 allowance held for compliance with the requirements under paragraphs (c)(1)(ii)(A) and (2)(i) through (iii) above for a control period in a given year must be a CSAPR NOX Ozone Season Group 2 allowance that was allocated for a control period in a prior year or the control period in the given year or in the immediately following year.

(5) Allowance Management System requirements. Each CSAPR NOX Ozone Season Group 2 allowance shall be held in, deducted from, or transferred into, out of, or between Allowance Management System accounts in accordance with 40 CFR part 97, subpart EEEEE.

(6) Limited authorization. A CSAPR NOX Ozone Season Group 2 allowance is a limited authorization to emit one ton of NO_X during the control period in one year. Such authorization is limited in its use and duration as follows:

(i). Such authorization shall only be used in accordance with the CSAPR NOX Ozone Season Group 2 Trading Program; and

(ii). Notwithstanding any other provision of 40 CFR part 97, subpart EEEEE, the Administrator has the authority to terminate or limit the use and duration of such authorization to the extent the Administrator determines is necessary or appropriate to implement any provision of the Clean Air Act.

(7) Property right. A CSAPR NOX Ozone Season Group 2 allowance does not constitute a property right.

(d) Title V permit revision requirements.

(1) No title V permit revision shall be required for any allocation, holding, deduction, or transfer of CSAPR NOX Ozone Season Group 2 allowances in accordance with 40 CFR part 97, subpart EEEEE.

(2) This permit incorporates the CSAPR emissions monitoring, recordkeeping and reporting requirements pursuant to 40 CFR 97.830 through 97.835, and the requirements for a continuous emission monitoring system (pursuant to 40 CFR part 75, subparts B and H), an excepted monitoring system (pursuant to 40 CFR part 75, appendices D and E), a low mass emissions excepted monitoring methodology (pursuant to 40 CFR 75.19), and an

alternative monitoring system (pursuant to 40 CFR part 75, subpart E). Therefore, the Description of CSAPR Monitoring Provisions table for units identified in this permit may be added to, or changed, in this title V permit using minor permit modification procedures in accordance with 40 CFR 97.806(d)(2) and 70.7(e)(2)(i)(B) or 71.7(e)(1)(i)(B).

(e) Additional recordkeeping and reporting requirements.

(1) Unless otherwise provided, the owners and operators of each CSAPR NOX Ozone Season Group 2 source and each CSAPR NOX Ozone Season Group 2 unit at the source shall keep on site at the source each of the following documents (in hardcopy or electronic format) for a period of 5 years from the date the document is created. This period may be extended for cause, at any time before the end of 5 years, in writing by the Administrator.

(i). The certificate of representation under 40 CFR 97.816 for the designated representative for the source and each CSAPR NOX Ozone Season Group 2 unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation; provided that the certificate and documents shall be retained on site at the source beyond such 5-year period until such certificate of representation and documents are superseded because of the submission of a new certificate of representation under 40 CFR 97.816 changing the designated representative.

(ii). All emissions monitoring information, in accordance with 40 CFR part 97, subpart EEEEE.

(iii). Copies of all reports, compliance certifications, and other submissions and all records made or required under, or to demonstrate compliance with the requirements of, the CSAPR NOX Ozone Season Group 2 Trading Program.

(2) The designated representative of a CSAPR NOX Ozone Season Group 2 source and each CSAPR NOX Ozone Season Group 2 unit at the source shall make all submissions required under the CSAPR NOX Ozone Season Group 2 Trading Program, except as provided in 40 CFR 97.818. This requirement does not change, create an exemption from, or otherwise affect the responsible official submission requirements under a title V operating permit program in 40 CFR parts 70 and 71.

(f) Liability.

(1) Any provision of the CSAPR NOX Ozone Season Group 2 Trading Program that applies to a CSAPR NOX Ozone Season Group 2 source or

the designated representative of a CSAPR NOX Ozone Season Group 2 source shall also apply to the owners and operators of such source and of the CSAPR NOX Ozone Season Group 2 units at the source.

(2) Any provision of the CSAPR NOX Ozone Season Group 2 Trading Program that applies to a CSAPR NOX Ozone Season Group 2 unit or the designated representative of a CSAPR NOX Ozone Season Group 2 unit shall also apply to the owners and operators of such unit.

(g) Effect on other authorities.

No provision of the CSAPR NOX Ozone Season Group 2 Trading Program or exemption under 40 CFR 97.805 shall be construed as exempting or excluding the owners and operators, and the designated representative, of a CSAPR NOX Ozone Season Group 2 source or CSAPR NOX Ozone Season Group 2 unit from compliance with any other provision of the applicable, approved state implementation plan, a federally enforceable permit, or the Clean Air Act.

(h) Allowance allocations for existing units.

(1) In accordance with 40 CFR 97.811(a)(1), CSAPR NOX Ozone Season Group 2 allowances for existing units are allocated, for the control periods in 2015 and each year thereafter, as provided in a notice of data availability issued by the Administrator.

(2) Current CSAPR NOX Ozone Season Group 2 allowances for CSAPR subject units at LG&E, Mill Creek are summarized in the following table:[156]

CSAPR NOX Ozone Season Group 2 Allocations						
	2015 (tons)	2016 (tons)	2017 (tons)	2018 (tons)	2019 (tons)	2020 (tons)
Unit 1	674	674	405	405	405	405
Unit 2	731	731	445	445	445	445
Unit 3	1,098	1,098	562	562	562	562
Unit 4	1,282	1,282	641	641	641	641

IV. CSAPR SO_2 Group 1 Trading Program requirements (40 CFR 97, Subpart CCCCC)

(a) Designated representative requirements.

[156] According to notice of data availability December 3, 2014 and September 7, 2016. This table is included for informational purposes and is subject to change. These allocations can be bought, sold, or traded as necessary.

The owners and operators shall comply with the requirement to have a designated representative, and may have an alternate designated representative, in accordance with 40 CFR 97.613 through 97.618.

(b) Emissions monitoring, reporting, and recordkeeping requirements.

(1) The owners and operators, and the designated representative, of each CSAPR SO_2 Group 1 source and each CSAPR SO_2 Group 1 unit at the source shall comply with the monitoring, reporting, and recordkeeping requirements of 40 CFR 97.630 (general requirements, including installation, certification, and data accounting, compliance deadlines, reporting data, prohibitions, and long-term cold storage), 97.631 (initial monitoring system certification and recertification procedures), 97.632 (monitoring system out-of-control periods), 97.633 (notifications concerning monitoring), 97.634 (recordkeeping and reporting, including monitoring plans, certification applications, quarterly reports, and compliance certification), and 97.635 (petitions for alternatives to monitoring, recordkeeping, or reporting requirements).

(2) The emissions data determined in accordance with 40 CFR 97.630 through 97.635 shall be used to calculate allocations of CSAPR SO_2 Group 1 allowances under 40 CFR 97.611(a)(2) and (b) and 97.612 and to determine compliance with the CSAPR SO_2 Group 1 emissions limitation and assurance provisions under paragraph (c) below, provided that, for each monitoring location from which mass emissions are reported, the mass emissions amount used in calculating such allocations and determining such compliance shall be the mass emissions amount for the monitoring location determined in accordance with 40 CFR 97.630 through 97.635 and rounded to the nearest ton, with any fraction of a ton less than 0.50 being deemed to be zero.

(c) SO_2 emissions requirements.

(1) CSAPR SO_2 Group 1 emissions limitation.

(i). As of the allowance transfer deadline for a control period in a given year, the owners and operators of each CSAPR SO_2 Group 1 source and each CSAPR SO2 Group 1 unit at the source shall hold, in the source's compliance account, CSAPR SO_2 Group 1 allowances available for deduction for such control period under 40 CFR 97.624(a) in an amount not less than the tons of total SO_2 emissions for such control period from all CSAPR SO_2 Group 1 units at the source.

(ii). If total SO_2 emissions during a control period in a given year from the CSAPR SO_2 Group 1 units at a CSAPR SO_2 Group 1 source are in excess of the CSAPR SO_2 Group 1 emissions limitation set forth in paragraph (c)(1)(i) above, then:

(A). The owners and operators of the source and each CSAPR SO_2 Group 1 unit at the source shall hold the CSAPR SO_2 Group 1 allowances required for deduction under 40 CFR 97.624(d); and

(B). The owners and operators of the source and each CSAPR SO_2 Group 1 unit at the source shall pay any fine, penalty, or assessment or comply with any other remedy imposed, for the same violations, under the Clean Air Act, and each ton of such excess emissions and each day of such control period shall constitute a separate violation 40 CFR part 97, subpart CCCCC and the Clean Air Act.

(2) CSAPR SO_2 Group 1 assurance provisions.

(i). If total SO_2 emissions during a control period in a given year from all CSAPR SO_2 Group 1 units at CSAPR SO_2 Group 1 sources in the state exceed the state assurance level, then the owners and operators of such sources and units in each group of one or more sources and units having a common designated representative for such control period, where the common designated representative's share of such SO_2 emissions during such control period exceeds the common designated representative's assurance level for the state and such control period, shall hold (in the assurance account established for the owners and operators of such group) CSAPR SO_2 Group 1 allowances available for deduction for such control period under 40 CFR 97.625(a) in an amount equal to two times the product (rounded to the nearest whole number), as determined by the Administrator in accordance with 40 CFR 97.625(b), of multiplying—

(A). The quotient of the amount by which the common designated representative's share of such SO_2 emissions exceeds the common designated representative's assurance level divided by the sum of the amounts, determined for all common designated representatives for such sources and units in the state for such control period, by which each common designated representative's share of such SO_2 emissions exceeds the respective common designated representative's assurance level; and

(B). The amount by which total SO_2 emissions from all CSAPR SO_2 Group 1 units at CSAPR SO_2 Group 1 sources in the state for such control period exceed the state assurance level.

(ii). The owners and operators shall hold the CSAPR SO_2 Group 1 allowances required under paragraph (c)(2)(i) above, as of midnight of November 1 (if it is a business day), or midnight of the first business day thereafter (if November 1 is not a business day), immediately after such control period.

(iii). Total SO_2 emissions from all CSAPR SO_2 Group 1 units at CSAPR SO_2 Group 1 sources in the state during a control period in a given year exceed the state assurance level if such total SO_2 emissions exceed the sum, for such control period, of the state SO_2 Group 1 trading budget under 40 CFR 97.610(a) and the state's variability limit under 40 CFR 97.610(b).

(iv). It shall not be a violation of 40 CFR part 97, subpart CCCCC or of the Clean Air Act if total SO_2 emissions from all CSAPR SO_2 Group 1 units at CSAPR SO_2 Group 1 sources in the state during a control period exceed the state assurance level or if a common designated representative's share of total SO_2 emissions from the CSAPR SO_2 Group 1 units at CSAPR SO_2 Group 1 sources in the state during a control period exceeds the common designated representative's assurance level.

(v). To the extent the owners and operators fail to hold CSAPR SO_2 Group 1 allowances for a control period in a given year in accordance with paragraphs (c)(2)(i) through (iii) above,

(A). The owners and operators shall pay any fine, penalty, or assessment or comply with any other remedy imposed under the Clean Air Act; and

(B). Each CSAPR SO_2 Group 1 allowance that the owners and operators fail to hold for such control period in accordance with paragraphs (c)(2)(i) through (iii) above and each day of such control period shall constitute a separate violation of 40 CFR part 97, subpart CCCCC and the Clean Air Act.

(3) Compliance periods.

(i). A CSAPR SO_2 Group 1 unit shall be subject to the requirements under paragraph (c)(1) above for the control period starting on the later of January 1, 2015 or the deadline for meeting the unit's monitor certification requirements under 40 CFR 97.630(b) and for each control period thereafter.

(ii). A CSAPR SO_2 Group 1 unit shall be subject to the requirements under paragraph (c)(2) above for the control period starting on the later of January 1, 2017 or the deadline for meeting the unit's monitor certification requirements under 40 CFR 97.630(b) and for each control period thereafter.

(4) Vintage of allowances held for compliance.

(i). A CSAPR SO_2 Group 1 allowance held for compliance with the requirements under paragraph (c)(1)(i) above for a control period in a given year must be a CSAPR SO_2 Group 1 allowance that was allocated for such control period or a control period in a prior year.

(ii). A CSAPR SO_2 Group 1 allowance held for compliance with the requirements under paragraphs (c)(1)(ii)(A) and (2)(i) through (iii) above for a control period in a given year must be a CSAPR SO_2 Group 1 allowance that was allocated for a control period in a prior year or the control period in the given year or in the immediately following year.

(5) Allowance Management System requirements. Each CSAPR SO_2 Group 1 allowance shall be held in, deducted from, or transferred into, out of, or between Allowance Management System accounts in accordance with 40 CFR part 97, subpart CCCCC.

(6) Limited authorization. A CSAPR SO_2 Group 1 allowance is a limited authorization to emit one ton of SO_2 during the control period in one year. Such authorization is limited in its use and duration as follows:

(i). Such authorization shall only be used in accordance with the CSAPR SO_2 Group 1 Trading Program; and

(ii). Notwithstanding any other provision of 40 CFR part 97, subpart CCCCC, the Administrator has the authority to terminate or limit the use and duration of such authorization to the extent the Administrator determines is necessary or appropriate to implement any provision of the Clean Air Act.

(7) Property right. A CSAPR SO_2 Group 1 allowance does not constitute a property right.

(d) Title V permit revision requirements.

(1) No title V permit revision shall be required for any allocation, holding, deduction, or transfer of CSAPR SO_2 Group 1 allowances in accordance with 40 CFR part 97, subpart CCCCC.

(2) This permit incorporates the CSAPR emissions monitoring, recordkeeping and reporting requirements pursuant to 40 CFR 97.630 through 97.635, and the requirements for a continuous emission monitoring system (pursuant to 40 CFR part 75, subparts B and H), an excepted monitoring system (pursuant to 40 CFR part 75, appendices D and E), a low mass emissions excepted monitoring methodology (pursuant to 40 CFR part 75.19), and an alternative monitoring system (pursuant to 40 CFR part 75, subpart E), Therefore, the Description of CSAPR Monitoring Provisions table for units identified in this permit may be added to, or changed, in this title V permit using minor permit modification procedures in accordance with 40 CFR 97.606(d)(2) and 70.7(e)(2)(i)(B) or 71.7(e)(1)(i)(B).

(e) Additional recordkeeping and reporting requirements.

(1) Unless otherwise provided, the owners and operators of each CSAPR SO_2 Group 1 source and each CSAPR SO_2 Group 1 unit at the source shall keep on site at the source each of the following documents (in hardcopy or electronic format) for a period of 5 years from the date the document is created. This period may be extended for cause, at any time before the end of 5 years, in writing by the Administrator.

(i). The certificate of representation under 40 CFR 97.616 for the designated representative for the source and each CSAPR SO_2 Group 1 unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation; provided that the certificate and documents shall be retained on site at the source beyond such 5-year period until such certificate of representation and documents are superseded because of the submission of a new certificate of representation under 40 CFR 97.616 changing the designated representative.

(ii). All emissions monitoring information, in accordance with 40 CFR part 97, subpart CCCCC.

(iii). Copies of all reports, compliance certifications, and other submissions and all records made or required under, or to demonstrate compliance with the requirements of, the CSAPR SO_2 Group 1 Trading Program.

(2) The designated representative of a CSAPR SO_2 Group 1 source and each CSAPR SO_2 Group 1 unit at the source shall make all submissions required under the CSAPR SO_2 Group 1 Trading Program, except as provided in 40

CFR 97.618. This requirement does not change, create an exemption from, or otherwise affect the responsible official submission requirements under a title V operating permit program in 40 CFR parts 70 and 71.

(f) Liability.

(1) Any provision of the CSAPR SO_2 Group 1 Trading Program that applies to a CSAPR SO_2 Group 1 source or the designated representative of a CSAPR SO_2 Group 1 source shall also apply to the owners and operators of such source and of the CSAPR SO_2 Group 1 units at the source.

(2) Any provision of the CSAPR SO_2 Group 1 Trading Program that applies to a CSAPR SO_2 Group 1 unit or the designated representative of a CSAPR SO_2 Group 1 unit shall also apply to the owners and operators of such unit.

(g) Effect on other authorities.

No provision of the CSAPR SO_2 Group 1 Trading Program or exemption under 40 CFR 97.605 shall be construed as exempting or excluding the owners and operators, and the designated representative, of a CSAPR SO_2 Group 1 source or CSAPR SO_2 Group 1 unit from compliance with any other provision of the applicable, approved state implementation plan, a federally enforceable permit, or the Clean Air Act.

(h) Allowance allocations for existing units.

(1) In accordance with 40 CFR 97.611(a)(1), CSAPR SO_2 Group 1 allowances for existing units are allocated, for the control periods in 2015 and each year thereafter, as provided in a notice of data availability issued by the Administrator.

(2) Current CSAPR SO_2 Group 1 allowances for CSAPR subject units at LG&E, Mill Creek are summarized in the following table:[157]

CSAPR SO_2 Group 1 Allocations						
	2015 (tons)	2016 (tons)	2017 (tons)	2018 (tons)	2019 (tons)	2020 (tons)
Unit 1	4,531	4,595	1,950	1,950	1,950	1,950
Unit 2	4,892	4,961	2,105	2,105	2,105	2,105
Unit 3	6,769	6,864	2,912	2,912	2,912	2,912
Unit 4	7,964	8,076	3,427	3,427	3,427	3,427

[157] According to notice of data availability issued in Federal Register 79 FR 71674, December 3, 2014. This table is included for informational purposes and is subject to change. These allocations can be bought, sold, or traded as necessary.

Attachment H – Clean Air Interstate Rule (CAIR)

1. Statement of Basis

Statutory and Regulatory Authorities: CAIR requirements are incorporated into this Title V permit pursuant to the CAIR Kentucky SIP approved on 10/4/2007. The CAIR Kentucky SIP establishes State budgets for SO2 and NOx in accordance with 40 CFR 96, CAIR NO_X Annual Trading Program, CAIR NO_X Ozone season trading program, and CAIR SO_2 Trading Program. On September 7, 2016, the EPA finalized an update to the Cross-State Air Pollution Rule (CSAPR) for the 2008 ozone National Ambient Air Quality Standards (NAAQS) by issuing the final CSAPR Update. CSAPR Phase I implementation is now in place and replaces requirements under EPA's 2005 Clean Air Interstate Rule.

2. CAIR Application

The CAIR application for four coal-fired EGUs (U1, U2, U3, and U4) was received on June 29, 2007. Requirements contained in that application are hereby incorporated into and made part of this Title V Permit. Pursuant to Regulation 2.16, Section 4.1.3, the source shall operate in compliance with those requirements. On September 7, 2016, the EPA finalized an update to the Cross-State Air Pollution Rule (CSAPR) for the 2008 ozone National Ambient Air Quality Standards (NAAQS) by issuing the final CSAPR Update. CSAPR Phase I implementation is now in place and replaces requirements under EPA's 2005 Clean Air Interstate Rule.

3. Comments, notes, justifications regarding permit decisions and changes made to the permit application forms during the review process, and any additional requirements or conditions.

Affected units are four (4) coal-fired boilers, U1, U2, U3, and U4, with a maximum rating of 3,085 MMBtu/hr, 3,085 MMBtu/hr, 4,204 MMBtu/hr, and 5,025 MMBtu/hr respectively. Each unit has a capacity to generate 25 MW or more of electricity, which is offered for sale.

4. Summary of Actions

The CAIR requirements are being incorporated as part of the revised Title V permit for this source. Public, affected state and US EPA review shall follow procedures.

A December 2008 court decision kept the requirements of CAIR in place temporarily but directed EPA to issue a new rule to implement Clean Air Act requirements concerning the transport of air pollution across state boundaries. On July 6, 2011, the U.S. EPA finalized the Cross-State Air Pollution Rule (CSAPR). On December 30, 2011, CSAPR was stayed prior to implementation. On April 29, 2014, the U.S. Supreme Court issued an opinion reversing an August 21, 2012 D.C. Circuit decision that had vacated CSAPR. Following the remand of the case to the D.C. Circuit, EPA requested that the court lift the CSAPR stay and toll the CSAPR compliance deadlines by three years. On October 23, 2014, the D.C. Circuit granted EPA's request. On September 7, 2016, the EPA finalized an update to the Cross-State Air Pollution Rule (CSAPR) for the 2008 ozone

National Ambient Air Quality Standards (NAAQS) by issuing the final CSAPR Update. CSAPR Phase I implementation is now in place and replaces requirements under EPA's 2005 Clean Air Interstate Rule.

Attachment I - Control Device Efficiencies and Determination Methods

Unit ID	Control ID	Description	Control Efficiency	Control Efficiency Determination Methods [1, 2]
U1	C1	ESP	N/A	Annual test used for compliance demonstration
	C2	FGD (old)	N/A	CEMS used for compliance demonstration
	C3	dust collector	90%	Option 1.
	C26	PAC/Sorbent/PJFF/Liquid Additives	TBD	Option 3. Stack test required by construction permit
	C27	FGD (new)	N/A	CEMS used for compliance demonstration
U2	C4	ESP	N/A	Annual test used for compliance demonstration
	C5	FGD (old)	N/A	CEMS used for compliance demonstration
	C6	dust collector	90%	Option 1.
	C28	PAC/Sorbent/PJFF/Liquid Additives	TBD	Option 3. Stack test required by construction permit
U3	C7	ESP	N/A	Annual test used for compliance demonstration
	C8	FGD (old)	N/A	CEMS used for compliance demonstration
	C9	dust collector	90%	Option 1.
	C22	SCR	N/A	CEMS used for compliance demonstration
	C29	PAC/Sorbent/PJFF/Liquid Additives	TBD	Option 3. Stack test required by construction permit
	C39	FGD (new)	N/A	CEMS used for compliance demonstration
U4	C10	ESP	N/A	Annual test used for compliance demonstration
	C11	FGD (old)	N/A	CEMS used for compliance demonstration
	C12	dust collector	90%	Option 1.
	C23	SCR	N/A	CEMS used for compliance demonstration
	C30	PAC Sorbent PJFF Liquid Additives	97.7% 99.4% 99.8% TBD	Option 3. Stack test conducted Jan. 20 through 22, Feb. 5 and 6, 2015.
	C31	FGD (new)	N/A	CEMS used for compliance demonstration
U8	C15	Baghouse	95%	Option 1.
	C16	Baghouse	95%	Option 1.
	C24	Baghouse	95%	Option 1.
	C25	Baghouse	95%	Option 1.
	C37	Filter	95%	Option 1.
	C38	Filter	95%	Option 1.
U9	C19	Baghouse	95%	Option 1.
	C20	Baghouse	95%	Option 1.
	C21	Baghouse	95%	Option 1.
U16	C32	Bin vent filters	99%	Option 2, received 9/13/2013
U17	C33	Bin vent filters	99%	Option 2, received 9/13/2013
U18	C34	Bin vent filters	99%	Option 2, received 9/13/2013
U20	C36	Baghouse	N/A	Processing baghouse

Unit ID	Control ID	Description	Control Efficiency	Control Efficiency Determination Methods [1, 2]
U15, 22		Watering	70%	Option 1. Watering unpaved roads once every two hours.

Note:

1. Options for control efficiency determination:
   Option 1: Use District pre-approved control efficiency
   Option 2: Submit a signature guarantee from the control device manufacture stating the control device efficiency
   Option 3: Perform stack test. See Note 3 for general testing requirements.

2. Until the District receives a signature guarantee from the control device manufacturer stating the control device efficiency is higher (Option 2), or an approved stack test (Option 3), the pre-approved efficiency (Option 1) will be used in all calculations to demonstrate compliance with applicable standards and calculations for emission inventory.

3. General Testing Requirements (Regulation 2.16, section 4.1.9.1)

   Plantwide the owner or operator shall retest all control devices within ten (10) years since the most recent District accepted performance test or within 180 days after the effective date of the permit if no previous test has been performed. For equipment which has been tested but not within ten years prior to the effective date of this permit the Company may submit within 90 days of the effective date of this permit, contingent on approval by the District, a schedule which shall at a minimum propose testing for all affected equipment within this permit cycle. Thereafter the Company shall retest each affected device at least once every 10 years. Devices of adequately similar design and filter media may be represented by a common performance test contingent upon review and approval by the District of the testing protocol. In lieu of the control efficiency testing, unless required by a Federal Regulation, the owner or operator may submit a signature guarantee from the control device manufacture stating the control device efficiency.

   The owner or operator shall use the most recent District accepted performance test results to demonstrate compliance with the emission limits and in the annual emission inventory reporting.

   If performance testing is not completed by the required date, then the company shall calculate emissions using expired test result data or methods such as EPA approved emission factors and guidance documents such as EIIP and AP-42 or other methods upon written approval by the District, whichever results in the greater (more conservative) emissions.

   The owner or operator shall construct all equipment in such a manner that the following testing requirements can be performed.

   i. The owner or operator shall perform an EPA Reference Method (or equivalent methods that approved by the District) performance test. The test shall be performed at 90% or higher of maximum capacity, or allowable/permitted capacity, or at a level of capacity which results in the greatest emissions and is representative of the operations. Failure to perform the test, at maximum capacity, allowable/permitted capacity, or at a level of capacity which resulted in the greatest emissions, may necessitate a re-test or necessitate a revision of the allowable/permitted capacity of the process equipment depending upon the difference between the testing results and the limit.

ii. The owner or operator shall perform a capture efficiency test using EPA guidelines. In lieu of performing a capture efficiency test, the owner or operator may submit a reasonable estimate of capture efficiency with thorough justification subject to approval by the District.

iii. The owner or operator shall submit written compliance test plans (protocol) for the control efficiency and capture efficiency. They shall include the EPA test methods that will be used for compliance testing, the process operating parameters that will be monitored during the performance test, and the control device performance indicators (e.g. pressure drop, minimum combustion chamber temperature) that will be monitored during the performance test. The compliance test plans shall be furnished to the District at least 30 days prior to the actual date of the performance test. Attached to the permit is a Protocol Checklist for Performance Test for the information to be submitted in the protocol.

iv. The owner or operator shall be responsible for obtaining and analyzing audit samples when the EPA Reference Method is used to analyze samples to demonstrate compliance with the source's emission regulation. The audit samples shall be available for verification by the District during the onsite testing.

v. The owner or operator shall provide the District at least 10 days prior notice of any performance test to afford the District the opportunity to have an observer present.

vi. The owner or operator shall furnish the District with a written report of the results of the performance test within 60 days following the actual date of completion of the performance test.

vii. The owner or operator shall provide written notification to the District of the actual date of initial startup (only required for new equipment). The written notification shall be postmarked within 15 days after the effective date of the permit.

Attachment J - Determination of Benchmark Ambient Concentration (BAC)

Determination of Benchmark Ambient Concentration (BAC) **Category No. _____**

TAC ____ **CAS No.** __________-______-____

____ **Mol. Wt.** ________

BAC_C = _______ µg/m³ Annual **BAC_{NC} = ________ µg/m³ ________ Averaging Period**

De Minimis_________ lb/hour; _________ lb/___________; ___________ lb/year

I. Carcinogen Risk - BAC_C [Annual Averaging Period] Carcinogen . . . . ☐ yes ☐ no

1. ☐ IRIS ☐ no 10^{-6} risk = ___________ µg/m³ URE __________ (µg/m³)$^{-1}$ ___-___-___
2. ☐ Cal ☐ no 10^{-6} risk = ___________ µg/m³ IUR __________ (µg/m³)$^{-1}$ ___-___-___
3. ☐ MI ☐ no 10^{-6} risk = ___________ µg/m³ ___-___-___
4. ☐ NTP Part A ☐ yes ☐ no Part B ☐ yes ☐ no
5. ☐ IARC Group 1 ☐ yes ☐ no Group 2A ☐ yes ☐ no Group 2B ☐ yes ☐ no
6. ☐ ATSDR ☐ no
7. ☐ Sec. 3.3.4 method _______________☐ no 10^{-6} risk = _________ µg/m³ ___-___-___
8. ☐ Default 0.0004 µg/m³

II. Chronic Noncancer Risk - BAC_{NC} [Averaging Period as Specified]

1. ☐ IRIS ☐ no RfC = ___________ µg/m³ Annual ___-___-___
2. ☐ Cal ☐ no REL = ___________ µg/m³ Annual ___-___-___
3. ☐ IRIS[1] ☐ no RfD = _______µg/kg/day ⊗ 70/20 =______µg/m³ Annual ___-___-___
4. ☐ MI ☐ no ITSL = ___________ µg/m³_________ Averaging Period ___-___-___
5. ☐ TLV ☐ NIOSH _________ µg/m³ ⊗ 0.01 = ________ µg/m³ 8-Hr ___-___-___
6. ☐ RTECS[1] _______ ____________ = ________ µg/m³ Annual
7. ☐ Default 0.04 µg/m³ Annual

III. De Minimis

1. ☐ Carcinogen (BAC_C) _________ µg/m³ ⊗ 0.54 = _________ lb/hour
   (BAC_C) _________ µg/m³ ⊗ 480 = __________ lb/year
2. ☐ Chronic Noncancer Risk ___________ Averaging Period
   (BAC_{NC}) _________ µg/m³ ⊗ _______ = _________ lb/hour
   (BAC_{NC}) _________ µg/m³ ⊗ _______ = _________ lb/_________
   _________ lb/_________ ⊗ _______ _______ = _________ lb/year

[1] To use data based upon an oral route of exposure, the District must make an affirmative determination that data are not available to indicate that oral-route to inhalation-route extrapolation is inappropriate.

Prepared by ____ ___-___-___

Attachment K – Compliance Assurance Monitoring (CAM) Plan

Louisville Gas and Electric/Mill Creek Generating Station

Introduction

CAM applies at Title V major sources that use control devices to achieve compliance with an applicable limit or standard and have potential pre-control emissions greater than or equal to 100% of the major source trigger for the pollutant.

Louisville Gas and Electric's Mill Creek Generating Station utilizes the following control devices that will become subject to the CAM requirements as part of the Title V renewal process:

- Emission Unit E-1 (Unit 1 dry-bottom tangentially-fired boiler) employs an electrostatic precipitator (ESP) for particulate matter (PM) control; and a wet lime flue gas desulfurization system (WFGD) for sulfur dioxide (SO_2) control.
- Emission Unit E-3 (Unit 2 dry-bottom tangentially-fired boiler) employs an ESP for PM control and a WFGD for SO_2 control.
- Emission Unit E-5 (Unit 3 wall-fired boiler) employs an ESP for PM control, a WFGD for SO_2 control, and a selective catalytic reduction (SCR) for nitrogen oxide (NOx) control.
- Emission Unit E-7 (Unit 4 wall-fired boiler) employs an ESP for PM control, a WFGD for SO_2 control, and an SCR for NOx control.

The CAM Plan will have three parts, and they are as follows:
(1) Emission Units E-1, E-3, E-5, and E-7 will have a CAM plan for PM.
(2) Emission Units E-1, E-3, E-5, and E-7 will have a CAM plan for SO2.
(3) Emission Units E-5, and E-7 will have a CAM plan for NOx.

The Compliance Assurance Monitoring Plans are provided below:

(1) Compliance Assurance Monitoring Plan – Particulate Matter for Emission Units E-1, E-3, E-5, and E-7:

Emissions Unit

Facility:	Mill Creek Generating Station
Description:	Units 1, 2, 3, and 4 pulverized coal-fired boilers
Identification:	Emission Units E-1, E-3, E-5, and E-7

Applicable Regulations, Emission Limit, and Monitoring Requirements

Applicable Regulations:	Emission Unit E-1: Regulation 6.07
	Emission Unit E-3: Regulation 6.07
	Emission Unit E-5: Regulation 7.06; 40 CFR 60.42 (a)(1)
	Emission Unit E-7: Regulation 7.06; 40 CFR 60.42 (a)(1)
Regulated Pollutant:	Particulate Matter (PM)

Emission Limits:	Emission Unit E-1: 0.11 lb./MMBtu based on a 3-hour average Emission Unit E-3: 0.11 lb./MMBtu based on a 3-hour average Emission Unit E-5: 0.10 lb./MMBtu based on a 3-hour average Emission Unit E-7: 0.10 lb./MMBtu based on a 3-hour average
Monitoring Requirements:	PM CEMs monitor

Control Technology

Electrostatic precipitator (ESP)

Monitoring Approach

The Mill Creek Generating Station Emission Unit E-1, E-3, E-5, and E-7 will use a CEMS that meets 40 CFR 60 requirements for installation, operation and quality assurance to continuously measure sulfur dioxide on the generating units to provide a continuous indication of measured particulate matter (PM) on the generating units. The data reporting system for the CEMS will calculate PM emission rates in terms of lb./MMBtu based on a 3-hr rolling average and compare to the applicable limit.

The Mill Creek Generating Station will perform an annual Method 5 PM stack test while operating at representative conditions to demonstrate compliance with the particulate standard.

Justification

The use of a Continuous Emission Monitoring System that provides measurements in units of the standard for the pollutant of interest meets the criteria in 40 CFR Part 64.3 (d)(2) and is considered presumptively acceptable CAM.

An annual reference method performance test while the units are operating normally will be conducted to demonstrate compliance status with the standard.

(2) Compliance Assurance Monitoring Plan – SO_2 for Emission Unit E-1, E-3, E-5, and E-7

Emissions Unit

Facility:	Mill Creek Generating Station
Description:	Units 1, 2, 3, and 4 pulverized coal-fired boilers
Identification:	Emission Units E-1, E-3, E-5, and E-7

Applicable Regulations, Emission Limit, and Monitoring Requirements

Applicable Regulations:	Emission Unit E-1: Regulation 6.07, Regulation 6.47 Emission Unit E-3: Regulation 6.07, Regulation 6.47 Emission Unit E-5: Regulation 7.06; 40 CFR 60.43 (a) (2), Regulation 6.47 Emission Unit E-7: Regulation 7.06; 40 CFR 60.43 (a) (2), Regulation 6.47
Regulated Pollutant:	sulfur dioxide (SO_2)
Emission Limits:	1.2 lb./MMBtu based on a 3-hour average. SO_2 allocations per the Acid Rain program.
Monitoring Requirements:	40 CFR Part 75 Continuous Emission Monitoring (CEMs)

Control Technology
Wet lime sulfur dioxide scrubber (flue gas desulfurization system)

Monitoring Approach
The Mill Creek Generating Station Emission Unit E-1, E-3, E-5, and E-7 will use a CEMS that meets 40 CFR 75 requirements for installation, operation and quality assurance of data to continuously measure sulfur dioxide on the generating units. The data reporting system for the CEMS will calculate sulfur dioxide emission rates in terms of lb./MMBtu based on a 3-hr rolling average and compare to the applicable limit.

Justification
The use of a Continuous Emission Monitoring System that provides results in units of the standard for the pollutant of interest meets the criteria in 40 CFR Part 64.3 (d)(2) and is considered presumptively acceptable CAM.

(3) Compliance Assurance Monitoring Plan – NOx for Emission Unit E-5, and E-7

Emissions Unit

Facility:	Mill Creek Generating Station
Description:	Units 3 and 4 pulverized coal-fired boilers
Identification:	Emission Units E-5, and E-7

Applicable Regulations, Emission Limit, and Monitoring Requirements

Applicable Regulations:	Regulation 7.06, Regulation 6.42, Regulation 6.47, 40 CFR 60.44 (a)
Regulated Pollutant:	nitrogen oxides (NOx)
Emission Limits:	0.50 lb./MMBtu based on an annual average basis. 0.52 lb./MMBtu based on a rolling 30-day average. NOx allocations per the NOx Budget program.
Monitoring Requirements:	40 CFR Part 75 Continuous Emission Monitoring (CEMs) for installation, operation and quality assurance of data

Control Technology
Selective Catalytic Reduction (SCR)

Monitoring Approach
The Mill Creek Generating Station Emission Unit E-5, and E-7 will use 40 CFR Part 75 CEMS to continuously measure nitrogen oxides on the generating units. The data reporting system for the CEMS will calculate nitrogen oxide emission rates in terms of lb./MMBtu based on a rolling 30-day average and annual average and compare to the applicable limit.

Justification
The use of a Continuous Emission Monitoring System that provides results in units of the standard for the pollutant of interest meets the criteria in 40 CFR Part 64.3 (d)(2) and is considered presumptively acceptable CAM.

Louisville Metro Air Pollution Control District
850 Barret Avenue
Louisville, Kentucky 40204-1745

TITLE IV
PHASE II ACID RAIN PERMIT

Permit No.: 176-97-AR (R4) Plant ID: 0127

Effective Date: 7/31/2014 Expiration Date: 7/31/2019

Permission is hereby given by the Louisville Metro Air Pollution Control District to operate the process(es) and equipment described herein which are located at:

Owner: Louisville Gas & Electric Company
Source: Mill Creek Generating Station
14660 Dixie Highway
Louisville, KY 40272

Statutory and Regulatory Authorities: In accordance with KRS Chapter 77 and Titles IV and V of the Clean Air Act, the Air Pollution Control District of Jefferson County issues this permit pursuant to Regulations 2.16, 6.47, and 7.82.

Application No.: N/A Application Received: 12/13/1995

Permit Writer: Yiqiu Lin

Administratively Complete: 2/11/1996

Acid Rain Permit Revisions/Changes

Revision No.	Issue Date	Public Notice Date	Type	Attachment No./Page No.	Description
Initial	12/17/1997	N/A	Initial	Entire Permit	Initial Issuance
R1	12/31/1998	N/A	Significant	Entire Permit	Added language and SO2 allowances to the tables for each unit
R2	06/01/2003	N/A	Reissuance	Entire Permit	Reissuance of the permit
R3	06/15/2012	N/A	Reissuance	Entire Permit	Reissuance of the permit
R4	7/31/2014	06/05/2014	Renewal	Entire Permit	Renewal of the permit

Acid Rain Permit Conditions

1. SO_2 Allowance Allocations and NO_x Requirements for Unit U1

Unit U1: SO2 Allowances	**SO2 Allowances for Years 2008 – 2009 (tons)**	**SO2 Allowances for Years 2010 and Beyond (tons)**
Table 2 of 40 CFR 73	8,080*	7,696*

Unit U1: NOx Requirements	
NOx Limit	Pursuant to 40 CFR 76, the Kentucky Division for Air Quality approves a Phase II NO_x Compliance Plan which includes a Phase II NO_x Averaging Plan for Unit 1. This plan is effective for calendar year 2013 through 2017. Under the compliance plan, this unit's annual average NO_x emission rate for each year, determined in accordance with 40 CFR 75, shall not exceed the alternative contemporaneous emissions limitation (ACEL) of 0.40 lb/MMBtu in accordance with 40 CFR 76.11(d)(1)(i). If one or more of the units does not meet the requirement under 40 CFR 76.11(d)(1)(i), the owner or operator shall demonstrate that the actual Btu-weighted annual average emission rate for the units in the NOx Averaging Plan is less than or equal to the Btu-weighted annual average rate for the same units, in accordance with 40 CFR 76.11(d)(1)(ii). In addition to the described NO_x compliance plan, this unit shall comply with all other applicable requirements of 40 CFR part 76, including the duty to reapply for a NO_x compliance plan and requirements covering excess emissions.

* The number of allowances actually held by an affected source in a unit account may differ from the number allocated by U.S. EPA. Neither of the aforementioned conditions necessitates a revision to the unit SO_2 allowance allocations identified in this permit (See 40 CFR 72.84). The number of allowances allocated to Phase II affected units by US EPA may change under 40 CFR Part 73.

2. SO_2 Allowance Allocations and NO_x Requirements for Unit U2

Unit U2: SO2 Allowances	**SO2 Allowances for Years 2008 – 2009 (tons)**	**SO2 Allowances for Years 2010 and Beyond (tons)**
Table 2 of 40 CFR 73	8,140*	7,855*

Unit U2: NOx Requirements	
NOx Limit	Pursuant to 40 CFR 76, the Kentucky Division for Air Quality approves a Phase II NO_x Compliance Plan which includes a Phase II NO_x Averaging Plan for Unit 2. This plan is effective for calendar year 2013 through 2017. Under the compliance plan, this unit's annual average NO_x emission rate for each year, determined in accordance with 40 CFR 75, shall not exceed the alternative contemporaneous emissions limitation (ACEL) of 0.40 lb/MMBtu in accordance with 40 CFR 76.11(d)(1)(i). If one or more of the units does not meet the requirement under 40 CFR 76.11(d)(1)(i), the owner or operator shall demonstrate that the actual Btu-weighted annual average emission rate for the units in the NOx Averaging Plan is less than or equal to the Btu-weighted annual average rate for the same units, in accordance with 40 CFR 76.11(d)(1)(ii). In addition to the described NO_x compliance plan, this unit shall comply with all other applicable requirements of 40 CFR part 76, including the duty to reapply for a NO_x compliance plan and requirements covering excess emissions.

* The number of allowances actually held by an affected source in a unit account may differ from the number allocated by U.S. EPA. Neither of the aforementioned conditions necessitates a revision to the unit SO_2 allowance allocations identified in this permit (See 40 CFR 72.84). The number of allowances allocated to Phase II affected units by US EPA may change under 40 CFR part 73.

3. SO_2 Allowance Allocations and NO_x Requirements for Unit U3

Unit U3: SO2 Allowances	**SO2 Allowances for Years 2008 – 2009 (tons)**	**SO2 Allowances for Years 2010 and Beyond (tons)**
Table 2 of 40 CFR 73	10,979*	11,001*

Unit U3: NOx Requirements	
NOx Limit	Pursuant to 40 CFR 76, the Kentucky Division for Air Quality approves a Phase II NO_x Compliance Plan which includes a Phase II NO_x Averaging Plan for Unit 3. This plan is effective for calendar year 2013 through 2017. Under the compliance plan, this unit's annual average NO_x emission rate for each year, determined in accordance with 40 CFR 75, shall not exceed the alternative contemporaneous emissions limitation (ACEL) of 0.46 lb/MMBtu in accordance with 40 CFR 76.11(d)(1)(i). If one or more of the units does not meet the requirement under 40 CFR 76.11(d)(1)(i), the owner or operator shall demonstrate that the actual Btu-weighted annual average emission rate for the units in the NOx Averaging Plan is less than or equal to the Btu-weighted annual average rate for the same units, in accordance with 40 CFR 76.11(d)(1)(ii). In addition to the described NO_x compliance plan, this unit shall comply with all other applicable requirements of 40 CFR part 76, including the duty to reapply for a NO_x compliance plan and requirements covering excess emissions.

* The number of allowances actually held by an affected source in a unit account may differ from the number allocated by U.S. EPA. Neither of the aforementioned conditions necessitates a revision to the unit SO_2 allowance allocations identified in this permit (See 40 CFR 72.84). The number of allowances allocated to Phase II affected units by US EPA may change under 40 CFR part 73.

4. SO_2 Allowance Allocations and NO_x Requirements for Unit U4

Unit U4: SO2 Allowances	**SO2 Allowances for Years 2008 – 2009 (tons)**	**SO2 Allowances for Years 2010 and Beyond (tons)**
Table 2 of 40 CFR 73	13,618*	13,645*

Unit U4: NOx Requirements	
NOx Limit	Pursuant to 40 CFR 76, the Kentucky Division for Air Quality approves a Phase II NO_x Compliance Plan which includes a Phase II NO_x Averaging Plan for Unit 4. This plan is effective for calendar year 2013 through 2017. Under the compliance plan, this unit's annual average NO_x emission rate for each year, determined in accordance with 40 CFR 75, shall not exceed the alternative contemporaneous emissions limitation (ACEL) of 0.46 lb/MMBtu in accordance with 40 CFR 76.11(d)(1)(i). If one or more of the units does not meet the requirement under 40 CFR 76.11(d)(1)(i), the owner or operator shall demonstrate that the actual Btu-weighted annual average emission rate for the units in the NOx Averaging Plan is less than or equal to the Btu-weighted annual average rate for the same units, in accordance with 40 CFR 76.11(d)(1)(ii). In addition to the described NO_x compliance plan, this unit shall comply with all other applicable requirements of 40 CFR part 76, including the duty to reapply for a NO_x compliance plan and requirements covering excess emissions.

* The number of allowances actually held by an affected source in a unit account may differ from the number allocated by U.S. EPA. Neither of the aforementioned conditions necessitates a revision to the unit SO_2 allowance allocations identified in this permit (See 40 CFR 72.84). The number of allowances allocated to Phase II affected units by US EPA may change under 40 CFR part 73.

Comments, Notes, and Justifications:

None

Permit Application:

The Louisville Gas & Electric Company submitted Phase II Permit Application for the Mill Creek Generating Station, dated December 7, 1995, and signed by Chris Hermann. The owners and operators of Louisville Gas and Electric Company must comply with the standard requirements and special provisions set forth in the application.

NO_x Compliance Plan:

Pursuant to 40 CFR 76, the Kentucky Division for Air Quality approves a Phase II NO_x Compliance Plan for Louisville Gas & Electric Company. The owners and operators of Louisville Gas & Electric Company must comply with the alternative contemporaneous emissions limitation for NO_x 0.40 lb/MMBtu for tangentially fired boilers and 0.46 lb/MMBtu for dry bottom wall-fired boilers. Each affected unit in an approved averaging plan is in compliance with the Acid Rain emission limitation for NO_X under the plan only if the requirements under 40 CFR 76.11(d)(1) are met.

Fee Comment

1. The permit fees were based on the administrative permit revision fee for a Title V source ($518.85). The total permit fees are $516.52 for 145-97-TV (R2).

2. The permit fees were based on the significant permit revision fee for a Title V source ($2,594.24) and the administrative permit revision fee for a Title V source ($518.85). The total permit fees are $3,113.09 for 145-97-TV (R3).

3. The permit fees were based on the administrative permit revision fee for a Title V source ($518.85). The total permit fees are $518.85 for 145-97-TV (R4).

4. The permit fees were based on the administrative permit revision fee for a Title V source ($523.02). The total permit fees are $523.02 for 145-97-TV (R5).

5. The permit fees are based on the administrative permit revision fee for a Title V source ($536.10). The total permit fees are $536.10 for 145-97-TV (R6).

Appendix D

Public Hearing Notice & Comments

the job network Homes

Classifieds

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NOTICES

ANNOUNCEMENTS

Happy 100th Birthday

FOUND

GENERAL FOR SALE

CEMETERY LOTS

MISCELLANEOUS

WANTED TO BUY

PETS

DOMESTIC PETS

Purebred

courierjournal.com/newsletters courier journal

PROBATE

Periodic Settlements
Executor: Ruth W. Powell decd Phyllis A. Story exor, Merle Gillespie Garrett decd Marian Copeland exor, Thomas A. Wagner decd Thomas Wagner exor, Joan W. Key decd PNC Bank exor, Mary Ann Kempf decd Theresa Kempf Johnson exor
Administrator: James Milburn decd Geraldine Milburn admx, Edward Nikest decd Chris Meinhart admr, Carroll S. Brown Jr decd Chris Meinhart admr, Joseph Johnson decd Stacy Johnson admx
Periodic Curator: Peggy Lynnn Dunlap pet Jean Ann Hollis cur
Final Settlements
Executor: Richard J. Fitzgerald decd PNC Bank
Administrator: Robert Williams decd Doris Williams, Robert Dale Brewer decd Chris Meinhart admr, Rosie Miller Heavrin decd Chris Meinhart admr, Layonna Beals decd Chris Meinhart admr, Saundra A. Berzinger decd Chris Meinhart admr
Guardian: Raven Lester ch Chris Meinhart gdn, Charles Reed ch Chris Meinhart gdn, Delores Stevenson ch Chris Meinhart gdn, Brandon Craft ch Chris Meinhart gdn, Kameron King ch Chris Meinhart gdn
Conservator:
Kaleb A. Geoverghese ch Philip Geoverghese cons
A copy attest
David L. Nicholson, Circuit Court Clerk
Jefferson District Court Probate
By: Sophia Gibbs, Supervisor

LEGAL

BEER AND LIQUOR LICENSE

PUBLIC NOTICES

CITY OF INDIAN HILLS
LEGAL NOTICE

PUBLIC NOTICE – ALCOHOL LICENSE APPLICATION

... Louisville, Kentucky 40204 Member is Wes Johnson, 108 Bauer Avenue, Louisville, Kentucky 40207 Any person, association, corporation, or body politic may protest the granting of the license(s) by writing the Department of Alcoholic Beverage Control, 1003 Twilight Trail, Frankfort, Kentucky, 40601, within thirty (30) days of the date of legal publication.

... of Fitzgerald Rd., the 1900 block to 2200 block of Garrs Ln. & Farnsley Rd. from Dixie Hwy to Cane Run Road. The complete text of said ord. may be read at the office of the Shively City Clerk, Shively City Hall, 3920 Dixie Highway, Shively, Kentucky 40216. Fenn Cato, 2950 Breckenridge Lane, Suite No. 3 Louisville, KY 40220, Shively City Attorney

Notice of Action on a Title V Construction Permit
The Louisville Metro Air Pollution Control District (District) proposes to issue a construction permit to Clariant Corporation (catalysts and catalyst carrier manufacturing plant), 1227 South 12th Street, in accordance with Regulation 2.16. This permit is being issued to construct a material handling system. The 30-day public comment period starts on October 5, 2019, and ends on November 4, 2019. A public hearing may be scheduled if the District determines that there are germane, unresolved issues or substantial public interest, in accordance with Regulation 2.07.
Drafts of the permit and summary are available at the District office, 701 W. Ormsby Avenue, Suite 303, Louisville, between 8:00 a.m. and 5:00 p.m., Monday through Friday, by calling Matt King at (502) 574-6000, emailing airpermits@louisvilleky.gov, or at the following website: http://www.louisvilleky.gov/APCD/docket. Copies of the application are available upon request. Written comments will be accepted at airpermits@louisvilleky.gov until midnight or at the District office until 5:00 p.m. on November 4, 2019.

2013 Riverside Dream Camper
VIN: 5210T2118DP016719
Owner: Jeremy Alvey
Lienholders/Sellers: Fort Bluegrass Mobile Home Park
3510 Bluegrass Park Dr. Louisville, Ky 40218
Ph: 502-458-7069

Notice is hereby given that, Rafael Dapello 7305 Preston Highway Louisville KY 40219, has filed an application with the energy and environment cabinet, to construct a gravel parking lot for semi-truck and trailer storage. The property is located at 5821 Johnsontown Road Valley Station, Kentucky 40272, located in the Riverport district, 0.8 miles from the Greenbelt Highway. Any comments or objections concerning this application shall be directed to: KY Division of Water, surface water permit branch, flood plain management section, 300 Sower Blvd, Frankfort Ky. 40601 Phone # 502-564-3410

Notice of Non-Discriminatory Policy as to Students
Mercy Academy and Assumption High School admits students of any race, color, national and ethnic origin to all the rights, privileges, programs, and activities generally accorded or made available to students at the schools. They do not discriminate on the basis of race, color, national and ethnic origin in administration of their educational policies, admissions policies, scholarship and loan programs and athletic and other school-administered programs.

Notice of Public Comment Period and Hearing
The Louisville Metro Air Pollution Control District opens a public comment period October 4, 2019, on a Redesignation Request for the Louisville/Jefferson County, KY Partial Nonattainment Area for the 2010 1-Hour SO2 Standard. ...

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INVITATION TO SUBMIT PROPOSAL
LOUISVILLE REGIONAL AIRPORT AUTHORITY
Sealed Proposals will be received at the Authority, 4320 Park Boulevard, Louisville, Kentucky 40209, as follows:
AUTOMOBILE AND EQUIPMENT TIRES
LOUISVILLE MUHAMMAD ALI INTERNATIONAL AIRPORT
Proposals Due: October 16, 2019 at 2:00pm
Bid Documents Available at: flylouisvillebids.com beginning October 2, 2019
The Authority is soliciting bids from Companies for the above services as specified in the bid documents.
The Authority has a No Contact Policy which prohibits contact by proposers or its representatives directed at the Authority, its Board members, employees, consultants, or its other representatives except as permitted by the Proposal Document.

Pursuant to KRS 65.370, the Louisville/Jefferson County Landbank Authority, Inc. is offering vacant structures & vacant lots for sale through their disposition programs. Disposition programs for vacant structures include Request for Proposals (RFP), Last Look-Save the Structure, & Last Look – Demo for Deed. Disposition programs for vacant lots include Side Yard, Cut It Keep It, Budget Rate, & Flex Rate Program details & applications can be found at www.louisvilleky.gov/vacant.

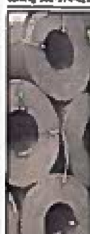
Public Hearings
Louisville Metro Planning Commission
Thursday, October 17, 2019 at 1:00 pm
Old Jail Building, 514 W. Liberty St.

REAL ESTATE

HOMES FOR SALE

HOME FOR SALE BY OWNER

FARMS AND ACREAGE



GREG FISCHER
MAYOR

AIR POLLUTION CONTROL DISTRICT
LOUISVILLE, KENTUCKY

KEITH H. TALLEY, SR.
DIRECTOR

Notice of Cancellation of Public Hearing for the Redesignation Request for the Louisville/Jefferson County, KY Partial Nonattainment Area for the 2010 1-Hour SO2 Standard Revision to the Kentucky State Implementation Plan

The Louisville Metro Air Pollution Control District opened a public comment period October 4, 2019, on the proposed Redesignation Request for the Louisville/Jefferson County, KY Partial Nonattainment Area for the 2010 1-Hour SO2 Standard revision to the Jefferson County portion of the Kentucky State Implementation Plan (SIP).

The public hearing related to this Determination, scheduled for 10:00 a.m., November 20, 2019, was not requested prior to the deadline of 5:00 p.m., November 8, 2019. Because a request for a public hearing not was received by the deadline, the hearing has been cancelled.

Louisville Metro Air Pollution Control District
Responses to Proposed Redesignation Request, Louisville/Jefferson County, KY Partial Nonattainment Area, 2010 1-Hour SO2 Standard
Proposed for Public Comment on October 4, 2019

Commenter: U.S. Environmental Protection Agency (EPA)

Comment

1. **Section VI.E, page 18 - Contingency Plan** – As discussed on October 15, 2019, the EPA recommends clarifying the nature of the "exceedance" trigger and revising the fourth sentence of the third paragraph to read "LMPACD will continue to implement all measures with respect to the control of SO_2 which were contained in the state implementation plan for the area before redesignation."

Response:

The first sentence of the second paragraph of this section has been changed to read "In the event of a single monitored exceedance of the one-hour, 75 ppb SO2 NAAQS in the future…." This is intended to clarify that the trigger for the actions in the remainder of the section is a single exceedance of the one-hour standard.

In addition, the suggested change to the fourth sentence of the third paragraph has been made.

Comment

2. As discussed on October 15, 2019, the EPA recommends that the Louisville Metro Air Pollution Control District (LMAPCD) and Kentucky acknowledge how the Commonwealth has demonstrated compliance with the reasonably available control measures/technology requirements of section 172(c)(1) based on the 6th circuit's March 18, 2015, court decision for redesignation purposes.

Response:

As discussed at length in Section IV of the Redesignation Request, LMAPCD has submitted, and U.S. EPA has approved, a complete Implementation Plan meeting all of the requirements of sections 110(a), 172, 191, and 192 of the Clean Air Act, including requirements of reasonably available control measures/technology (RACM/RACT). This also satisfies the requirements of the referenced decision.

The decision of the court in *Sierra Club v. U.S. EPA*, 793 F.3d 656 (6th Cir., 2015), was not specifically discussed in the Redesignation Request because LMAPCD believes that decision had no particular impact on the standard process dealing with impacts from a localized source like the one at issue here. That decision dealt specifically with an area that came into attainment due to regional reductions and was redesignated prior to ever submitting an implementation plan (including RACM/RACT). In other words, while the decision of the 6th Circuit was not contravened, LMAPCD would have followed the same process in this situation regardless of that decision.

Comment

3. **Section VI.A and B** – The EPA appreciates the additional explanation regarding the application of the EPA's Air Emissions Modeling (2023en and 2028el) 2011v6.3 modeling platform that LMAPCD utilized to derive the nonpoint, nonroad and onroad SO_2 projected emissions inventory provided in Table 5. The EPA recommends LMAPCD consider providing additional clarification on the following:
   - Identify what emissions data or factors were utilized from the 2011v6.3 modeling platform to develop the projected emission inventory.

Response:

The following information was added to footnote 33, clarifying which specific data was used:

> Specifically, the files "2023en_county_monthly_report.xlsx"; and "2028el_county_monthly_report.xlsx" within the subfolders "2011en_and_2023en", and "2028el" contain summaries of the 2023 and 2028 inventories, respectively. The "ann_value" for "poll" "SO2" for the "sector_group"s "nonpoint", "nonroad", and "onroad" for "region_cd" 21111 (Jefferson County, Kentucky) were summed to get the inventories for these sectors and years.

Comment

- Describe how these emission data or factors were used to derive the 2032 projected SO_2 emissions inventory for the nonpoint, nonroad and onroad source categories listed in Table 5 (see page 17) including any assumptions the air agencies used to obtain projected emission inventory for the nonattainment area.

Response:

See the first sentence of the fifth paragraph of section VI.B.: "For the 2032 Maintenance Inventory, emissions for all sectors except point sources were chosen based on the higher of either 2023 or 2028 U.S. EPA projected emissions."

Comment

- How the 2023 and 2028 interim years projected emission inventory listed in Table 5 for nonroad, onroad and non-point sources were developed (e.g. interpolation of emission inventory data/factors from the 2011v6.3 modeling platform etc. including any assumptions).

Response:

See the response above describing the additional language at footnote 33. No interpolation or assumptions were used, other than the apportionment to the nonattainment area based on the fraction of land area covered within the county, as described in the body of the Redesignation Request immediately before the footnote.

Comments

- Consider referencing the Data Tables associated with the 2011v6.3 modeling platform Technical Support Document (TSD).
- Reference EPA's TSD for the 2011v6.3 modeling platform weblink entitled "Technical Support Document (TSD) Preparation of Emissions Inventories for the Version 6.3, 2011 Emissions Modeling Platform" (See *https://www.epa.gov/sites/production/files/2016-09/documents/2011v6_3_2017_emismod_tsd_aug2016_final.pdf*).

Response:

See added footnote 34, "*See* U.S. EPA, Technical Support Document (TSD) Preparation of Emissions Inventories for the Version 6.3, 2011 Emissions Modeling Platform, *available at* https://www.epa.gov/sites/production/files/2016-09/documents/2011v6_3_2017_emismod_tsd_aug2016_final.pdf". In addition, as described in the paragraphs preceding it, Table 5 specifically deals in part with the data from the 2011v6.3 modeling platform, and the referenced TSD.