Cokenergy, LLC
3210 Watling Street
Mail Code 2-991
East Chicago, Indiana 46312

April 29, 2019

Chief, Environmental Enforcement Section
Environment and Natural Resources Division
U.S. Department of Justice
Box 7611, Ben Franklin Station
Washington, DC 20044-7611
Re: DOJ No. 90-5-2-1-08555/1

Air Enforcement Division Director
U.S. Environmental Protection Agency
Office of Civil Enforcement
Air Enforcement Division
U.S. Environmental Protection Agency
1200 Pennsylvania Ave, NW Mail Code: 2242A
Washington, DC 20460

Compliance Tracker
Air Enforcement and Compliance Assurance Branch
U.S. Environmental Protection Agency – Region 5
77 West Jackson Blvd. AE-18J
Chicago, IL 60604-3590

Including an electronic copy to:
R5airenforcement@epa.gov

Susan Tennenbaum
U.S. Environmental Protection Agency
Region 5
C-14J
77 West Jackson Blvd
Chicago, IL 60640

Including an electronic copy to:
tennenbaum.susan@epa.gov

Phil Perry
Indiana Department of Environmental Management
Chief, Air Compliance and Enforcement Branch
100 North Senate Avenue
MC-61-53, IGCN 1003
Indianapolis, IN 46204-2251

Elizabeth A. Zlatos
Indiana Department of Environmental Management
Office of Legal Counsel
100 North Senate Avenue
MC-60-01, IGCN 1307
Indianapolis, IN 46204-2251

Including an electronic copy to:
bzlatos@idem.in.gov

Subject: Consent Decree, United States, et al. v. Indiana Harbor Coke Company, et al.
Cokenergy, LLC (Part 70 Permit No. T089-38695-00383)
Semi-Annual Progress Report – October 25, 2018 through March 31, 2019

To Whom It May Concern:

In accordance with Section VIII (Reporting Requirements), Paragraph 51. of the consent decree (18-cv-35), Cokenergy, LLC has prepared a semi-annual progress report detailing activities beginning with the effective date of October 25, 2018 until March 31, 2019. This report provides an update on Cokenergy's activities during the reporting period. Indiana Harbor Coke Company (IHCC) activities will be provided under a separate cover prepared and submitted by IHCC.

Paragraph 51.a. requires details on work performed and progress made towards implementing the requirements of Section IV (Compliance Requirements), including completion of any milestones. The following paragraphs provide an update on our compliance requirements.

Bypass Venting

Paragraph 14.a – *Annual Bypass Venting Limit - From January 1, 2017, through December 31, 2019, a maximum of 12% of the Coke Oven waste gases leaving the common tunnel shall be allowed to be vented to the atmosphere through the Bypass Vent Stacks, as determined on an annual basis.*

- Bypass venting for the period of January 1, 2018 – December 31, 2018 was 6.00%.
- Bypass venting for the period of January 1, 2019 – March 31, 2019 was 2.37%.

Paragraph 15. – *Daily Bypass Venting Limit – A Maximum of 19% of the Coke Oven waste gases leaving the common tunnel shall be allowed to be vented to the atmosphere through the Bypass Vent Stacks on a twenty-four (24) hour average.*

- During the reporting period of October 25, 2018 through March 31, 2019 there were no incidents of exceedance of the Daily Bypass Venting Limit.

Paragraph 16. – *SO2 Daily Limit – Defendants shall limit SO2 emissions from the Main Stack and Bypass Vent Stacks to 1,656 lbs/hr for a twenty-four (24) hour average.*

- During the reporting period of October 25, 2018 through March 31, 2019 there were no incidents of exceedance of the SO2 Daily Limit.

Paragraph 17. – *Emissions Minimization*

- During the reporting period of October 25, 2018 through March 31, 2019 there were no incidents of exceedance of the Daily Bypass Venting Limit, therefore it was not necessary to implement any Emissions Minimization measures. (Paragraph 51.f.)

Paragraph 18. – *Bypass Venting Incident Root Cause Failure Analysis*

- During the reporting period of October 25, 2018 through March 31, 2019 there were no incidents of exceedance of the Daily Bypass Venting Limit, therefore there were no Bypass Venting Incident RCFA completed. (Paragraph 51.g. and 51.h.)

Enhanced Monitoring

Paragraph 19. – *Permanent Flow Monitor - Milestone complete*

- Cokenergy installed a permanent flow monitor on the Main Stack and the initial certification testing was completed on September 14, 2018. The initial certification testing included a 7-day drift test and a Relative Accuracy Test Audit (RATA). Cokenergy submitted the initial certification report to the government and East Chicago Public Libraries on October 17, 2018. IDEM notified Cokenergy on November 16, 2018 that the monitor successfully demonstrated compliance with the requirements of Performance Specification (PS) 6 of 40 CFR60, Appendix B.

Paragraph 21. – *ETS Updates - Milestone complete*

- The Main Stack flow monitor was incorporated into ETS on November 27, 2018 to allow for the calculation of SO2 emissions from the Main Stack using the actual stack volumetric flow rate. ETS continues to utilize in its emission calculations a monthly average of Sulfur Content and moisture content.

Preventive Maintenance and Operation Plans

Paragraphs 23 and 23.b. – *Cokenergy PMO Plan for HRSGs and FGD- Milestone complete*

- Cokenergy submitted our PMO plan to the government on June 28, 2018. The government provided notification of their conditional approval of the PMO plan on August 24, 2018. Cokenergy provided our response to the government's comments on December 12, 2018, and the government provided final approval of the PMO plan on February 12, 2019.

Paragraph 23.c. – *Compliance Assurance*

- The CAP is addressed in Section 9.0 of Cokenergy's PMO Plan. IHCC has not reported production levels in excess of rates included in 23. c. i. during the reporting period of October 25, 2018 – March 31, 2019.

Paragraph 23.d. – *Defendants shall comply with the PMO Plans at all times, including periods of startup, shutdown, and malfunction of the HRSG and FGD.*

- Cokenergy has fully implemented our PMO plan and is following the requirements of the PMO plan.

Mitigation Measures

Paragraph 24 – *Dual SDA Operation*

- Cokenergy has successfully operated the SDAs in dual operation mode prior to the effective date of the CD, except during periods of planned maintenance. SO2 emissions for the period of October 25, 2018 through December 31, 2018 were 1,135.7 tons versus the limit of 1,148.5 tons (6,165 tons/year prorated for the 68 days of 2018 in which the CD was effective).

- The emissions of SO2 during the 1st quarter of 2019 are approximately 1,359 tons, which projects to be less than 6,165 tons/year.

Permits

Paragraph 27.a. - *Applications for Permits Incorporating the Requirements in Section IV- Milestone complete*

- Cokenergy submitted our permit application to IDEM on January 4, 2019 within the ninety (90) Day requirement specified in the CD. IDEM issued the Significant Source Modification (089-40905-00383) and Significant Permit Modification (089-41033-00383) for Public Comment on March 4, 2019. The Public Comment period ended on April 3, 2019. (Paragraph 51.k.)

Paragraph 27.b. – *Application to seek a site-specific revision to the Indiana State Implementation Plan ("SIP") at 326 IAC 7-4.1-7 and 326 IAC 7-4.1-8 - Milestone complete*

- Cokenergy formally submitted our request to modify the SIP on December 18, 2018 within the ninety (90) Day requirement specified in the CD. (Paragraph 51.k.).

Paragraph 28. – *Permitting Authority Cooperation*

- Cokenergy has actively worked with the IDEM permit writer throughout the permitting process.

Paragraph 29. – Submittal of Permit Applications to EPA

- Cokenergy has provided copies of our complete permit application to EPA on the dates specified above in accordance with the requirements specified in Section XV (Notices) of the CD.

The following paragraphs provide a status update on the requirements of Paragraphs 51.b. through 51.p. that were not addressed above as applicable to Cokenergy operations.

Cokenergy has no modifications to report. Dual SDA operation is our normal operating mode and the Permanent Flow Monitor has been fully integrated into our Continuous Emissions Monitoring System (CEMS) and the Emissions Tracking System (ETS). (Paragraph 51.b.)

Cokenergy did not encounter any problems or anticipate any problems in complying with the Compliance Requirements (Paragraph 51.c.).

Cokenergy has not completed any stack testing required in Paragraph 22. Cokenergy submitted the initial certification report for the Permanent Flow Monitor to the government and East Chicago Public Libraries on October 17, 2018. (Paragraph 51.d.)

Cokenergy has made some minor edits to the PMO Plan after receiving approval of the plan on February 12, 2019. The edits correct minor errors in the tube wall thickness table in Section 4.5 and the SDA Inspection Table 4. A copy of the revised PMO Plan is provided as an attachment to this report. (Paragraph 51.i.)

Cokenergy does not have any noncompliance with the Section VII SEP requirements to report per Paragraph 51.l. Cokenergy is working with Elevate Energy on the lead abatement SEP. Pursuant to Paragraph 42, Cokenergy has submitted the SEP Plan to the government on April 22, 2019 (Milestone complete).

Per Paragraph 51.m. there have been no failures to comply with the reporting requirements in Paragraphs 51, through 55.

Per Paragraph 51.n. Cokenergy has attached copies of the following reports:

- Fourth Quarter 2018 Deviation and Compliance Monitoring Report;
- First Quarter 2019 Deviation and Compliance Monitoring Report; and
- 2018 Annual Compliance Certification.

Pursuant to Paragraph 51.o. the following table is a summary of Lightning Stand-Downs during the October 25, 2018 through March 31, 2019 reporting period.

Start Date/Time	Lightning Warning Detail	End Date/Time	Duration	Compliance response impacted due to lightning stand down
10/30/2018 23:12	Alert: Ltg Warning (southwest 9)	10/31/2018 0:21	1:09:00	None
11/4/2018 10:18	Alert: Ltg Warning (northwest 10)	11/4/2018 10:49	0:31:00	None
12/1/2018 14:24	Alert: Ltg Warning (southeast 8)	12/1/2018 15:01	0:37:00	None
12/1/2018 22:07	Alert: Ltg Warning (southwest 8)	12/1/2018 22:57	0:50:00	None
2/5/2019 21:31	Alert: Ltg Warning (west 6)	2/5/2019 22:29	0:58:00	None
2/6/2019 19:37	Alert: Ltg Warning (north 7)	2/6/2019 20:08	0:31:00	None
3/9/2019 17:30	Alert: Ltg Warning (south 7)	3/9/2019 18:08	0:38:00	None
3/14/2019 10:53	Alert: Ltg Warning (southwest 9)	3/14/2019 11:57	1:04:00	None
3/14/2019 13:36	Alert: Ltg Warning (southeast 10)	3/14/2019 15:02	1:26:00	None

Per Paragraph 51.p. there were no power outages to report during the October 25, 2018 through March 31, 2019 reporting period.

If you have any questions regarding this semi-annual progress report, please contact me at (219) 397-4626 or email at lford@primaryenergy.com.

I certify under penalty of law that this information was prepared under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gather and evaluate the information submitted. Based on my directions and my inquiry of the person(s) who manage the system, or the person(s) directly responsible for gathering the information, the information submitted is, to the best of my knowledge and belief, true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment for knowing violations.

Sincerely,

Luke E. Ford
Director EH&S
Primary Energy

cc: Keith Kaufman (via email)
Thor Ketzback, BCLP (via email)
Justin Kirby, IHCC (via email)
Katie Batten, Suncoke (via email)

East Chicago Public Library
2401 E. Columbus Drive
East Chicago, Indiana 46312

East Chicago Public Library
1008 W. Chicago Avenue
East Chicago, Indiana 46312

Attachments

File: X://675

ATTACHMENT 1

Fourth Quarter 2018 Deviation and Compliance Monitoring Report

Cokenergy LLC
3210 Watling Street MC 2-991
East Chicago, IN 46312

January 22, 2019 Via UPS

Indiana Department of Environmental Management
Compliance and Enforcement Branch
Office of Air Quality
100 N. Senate Avenue
Mail Code 61-50, IGCN 1003
Indianapolis, IN 46204 - 2251

RE: Cokenergy, LLC Quarterly Report – Fourth Quarter 2018
Part 70 Permit No. T089-36965-00383

To Whom It May Concern:

In accordance with sections C.18 and D.1.14 of the subject permit, 326 IAC 3-5-5 and 326 IAC 3-5-7, we have enclosed the fourth quarter 2018 reports for the Cokenergy, LLC facility. This report includes:

- Part 70 Quarterly Report – Certification
- Part 70 Quarterly Deviation and Compliance Report
- CEMS Excess Emissions Report
- CEMS Downtime Report
- COMS Fourth Quarter 2018 Opacity Monitor Audit
- COMS Clear Stack Report
- CEMS Fourth Quarter Cylinder Gas Audit

The United States District Court for the Northern District of Indiana entered Civil Action No. 18-cv-35 (Consent Decree) with an effective date of October 25, 2018. A requirement of the consent decree was the installation of a continuous flow monitoring system.

Cokenergy has installed the permanent flow monitor on June 12, 2018 and completed the initial certification testing on September 12, 2018. IDEM notified us on November 16, 2018 that the new flow monitoring system had successfully demonstrated compliance with the requirements of *Performance Specification (PS) 6 of 40 CFR 60, Appendix B* and is certified for use. In addition, Cokenergy has submitted a minor Title V Operating Permit Modification on January 4, 2019 to incorporate the flow monitoring system into the permit. We have included the flow monitoring system in our downtime and emissions reporting for the entire 4th quarter of 2018.

If you have any questions concerning this data, please call Luke Ford at (219) 397-4626.

Sincerely,

Keith C. Kaufman
General Manager
Cokenergy LLC

Enclosure
cc: Luke Ford (scan via email)
Cliff Yukawa IDEM (scan via email)

File: X:\\ 615.4

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
OFFICE OF AIR MANAGEMENT
COMPLIANCE AND ENFORCEMENT SECTION
PART 70 OPERATING PERMIT
CERTIFICATION

Source Name: Cokenergy LLC

Source Address: 3210 Watling Street, MC 2-991, East Chicago, Indiana 46312-1610

Part 70 Permit No. : T089-36965-00383

This certification shall be included when submitting monitoring, testing reports/results or other documents as required by this permit.

Please check what document is being certified:

☐ Annual Compliance Certification Letter

☒ Test Result (specify) 4th Quarter 2018 COMS Performance Audit, COMS Clear Stack, & Cylinder Gas Audit

☒ Report (specify) 4th Quarter 2018 Deviation and Compliance Monitoring Report

☐ Notification (specify) ______

☐ Affidavit (specify) ______

☐ Other (specify) ______

I certify that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete.

Signature: Keith C. Kaufman

Printed Name: Keith C. Kaufman

Title/Position: General Manager, Cokenergy, LLC

Phone: (219) 354-5009

Date: January 22, 2019

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
OFFICE OF AIR QUALITY
COMPLIANCE AND ENFORCEMENT BRANCH
PART 70 OPERATING PERMIT
QUARTERLY DEVIATION AND COMPLIANCE MONITORING REPORT

Source Name: Cokenergy LLC
Source Address: 3210 Watling Street, MC 2-991, East Chicago, Indiana 46312-1610
Part 70 Permit No. : T089-36965-00383

Months: October **to** December **Year:** 2018

This report shall be submitted quarterly based on a calendar year. Any deviation from the requirements, the date(s) of each deviation, the probable cause of the deviation, and the response steps taken must be reported. Deviations that are required to be reported by an applicable requirement shall be reported according to the schedule stated in the applicable requirement and do not need to be included in this report. Additional pages may be attached if necessary. If no deviations occurred, please specify in the box marked "No deviations occurred this reporting period".
☒ NO DEVIATIONS OCCURRED THIS REPORTING PERIOD
☐ THE FOLLOWING DEVIATIONS OCCURRED THIS REPORTING PERIOD

Permit Requirement: (specify permit condition #)	
Date of Deviation:	**Duration of Deviation:**
Number of Deviations:	
Probable Cause of Deviation:	
Response Steps Taken:	

Permit Requirement: (specify permit condition #)	
Date of Deviation:	**Duration of Deviation:**
Number of Deviations:	
Probable Cause of Deviation:	
Response Steps Taken:	

Permit Requirement: (specify permit condition #)	
Date of Deviation:	**Duration of Deviation:**
Number of Deviations:	
Probable Cause of Deviation:	
Response Steps Taken:	

Permit Requirement: (specify permit condition #)	
Date of Deviation:	**Duration of Deviation:**
Number of Deviations:	
Probable Cause of Deviation:	
Response Steps Taken:	

Permit Requirement: (specify permit condition #)	
Date of Deviation:	**Duration of Deviation:**
Number of Deviations:	
Probable Cause of Deviation:	
Response Steps Taken:	

Form Completed by: Keith C. Kaufman

Title / Position: General Manager, Cokenergy, LLC

Date: January 22, 2019

Phone: (219) 354-5005

Excess Emissions and Downtime Report

COKENERGY, LLC, East Chicago, IN
Plant ID: 089-00383
Emissions Unit ID: Stack 201
Emissions Unit: Heat Recovery Coke Carbonization Waste Heat Stack

PLANT OPERATIONS DOWNTIME SUMMARY

Reporting Period: 4th Quarter of 2018

Commencement of Emission Unit Downtime	Completion of Emission Unit Downtime	Emission Unit Downtime Duration (hours)	Reasons for Emission Unit Downtime
		None	
Total Emission Unit Downtime for the quarter =		0	hours

COKENERGY, LLC, East Chicago, IN
Plant ID: 089-00383
Emissions Unit ID: Stack 201
Emissions Unit: Heat Recovery Coke Carbonization Waste Heat Stack

EXCESS EMISSIONS SUMMARY

Reporting Period: 4th Quarter of 2018

SO_2 Exceedances

Emission Standard: 1,656 lb/hr on a 24-hr average basis
(Note that this limit is for the combined emissions from Cokenergy Stack 201 and 16 IHCC Vent Stacks)

Date/Time of Commencement	Date/Time of Completion	Magnitude of Emissions (lb/hr)			Reasons for Excess Emissions	Corrective Actions Taken
		Main Stack Avg	Vent Stack Avg	Plant Avg		
None						

COKENERGY, LLC, East Chicago, IN
Plant ID: 089-00383
Emissions Unit ID: Stack 201
Emissions Unit: Heat Recovery Coke Carbonization Waste Heat Stack

EXCESS EMISSIONS SUMMARY

Reporting Period: 4th Quarter of 2018

Opacity Exceedances

Emission Standard: 20% opacity

Date/Time of Commencement	Date/Time of Completion	Magnitude of Emissions	Reasons for Excess Emissions	Corrective Actions Taken
		None		

COKENERGY, LLC, East Chicago, IN
Plant ID: 089-00383
Emissions Unit ID: Stack 201
Emissions Unit: Heat Recovery Coke Carbonization Waste Heat Stack

CONTINUOUS MONITORING SYSTEM DOWNTIME SUMMARY

Reporting Period: 4th Quarter of 2018

Opacity Monitor Downtime

Date/Time of Commencement	Duration of Downtime (minutes)	Reasons for Instrument Downtime	System Repairs and Adjustments
11/14/18 9:00	60	Quarterly PMs and filter audit	Routine preventative maintenance and quarterly audits
11/16/18 9:00	120	Opacity clear stack audit	Complete audit
Total Downtime	180 minutes		

Note: Daily zero and span checks of the instrument have been excluded from the downtime summary per 326 IAC 3-5-7.

COKENERGY, LLC, East Chicago, IN
Plant ID: 089-00383
Emissions Unit ID: Stack 201
Emissions Unit: Heat Recovery Coke Carbonization Waste Heat Stack

CONTINUOUS MONITORING SYSTEM DOWNTIME SUMMARY

Reporting Period: 4th Quarter of 2018

SO_2 CEMS Downtime

Date/Time of Commencement	Duration of Downtime (hours)	Reasons for Instrument Downtime	System Repairs and Adjustments
11/14/18 9:00	120	Quarterly PMs and Cylinder Gas Audit	Routine preventative maintenance and Cylinder Gas Audit
Total Downtime	120.0		

Note: Daily zero and span checks of the instrument have been excluded from the downtime summary per 326 IAC 3-5-7.

COKENERGY, LLC, East Chicago, IN
Plant ID: 089-00383
Emissions Unit ID: Stack 201
Emissions Unit: Heat Recovery Coke Carbonization Waste Heat Stack

CONTINUOUS MONITORING SYSTEM DOWNTIME SUMMARY

Reporting Period: 4th Quarter of 2018

Flow Monitor Downtime

Date/Time of Commencement	Duration of Downtime (minutes)	Reasons for Instrument Downtime	System Repairs and Adjustments
11/14/18 9:00	60	Quarterly PMs	Routine preventative maintenance
Total Downtime	60 minutes		

Note: Daily zero and span checks of the instrument have been excluded from the downtime summary per 326 IAC 3-5-7.

CYLINDER GAS AUDIT

FOR

Primary Energy

E. Chicago, IN

Unit: Stack 201

MONITORING SOLUTIONS, INC.
FULL EXTRACTIVE

Fourth (4th) Quarter Results
2018

CGA Completed On: 11/14/2018

PREPARED BY:

Monitoring Solutions
Leaders in Environmental Monitoring Systems & Services

TABLE OF CONTENTS

LIST OF TABLES

I. Introduction

Monitoring Solutions, Inc. was contracted to conduct a Cylinder Gas Audit on a Continuous Emission Monitoring System (CEMS). This audit was performed:

Client: Primary Energy
City, State: E. Chicago, IN
Unit: Stack 201
Auditor: Dan Bowles
Audit Date: 11/14/2018

The audit of the Continuous Emission Monitoring System was conducted for the following gases:

Gas #1 : SO_2
Gas #2 : O_2 Dry & O_2 Wet

Our assessment of this quarter's CGA results indicates that all of the analyzers evaluated during this test program meet the accuracy requirements as outlined in 40 CFR 60, Appendix F.
NOTE: Table 1-1 summarizes the results for the cylinder gas audit.

Reviewed by: Ethan [signature]

Date: 12/14/2018

Revision: June 2016

Summary of Cylinder Gas Audit Results

Parameter	Low Gas Error	Mid Gas Error
SO2	1.68	0.84
O2 Dry	0.00	2.31
O2 Wet	3.33	0.03
	Pass	Pass

Table 1-1

40 CFR 60, Appendix F Performance Test requirements: <15%

II. CYLINDER GAS AUDIT PROCEDURES

Each Continuous Emission Monitor (CEM) must be audited three out of four calendar quarters of each year. As part of the Quality Control (QC) and Quality Assurance (QA) procedures, the quality of data produced is evaluated by response accuracy compared to known standards,

The Cylinder Gas Audit (CGA) for this quarter was conducted in accordance with the QA/QC procedure outlined in 40 CFR 60, Appendix F.

All applicable audit gases are connected to the sampling system. Each gas is introduced into the sampling and analysis system. The gases flow through as much of the sampling path as possible.

The gases are actuated on and off by utilizing a computer and/or PLC controlled solenoids at designated time intervals.

a) Challenge each monitor (both pollutant and diluent, if applicable) with cylinder gases of known concentrations at two measurement points listed in Table 1-2.

b) Use a separate cylinder gas for measurement points 1 and 2. Challenge the CEMS three times at each measurement point and record the responses.

c) Use cylinder gases that have been certified by comparison to National Institute of Standards and Technology (NIST) gaseous standard reference material (SRM) or NIST/EPA approved gas manufacturer's certified reference material (CRM) following ''Traceability Protocol for Establishing True Concentrations of Gases Used for Calibration and Audits of Continuous Source Emission Monitors. (Protocol Number 1).''

NOTE: In rare cases, some operators may have pollutant cylinder gases that are not "Protocol 1". Pollutant cylinder gases in high concentrations may not be certifiable to the "Protocol 1 Standard" and are only available as a "Certified Standard" (e.g. Sulfur Dioxide [SO2] in a concentration of 3.0% - or - 30,000 ppm).

Gas	***Measurement point #1***	***Measurement point #2***
Pollutants -	20-30% of span value	50-60% of span value
Diluent - O_2	4-6% by volume	8-12% by volume
Diluent - CO_2	5-8% by volume	10-14% by volume

Table 1-2

NOTE: Some operators may have cylinder gas values that fall outside of these parameters. This may be a result of previous agreements with their state or local EPA authority.

d) Determine the Relative Accuracy of each measurement point using the formula below. The RA error must not exceed 15%.

$$RA = \left|\left(\frac{\bar{d}}{AC}\right)100\right| \qquad \leq 15 \text{ percent}$$

Where:
RA = Relative Accuracy
$\bar{d}$ = Average of the three responses (Arithmetic Mean)
AC = The certified concentration of the cylinder gas.

III. Cylinder Gas Audit Data Sheets

CYLINDER GAS AUDIT (CGA) ERROR DETERMINATION

CLIENT: Primary Energy
PLANT / SITE: E. Chicago, IN
UNIT ID: Stack 201

CONDUCTED BY : Dan Bowles
ATTENDEE : N/A
AUDIT DATE: 11/14/2018

MONITOR TESTED: SO_2
RANGE : 0 - 700 PPM

ANALYZER SERIAL NUMBER: 1152150034

	Run	Time	Reference value	Monitor value	Difference	Error %
Low-level	1	10:49	176.50	179.00	2.50	1.42 %
	2	11:07	176.50	180.00	3.50	1.98 %
	3	11:25	176.50	179.40	2.90	1.64 %
Mid-level	1	10:43	387.30	391.20	3.90	1.01 %
	2	11:01	387.30	389.90	2.60	0.67 %
	3	11:19	387.30	390.60	3.30	0.85 %

Low-level

Arithmetic Mean: 179.47

CGA Error: 1.68 %

Tank S/N CC14789

Tank Expiration Date 7/25/2025

Mid-Level

Arithmetic Mean: 390.57

CGA Error: 0.84 %

Tank S/N CC89122

Tank Expiration Date 7/17/2025

Primary Energy Coke

CGA Report

Created on : Nov 14, 2018 11:31:49

East Chicago, IN

11/14/2018 - 11/14/2018

STACK 201

Date	Parameter	Run#	Timestamp	Type	Expected	Measured	Low Diff	-------	Mid Diff	-------
11/14/2018										
	SO2, PPM	1	10:43:12	QTR_MID	387.3	391.2			3.9	
	SO2, PPM	1	10:49:12	QTR_LOW	176.5	179.0	2.5			
	SO2, PPM	2	11:01:12	QTR_MID	387.3	389.9			2.6	
	SO2, PPM	2	11:07:13	QTR_LOW	176.5	180.0	3.5			
	SO2, PPM	3	11:19:13	QTR_MID	387.3	390.6			3.3	
	SO2, PPM	3	11:25:13	QTR_LOW	176.5	179.4	2.9			

Arithmetic Mean of Quarterly Low : 179.5
Linearity Error of Quarterly Low : 1.7
Calibration Tolerance: 15.0

Arithmetic Mean of Quarterly Mid : 390.6
Linearity Error of Quarterly Mid : 0.8
Calibration Tolerance: 15.0

Calibration Result : Pass

CEMS Type : Full Extractive
Manufacturer: Thermo
Model Number : 43i-HL
Serial Number: 1152150034
Monitor Certification Date:

Tested By : ______________________________

Date: ______________________________

CYLINDER GAS AUDIT (CGA) ERROR DETERMINATION

CLIENT: Primary Energy
PLANT / SITE: E. Chicago, IN
UNIT ID: Stack 201

MONITOR TESTED: O2 Wet
RANGE : 0 - 25 %

CONDUCTED BY : Dan Bowles
ATTENDEE : N/A
AUDIT DATE: 11/14/2018

ANALYZER SERIAL NUMBER: 11401

	Run	Time	Reference value	Monitor value	Difference	Error %
Low-level	1	10:49	5.00	4.80	-0.20	-4.00 %
	2	11:07	5.00	4.80	-0.20	-4.00 %
	3	11:25	5.00	4.90	-0.10	-2.00 %
Mid-level	1	10:55	9.97	9.90	-0.07	-0.70 %
	2	11:13	9.97	10.00	0.03	0.30 %
	3	11:31	9.97	10.00	0.03	0.30 %

Low-level

Arithmetic Mean: 4.83

CGA Error: 3.33 %

Tank S/N CC14789
Tank Expiration Date 7/25/2025

Mid-Level

Arithmetic Mean: 9.97

CGA Error: 0.03 %

Tank S/N CC400438
Tank Expiration Date 8/16/2025

CGA Report

11/14/2018 - 11/14/2018

Date	Parameter	Run#	Timestamp	Type	Expected	Measured	Low Diff	-------	Mid Diff	-------
11/14/2018										
	O2 WET, %	1	10:49:12	QTR_LOW	5.0	4.8	0.2			
	O2 WET, %	1	10:55:12	QTR_MID	10.0	9.9			0.1	
	O2 WET, %	2	11:07:13	QTR_LOW	5.0	4.8	0.2			
	O2 WET, %	2	11:13:13	QTR_MID	10.0	10.0			0.0	
	O2 WET, %	3	11:25:13	QTR_LOW	5.0	4.9	0.1			
	O2 WET, %	3	11:31:13	QTR_MID	10.0	10.0			0.0	

Arithmetic Mean of Quarterly Low : 4.8
Linearity Error of Quarterly Low : 3.5
Calibration Tolerance: 15.0

Arithmetic Mean of Quarterly Mid : 10.0
Linearity Error of Quarterly Mid : 0.0
Calibration Tolerance: 15.0

Calibration Result : Pass

CEMS Type : Full Extractive
Manufacturer: Brand Gaus
Model Number : 4705
Serial Number: 11401
Monitor Certification Date:

Tested By : ______________________________

Date: ___________________________________

CYLINDER GAS AUDIT (CGA) ERROR DETERMINATION

CLIENT: Primary Energy
PLANT / SITE: E. Chicago, IN
UNIT ID: Stack 201

MONITOR TESTED: O2 Dry
RANGE : 0 - 25 %

CONDUCTED BY : Dan Bowles
ATTENDEE : N/A
AUDIT DATE: 11/14/2018

ANALYZER SERIAL NUMBER: 11400

	Run	Time	Reference value	Monitor value	Difference	Error %
Low-level	1	10:49	5.00	5.00	0.00	0.00 %
	2	11:07	5.00	5.00	0.00	0.00 %
	3	11:25	5.00	5.00	0.00	0.00 %
Mid-level	1	10:55	9.97	10.20	0.23	2.31 %
	2	11:13	9.97	10.20	0.23	2.31 %
	3	11:31	9.97	10.20	0.23	2.31 %

Low-level

Arithmetic Mean: 5.00

CGA Error: 0.00 %

Tank S/N CC14789
Tank Expiration Date 7/25/2025

Mid-Level

Arithmetic Mean: 10.20

CGA Error: 2.31 %

Tank S/N CC400438
Tank Expiration Date 8/16/2025

CGA Report

11/14/2018 - 11/14/2018

Date	Parameter	Run#	Timestamp	Type	Expected	Measured	Low Diff	-------	Mid Diff	-------
11/14/2018										
	O2 DRY, %	1	10:49:12	QTR_LOW	5.0	5.0	0.0			
	O2 DRY, %	1	10:55:12	QTR_MID	10.0	10.2			0.2	
	O2 DRY, %	2	11:07:13	QTR_LOW	5.0	5.0	0.0			
	O2 DRY, %	2	11:13:13	QTR_MID	10.0	10.2			0.2	
	O2 DRY, %	3	11:25:13	QTR_LOW	5.0	5.0	0.0			
	O2 DRY, %	3	11:31:13	QTR_MID	10.0	10.2			0.2	

Arithmetic Mean of Quarterly Low : 5.0
Linearity Error of Quarterly Low : 0.2
Calibration Tolerance: 15.0

Arithmetic Mean of Quarterly Mid : 10.2
Linearity Error of Quarterly Mid : 2.3
Calibration Tolerance: 15.0

Calibration Result : Pass

CEMS Type : Full Extractive
Manufacturer: Brand Gaus
Model Number : 4705
Serial Number: 11400
Monitor Certification Date:

Tested By : ______________________________

Date: ___________________________________

IV. Cylinder Gas Certification Sheets

Airgas.
an Air Liquide company

In Service 9/29/17

Airgas USA, LLC
12722 S. Wentworth Ave.
Chicago, IL 60628
Airgas.com

CERTIFICATE OF ANALYSIS

Grade of Product: EPA Protocol

Part Number:	E04NI84E15A0007	Reference Number:	54-124629354-1
Cylinder Number:	CC14789	Cylinder Volume:	150.4 CF
Laboratory:	124 - Chicago - IL	Cylinder Pressure:	2015 PSIG
PGVP Number:	B12017	Valve Outlet:	660
Gas Code:	CO2,O2,SO2,BALN	Certification Date:	Jul 25, 2017

Expiration Date: Jul 25, 2025

Certification performed in accordance with "EPA Traceability Protocol for Assay and Certification of Gaseous Calibration Standards (May 2012)" document EPA 600/R-12/531, using the assay procedures listed. Analytical Methodology does not require correction for analytical interference. This cylinder has a total analytical uncertainty as stated below with a confidence level of 95%. There are no significant impurities which affect the use of this calibration mixture. All concentrations are on a volume/volume basis unless otherwise noted.

Do Not Use This Cylinder below 100 psig, i.e. 0.7 megapascals.

ANALYTICAL RESULTS

Component	Requested Concentration	Actual Concentration	Protocol Method	Total Relative Uncertainty	Assay Dates
[redacted]	175.0 PPM	[redacted]	G1	+/- 1.0% NIST Traceable	07/17/2017, 07/25/2017
[redacted]	5.000 %	[redacted]	G1	+/- 1.0% NIST Traceable	07/18/2017
CARBON DIOXIDE	10.00 %	10.00 %	G1	+/- 0.9% NIST Traceable	07/17/2017
NITROGEN	Balance				

CALIBRATION STANDARDS

Type	Lot ID	Cylinder No	Concentration	Uncertainty	Expiration Date
NTRM	16060140	CC437515	515.2 PPM SULFUR DIOXIDE/NITROGEN	+/- 0.8%	Nov 16, 2021
NTRM	11060719	CC338460	4.861 % OXYGEN/NITROGEN	+/- 0.4%	Dec 13, 2022
NTRM	13060635	CC413759	13.359 % CARBON DIOXIDE/NITROGEN	+/- 0.6%	May 09, 2019

ANALYTICAL EQUIPMENT

Instrument/Make/Model	Analytical Principle	Last Multipoint Calibration
Nicolet 6700 AHR0801332	FTIR	Jun 21, 2017
O2-1 HORIBA MPA-510 3VUYL9NR	Paramagnetic	Jul 17, 2017
Nicolet 6700 AHR0801332	FTIR	Jul 21, 2017

Triad Data Available Upon Request

Approved for Release

In Service 9/29/17

Airgas.
an Air Liquide company

Airgas Specialty Gases
Airgas USA, LLC
12722 S. Wentworth Ave.
Chicago, IL 60628
Airgas.com

CERTIFICATE OF ANALYSIS
Grade of Product: EPA Protocol

Part Number:	E02NI90E15A0228	Reference Number:	54-400967311-1
Cylinder Number:	CC400438	Cylinder Volume:	145.2 CF
Laboratory:	124 - Chicago (SAP) - IL	Cylinder Pressure:	2015 PSIG
PGVP Number:	B12017	Valve Outlet:	590
Gas Code:	O2,BALN	Certification Date:	Aug 16, 2017

Expiration Date: Aug 16, 2025

Certification performed in accordance with "EPA Traceability Protocol for Assay and Certification of Gaseous Calibration Standards (May 2012)" document EPA 600/R-12/531, using the assay procedures listed. Analytical Methodology does not require correction for analytical interference. This cylinder has a total analytical uncertainty as stated below with a confidence level of 95%. There are no significant impurities which affect the use of this calibration mixture. All concentrations are on a volume/volume basis unless otherwise noted.
Do Not Use This Cylinder below 100 psig, i.e. 0.7 megapascals.

ANALYTICAL RESULTS

Component	Requested Concentration	Actual Concentration	Protocol Method	Total Relative Uncertainty	Assay Dates
[redacted]	10.00 %	[redacted]	G1	+/- 1% NIST Traceable	08/16/2017
NITROGEN	Balance				

CALIBRATION STANDARDS

Type	Lot ID	Cylinder No	Concentration	Uncertainty	Expiration Date
NTRM	06120102	CC195613	9.898 % OXYGEN/NITROGEN	+/- 0.7%	Jul 26, 2018

ANALYTICAL EQUIPMENT

Instrument/Make/Model	Analytical Principle	Last Multipoint Calibration
O2-1 HORIBA MPA-510 3VUYL9NR	Paramagnetic	Jul 17, 2017

Triad Data Available Upon Request

Approved for Release

Airgas
an Air Liquide company

Airgas Specialty Gases
Airgas USA, LLC
12722 S. Wentworth Ave.
Chicago, IL 60628
Airgas.com

CERTIFICATE OF ANALYSIS

Grade of Product: EPA Protocol

Part Number:	E03NI89E15A0052	Reference Number:	54-124629358-1
Cylinder Number:	CC89122	Cylinder Volume:	149.9 CF
Laboratory:	124 - Chicago (SAP) - IL	Cylinder Pressure:	2015 PSIG
PGVP Number:	B12017	Valve Outlet:	660
Gas Code:	CO2,SO2,BALN	Certification Date:	Jul 17, 2017

Expiration Date: Jul 17, 2025

Certification performed in accordance with "EPA Traceability Protocol for Assay and Certification of Gaseous Calibration Standards (May 2012)" document EPA 600/R-12/531, using the assay procedures listed. Analytical Methodology does not require correction for analytical interference. This cylinder has a total analytical uncertainty as stated below with a confidence level of 95%. There are no significant impurities which affect the use of this calibration mixture. All concentrations are on a volume/volume basis unless otherwise noted.

Do Not Use This Cylinder below 100 psig, i.e. 0.7 megapascals.

ANALYTICAL RESULTS

Component	Requested Concentration	Actual Concentration	Protocol Method	Total Relative Uncertainty	Assay Dates
SULFUR DIOXIDE	385.0 PPM	387.3 PPM	G1	+/- 0.8% NIST Traceable	07/17/2017
CARBON DIOXIDE	10.00 %	9.994 %	G1	+/- 1.0% NIST Traceable	07/17/2017
NITROGEN	Balance			-	

CALIBRATION STANDARDS

Type	Lot ID	Cylinder No	Concentration	Uncertainty	Expiration Date
NTRM	16060140	CC437515	515.2 PPM SULFUR DIOXIDE/NITROGEN	+/- 0.8%	Nov 16, 2021
NTRM	13060635	CC413759	13.359 % CARBON DIOXIDE/NITROGEN	+/- 0.6%	May 09, 2019

ANALYTICAL EQUIPMENT

Instrument/Make/Model	Analytical Principle	Last Multipoint Calibration
Nicolet 6700 AHR0801332	FTIR	Jun 21, 2017
Nicolet 6700 AHR0801332	FTIR	Jun 21, 2017

Triad Data Available Upon Request

Signature on file

Approved for Release

OPACITY PERFORMANCE AUDIT

FOR

Primary Energy

E. Chicago, IN

Unit: Stack 201

MONITORING SOLUTIONS, INC.
MODEL: DURAG D-R 290 COMS

Fourth (4th) Quarter Results
2018

Audit Completed On: 11/16/2018

PREPARED BY:

Monitoring Solutions
Leaders in Environmental Monitoring Systems & Services

TABLE OF CONTENTS

I. Introduction

Monitoring Solutions, Inc. was contracted to conduct an opacity performance audit on a Durag Model D-R 290 opacity system.

Client: Primary Energy
City, State: E. Chicago, IN
Auditor: Dan Bowles
Audit Date: 11/16/2018

The performance testing consists of:

1. Zero and Span Check
2. Zero Compensation Check
3. Optical Alignment Check
4. Calibration Error Check
5. Annual Zero Alignment (When required)

All raw data, calculated data and final summary are presented. The results indicate compliance for all specifications. Testing was performed as per 40CFR60 Appendix F and 40CFR60 Appendix B, PS1 (Where Applicable).

Annual "Zero Alignment" check performed this quarter:

YES: X NO: ______ ERROR: N/A

Summary of Calibration Error Check

Filter :	Low	Mid	High
Percent of Error:	0.30	0.30	0.18
	PASS	PASS	PASS

Reviewed by: Ethan Lee

Date: 12/14/2018

Revision: March 2016

**PERFORMANCE AUDIT PROCEDURES FOR THE
MONITORING SOLUTIONS, INC. OPACITY MONITOR**

II. Monitoring Solutions, Inc. Durag Model D-R 290

The instrument is manufactured by the Durag Corporation and distributed and serviced by Monitoring Solutions, Inc.

A. COMS Description

The Monitoring Solutions, Inc. D-R 290 opacity monitoring system consists of four major components: the Transmissometer, the terminal control box, the air-purging system and the remote control unit and data acquisition equipment. The Transmissometer component consists of an optical transmitter/receiver (transceiver) unit mounted on one side of a stack or duct and a retro reflector unit mounted on the opposite side. The transceiver unit contains the light source, the photodiode detector, and the associated electronics. The transceiver uses a single-lamp, single detector system to determine effluent opacity. A LED light source is modulated electronically at 2 KHz to eliminate any ambient light interference. The modulated beam is configured to alternately produce reference and measurement signals so that the effects of variations in the optical and electronic components of the COMS are minimized.

In a single display configuration, an AW unit is mounted in a blue housing next to the transceiver location. In a dual display configuration, an AZ unit is mounted in the blue housing next to the transceiver location and an AW is mounted in a remote location, typically, a control room. The AZ and the AW communicate via an RS 422 cable. The AZ unit provides an on stack readout and can be used as a diagnostic tool. In either configuration, only the AW provides the signals to the final recording device.

The air purging system serves a threefold purpose: 1) it provides an air window to keep exposed optical surfaces clean; 2) it protects the optical surfaces from condensation of stack gas moisture; and 3) it minimizes thermal conduction from the stack to the instrument. A standard installation has one air-purging system for each the transceiver and the retro reflector units.

The opacity monitor measures the amount of light transmitted through the effluent from the transceiver to the retro reflector and back again. The control unit uses the effluent transmittance to calculate the optical density of the effluent at the monitor location, or the “path” optical density. In order to provide stack exit opacity data, the path optical density must be corrected. The correction factor is expressed as the ratio of the stack exit inside diameter to the inside diameter of the stack at the Transmissometer location. This ratio is called the “stack correction factor” (SCF) by Monitoring Solutions, Inc. The following equations illustrate the relationship between this ratio, path optical density, and stack exit opacity.

Calculation of "Stack Correction Factor"

	L_x / L_t	=	stack correction factor
where:	L_x	=	stack exit inside diameter (in)
	L_t	=	the stack inside diameter (or the duct width) at the monitor location (in).
	OP_x	=	$1-(1-\frac{Opacity}{100})^{correction\ factor}$
	OP_x	=	stack exit opacity (%)

B. **Performance Audit Procedures**

1. **Preliminary Data**

a. Obtain the stack exit inside diameter (in feet) and the stack inside diameter at the monitor location (in feet). Record these values in Blanks 1 and 2 of the Monitoring Solutions, Inc. D-R 290 Performance Audit Data Sheet.

Note: Effluent handling system dimensions may be acquired from the following sources listed in descending order of reliability: 1) physical measurements, 2) construction drawings, 3) opacity monitor installation/certification documents, and 4) source personnel recollections.

b. Calculate the stack correction factor (SCF) by dividing the value in Blank 1 by the value in Blank 2. Record the result in Blank 3.

c. Record the source-cited Stack Correction Factor (SCF) in Blank 4.

Note: The stack correction factor (SCF) is preset by the manufacturer using information supplied by the source. The value recorded in Blank 4 should be the value source personnel agree should be set inside the monitor.

d. Obtain the reference zero and span calibration values. Record these values in Blank 5 and Blank 6, respectively.

Note: The reference zero and span calibration values may not be the same as the values recorded during instrument installation and/or certification. The zero and span values recorded in Blank 5 and Blank 6 should be the reference values recorded during the most recent clear-path calibration of the CEMS.

2. Error Checks

The following steps describe the error codes for the Monitoring Solutions, Inc. D-R 290 remote control unit. The audit can continue with the error codes shown below being present, provided the source has been informed of the fault conditions. All other error codes must be corrected prior to audit.

Error code 100 = Transceiver blower fault
Error code 200 = Transceiver filter plugged
Error code 300 = Reflector blower fault
Error code 400 = Reflector filter plugged

Note: If a fault is active, an error code will be displayed on the stack mounted display and on the remote display. An explanation of the error codes can be found in the manual.

3. Instrument Range Check

a. Check the COMS measurement range by pressing the MOD button (the LED on the button will light up) and using the PLUS button to cycle through the displays.

b. Record the instrument range in Blank 11.

4. Reference Signal, Zero and Span Checks

a. Initiate the calibration cycle by pressing the arrow and plus buttons simultaneously and holding for approximately 5 seconds.

Note: The opacity monitor will automatically cycle through the internal zero (zero point check), external zero (window check), span and stack taper ratio modes. Approximately 6 minutes for a complete cycle.

b. Record the milliamp value shown for the internal zero (zero point check) displayed on the control panel display in Blank 12.

Note: The internal zero checks the instrument reference signal (Zero Point Check). Since the instrument provides a full scale output of 4 to 20 milliamps, a value of 4 milliamps displayed on the control unit display represents a zero condition. After 1 ½ minutes in the internal zero mode, the monitor will automatically switch to the external zero mode (Window Check).

c. Record the milliamp value shown for the external zero (window check) displayed on the control panel in Blank 13. Also record the external zero value (in percent opacity) displayed on the opacity data recorder in Blank 14.
(Continued on next page)

Note: During the zero calibration check, the zero mirror is moved into the path of the measurement beam by a servomotor. The zero mechanism is designed to present the transceiver with a simulated clear-path condition. The daily zero check does not test the actual clear-path zero, nor does it provide a check of cross-stack parameters such as the optical alignment of the Transmissometer or drift in the reflectance of the retro reflector. The actual clear-path zero can only be checked during clear-stack or off-stack calibration of the CEMS. In addition to simulating the instrument clear-path zero, the zero mechanism allows the amount of dust on the transceiver optics (primary lens and zero mirror) to be quantified. After 1 ½ minutes in the external zero mode, the CEMS will automatically enter the span mode.

d. Record in Blank 15 the span value (in milliamps) displayed on the control panel display. Also record the span value (in percent opacity) displayed on the data recorder in Blank 16. Go to the Transmissometer location.

Note: During the span calibration check, a servomotor moves an internal span filter into the path of the measurement beam while the zero mirror is in place. The span mechanism is designed to provide an indication of the upscale accuracy of the CEMS relative to the simulated clear-path zero. Note: The opacity monitor display will output its stack correction factor (SCF) for 1 ½ minutes when the span portion of the calibration cycle is completed. The CEMS automatically returns to the measurement mode when the SCF portion of the calibration cycle is complete.

5. Reflector Dust Accumulation Check.

a. Record the effluent opacity prior to cleaning the retroreflector optics in Blank 17.

b. Open the reflector housing, inspect and clean the retroreflector optics, and close the housing.

c. Record the post-cleaning effluent opacity in Blank 18. Go to the transceiver location.

6. Transceiver Dust Accumulation Check.

a. Record the pre-cleaning effluent opacity in Blank 19.

b. Open the transceiver, clean the optics (primary window and zero mirror) and close the transceiver.

c. Record the post-cleaning effluent opacity in Blank 20.

7. Alignment Check

a. Determine the monitor alignment by looking through the alignment port of the side of the transceiver.

b. Observe whether the image is centered in the cross hairs and record this information (YES or NO) in Blank 21.

8. Zero Compensation Check

The Durag 290 provides internal compensation for window contamination. This compensation value can be determined by performing the Window Check. This compensation cannot be disabled for testing. Remove internal compensation as follows: Clean the transceiver window and the zero mirror lens. Verify the window check value is at zero so no compensation is applied to the quarterly audit. Enter the Filter Audit Mode and verify the starting Durag opacity value is zero percent. **NOTE:** This process must be completed prior to the Calibration Error Check.

9. Zero Alignment Error Check

The Zero Alignment Error Check is performed one time each year. This check utilizes Durag's Clear Path Procedure. This procedure verifies the “measuring” zero point of the unit in a known clear path setup. The Transceiver and reflector are removed from their installation and set up on stands in a clean, dust free environment. The stands are set at the same distance as the installation location. Without performing any adjustments, the measuring zero is compared to the simulated zero - or - Window Check. The difference between the measuring zero and the simulated zero, must NOT exceed 2% opacity.

Verify the Zero Compensation Check has been performed. Since the zero compensation function cannot be disabled for the zero alignment check, the optics must be cleaned and a manual calibration performed. This will set the internal compensation value to 0.0%. This MUST be accomplished prior to the Zero Alignment Check.

Perform the following to document the "Zero Alignment Error":

a) Remove the Transceiver & Reflector from its current installation and setup on stands at the exact distance as their original location.

b) Perform the Zero Compensation Check and perform a manual calibration.

c) Record the Durag's response to the clear path zero in % opacity without any adjustment.

d) Activate the simulated zero (Window Check) and record the reading in % opacity without any adjustment.
(continued on next page)

e) The response difference between these two readings are recorded as the “zero alignment error”. The maximum allowable zero alignment error is 2%.

f) Adjust the simulated zero (window check) to read the same value in % opacity as the clear path zero.

10. Calibration Error Check

The calibration error check is performed using three neutral density filters. Performing the calibration error check on-stack using the filters determines the linearity of the instrument response relative to the current clear-path zero setting. This calibration error check does not determine the accuracy of the actual instrument clear-path zero or the status of any cross-stack parameters. A true calibration check is performed by moving the on-stack components to a location with minimal ambient opacity, making sure that the proper path length and alignments are attained, and then placing the calibration filters in the measurement path.

a. Put the monitor in Filter Audit mode.

b. Wait approximately three minutes or until a clear “zero” value has been recorded and displayed on the data recorder.

c. Record the audit filter serial numbers and opacity values in Blanks 22, 23, and 24.

d. Remove the filters from their protective covers, inspect and if necessary, clean them.

e. Insert the low range neutral density filter into the filter audit slot located in front of the heated lens.

f. Wait approximately three minutes or until a clear value has been recorded and displayed on the data recorder.

Note: The audit data should be taken from a data recording/reporting device that presents instantaneous opacity (or opacity data with the shortest available integration period).

g. Record the COMS response to the low range neutral density filter.

h. Remove the low range filter and insert the mid range neutral density filter.

i. Wait approximately three minutes and record the COMS response to the mid range neutral density filter.

j. Remove the mid range filter and insert the high range filter.

k. Wait approximately three minutes and record the COMS response to the high range neutral density filter.

(continued on next page)

l. Remove the high range filter.

m. * If applicable, wait approximately three minutes, and record the zero value.

n. Repeat steps (e) through (m) until a minimum of three opacity readings are obtained for each neutral density filter.

o. If six-minute integrated opacity data is required, repeat steps (e) through (m) once more, changing the waiting periods to 13 minutes.

p. Record the six-minute integrated data.

Note: In order to acquire valid six-minute averaged opacity data, each filter must remain in for at least two consecutive six-minute periods; the first period will be invalid because it was in progress when the filter was inserted. A waiting period of 13 minutes is recommended. You should have a "starting zero" reading and an "ending zero" reading.

q. When the calibration error check is complete, return the monitor to measuring mode. Close the transceiver head and the weather cover, and return to the COMS control unit.

11. Test Conclusion

a. Obtain a copy of the audit data from the data recorder.

b. Transcribe the calibration error response from the data recorder to Blanks 25 through 50 of the audit form and complete the audit data calculations.

C. Interpretation of Audit Results

This section is designed to help the auditor interpret the D-R 290 performance audit results.

Error codes / fault analysis

Error codes are typically associated with parameters that the monitor manufacturer feels are critical to COMS function, and to the collection of valid opacity data. The parameters associated with each of the error codes are found in the manufacturer's manual. With the exception of alarms that warn of elevated opacity levels (alarm or warning lamps), the error codes indicate that the COMS is not functioning properly. An error or failure indication will be represented by a "YES" in Blanks 7 - 10.

(continued on next page)

Stack Exit Correlation Error Check

The path length correction error in Blank 51 should be within +2%. This error exponentially affects the opacity readings, resulting in over - or - underestimation of the stack exit opacity. The most common error in computing the optical path length correction factor is the use of the flange-to-flange distance in place of the stack/duct inside diameter at the monitor location. This error will result in underestimation of the stack exit opacity and can be identified by comparing the monitor optical path length to the flange-to-flange distance; the flange-to-flange distance should be greater by approximately two to four feet

Control Panel Meter Error (Optional)

The accuracy of the control panel meter (AW) is important at sources using the meter during monitor adjustment and calibration. The accuracy of the control panel meter (Blank 52 and Blank 54) is determined by comparing the zero and span reference values to the panel meter output recorded during the COMS calibration check.

Note: Some installations utilize a different "Instrument Range Setting" than the normal 100% range. The panel meter span error must be corrected for the different range in order to provide an accurate error result. Use the following equation to calculate the span error corrected for "Instrument Range" (Blank 11):

Panel Meter span error in % opacity =

$$(((\text{Blank } 15 - 4) \div 16) \times \text{Blank } 11) - \text{Blank } 6$$

Zero and Span Checks

The D-R 290 internal zero or "zero point check" (Blank 12 should be set to indicate 0% opacity (equivalent to 3.7 - 4.3 mA). An external zero error or "window check" (Blank 53) greater than 4% opacity is usually due to excessive dust accumulation on the optical surfaces, electronic drift or an electronic/mechanical offset of the data recorder. Excessive dust on the optical surfaces sufficient to cause a significant zero error would be indicated by the difference in the internal and external zero values and/or window alarm. Instrument span error (Blank 55) may be caused by the same problem(s) that cause zero errors and may be identified in a similar fashion.

If the zero and span errors are due to a data recorder offset, both errors will be in the same direction and will be of the same magnitude

(continued on next page)

The external zero displayed on the control unit panel meter (AW) also indicates the level of dust accumulation on the zero retroreflector and transceiver measurement window. The difference between the internal and external zero responses should equal the amount of dust found on the transceiver optics (Blank 57). To convert the zero responses to a value that represents lens dusting in percent opacity, use the following equation.

Meter response in % opacity = 6.25 [(Blank 13) - (Blank 12)]

Optical Alignment Check

When the transceiver and retroreflector are misaligned, a portion of the measurement beam that should be returned to the measurement detector is misdirected, resulting in a positive bias in the data reported by the COMS. One of the most common causes of misalignment is vibration which may cause the on-stack components to shift slightly on the instrument mounting flanges. Another common cause of misalignment is thermal expansion and contraction of the structure on which the transmissometer is mounted. If the COMS is being audited while the unit is off-line (cold stack), the results of the alignment analysis may not be representative of the alignment of the instrument when the stack or duct is at normal operating temperature. When checking the alignment, the reflected light beam should be centered.

Zero Compensation Check

The Zero Compensation Check should be performed and documented as such in (Blank 21a).

Annual Zero Alignment Error Check

The Zero Alignment Error Check is performed once each year. It verifies that the enegy output from the simulated zero device (Window Check) is within 2% of the Clear Path reading. The values required for this check are documented in (Blank 21b). If the difference between the Clear Path Value and the Simulated Zero (Window Check) value differ by more than 2%, then the COMS unit is considered Out Of Control. If the difference is 2% or less, then the Window Check Value is adjusted to match the Clear Path value.

Optical Surface Dust Accumulation Check

The results of the dust accumulation check (Blank 58) should not exceed 4%. A dust accumulation value of more than 4% opacity indicates that the air flow of the purge system and/or the cleaning frequency of the optical surfaces are inadequate. When determining the optical surface dust accumulation, the auditor should note whether the effluent opacity is relatively stable (within +2% opacity) before and after cleaning the optical surfaces. If the effluent opacity is fluctuating by more that +2%, the dust accumulation analysis should be omitted.

(continued on next page)

Calibration Error

Calibration error results (Blanks 68, 69 and 70) in excess of +3% are indicative of a non-linear or miss calibrated instrument. However, the absolute calibration accuracy of the monitor can be determined only when the instrument clear-path zero value is known. If the zero and span data are out-of-specification, the calibration error data will often be biased in the direction of the zero and span errors. Even if the zero and span data indicate that the COMS is calibrated properly, the monitor may still be inaccurate due to error in the clear-path zero adjustment. The optimum calibration procedure involves using neutral density filters during clear-stack or off-stack COMS calibration. This procedure would establish both the absolute calibration accuracy and linearity of the COMS. If this procedure is impractical, and it is reasonable to assume that the clear-path zero is set correctly, the monitor’s calibration can be set using either the neutral density filters or the internal zero and span values.

Appendix A
COMS Audit Data Forms for the Durag Model D-R 290

AUDIT DATA SHEET
MONITORING SOLUTIONS DURAG D-R 290 COMS

Company:	Primary Energy	City, ST:	E. Chicago, IN
Unit ID:	Stack 201		
Auditor:	Dan Bowles	Representing:	Monitoring Solutions
Attendees:	N/A	Representing:	
Transceiver serial number:	1248342		
Reflector serial number:	1248145		
Remote serial number	1248283	COMS Flange to Flange distance (Feet / Inches):	226.125"
Date:	11/16/2018		

Preliminary Data

1 Inside diameter at Stack Exit = Lx	216.000	inches
2 Inside diameter at the Transmissometer location = Lt	216.000	inches
3 Calculated Stack Correction Factor (SCF) = Lx/Lt	1.000	
4 Source-cited Stack Correction Factor (SCF)	1.000	
5 Source-cited zero automatic calibration value (% opacity)	0.00	%
6 Source-cited span automatic calibration value (% opacity)	40.00	%

[START AT CONTROL UNIT / DATA RECORDER LOCATION]

(If required) [INSPECT DATA RECORDING SYSTEM AND MARK WITH "OPACITY AUDIT," AUDITOR'S NAME, AFFILIATION, DATE, SOURCE, PROCESS UNIT/STACK IDENTIFICATION, AND THE TIME OF DAY.]

Error codes / faults	YES - or - NO
7 Blower [Loss of purge air from blower - Error 100, 300]	NO
8 Filter [Air filter restriction - Error 200, 400]	NO
9 Window [Excessive dirt on transceiver window - Error 001]	NO
10 Fault [Additional CEMS fault has occurred. Note fault code on Opacity display and consult the instrument manual.]	NO

Instrument Range Check

11 Instrument range setting	100	%

Zero Check

12 Opacity Display - Internal zero value in "milliamps" (Zero Point Check)	4.00	mA
[Wait for 1½ minutes for automatic change to external zero mode.]		
13 Opacity Display - Zero calibration value in "milliamps" (Window Check)	4.00	mA
14 Opacity data recorder zero calibration value in "% Op" (Window Check)	0.00	mA
[Wait 1½ minutes for automatic change to span mode.]		

Span Check

15 Opacity Display - Span calibration value in "milliamps" (Span Check)	10.40	mA
16 Opacity data recorder span calibration value in "% Op" (Span Check)	40.00	%

[Go to reflector location.]

AUDIT DATA SHEET
MONITORING SOLUTIONS DURAG D-R 290 COMS

Reflector Dust Accumulation Check

17 Pre-cleaning effluent opacity (% Op) 0.0 %

[Inspect and clean optical surface.]

18 Post-cleaning effluent opacity (% Op) 0.0 %

[Go to transceiver location.]

Transceiver Dust Accumulation Check and Zero Compensation Check

19 Pre-cleaning effluent opacity (% Op) 0.0 %

[Inspect and clean optical window and zero mirror.]

20 Post-cleaning effluent opacity (% Op) 0.0 %

Optical Alignment Check

[LOOK THROUGH ALIGNMENT SIGHT AND DETERMINE IF BEAM IMAGE IS CENTERED.]

21 Is the image centered?

YES - or - NO
YES

Zero Compensation Check

21a Did you comply with the Zero Compensation Check?

YES - or - NO
YES

Annual Zero Alignment Error Check

21b Did you comply with the Annual Zero Alignment Error Check?

YES - or - NO
NO

Zero Alignment Error Check results (if applicable):

Clear Path Value % = N/A Window Check Value % = N/A Zero Alignment Error % = N/A

[Record audit filter data.]

Filter	Serial NO.	% Opacity	SCF%
22 LOW	VW72	18.20	18.20 %
23 MID	ZB12	27.20	27.20 %
24 HIGH	ZC32	43.90	43.90 %

[Remove the audit filters from the protective covers, inspect, and clean each filter]

[Set the unit up to display the initial zero. Wait 3 minutes to allow opacity data recorder to record initial zero]

[Insert a filter, wait approximately 3 minutes, and record the opacity value reported by the opacity data recorder. Repeat the process 5 times for each filter.]

[Read and transcribe final calibration error data from the opacity data recorder on the next page]

AUDIT DATA SHEET
MONITORING SOLUTIONS DURAG D-R 290 COMS

25 ZERO 0.00

	LOW		MID		HIGH		(If Required) ZERO
26	18.50	27	27.50	28	43.70	29	N/A
30	18.50	31	27.50	32	43.80	33	N/A
34	18.50	35	27.50	36	43.80	37	N/A
38	18.50	39	27.50	40	43.80	41	N/A
42	18.50	43	27.50	44	43.80	45	0.00

[Six-minute average data, if applicable.]

	ZERO		LOW		MID		HIGH		(If Required) ZERO
46	0.00	47	18.50	48	27.50	49	43.40	50	0.00

Reserved Area

Calculation of Audit Results

Stack Correction Factor correlation error (%):

1.000 1.000

51 $$\left[\frac{Blank\ 4 - Blank\ 3}{Blank\ 3}\right] \times 100$$ = 0.00

1.000

Zero Error (% Op.):

4.00 0.00

52 Opacity Display 6.25 * (Blank 13 - 4.0) - Blank 5 = 0.00 %

0.00 0.00

53 Opacity Data Recorder Blank 14 - Blank 5 = 0.00

AUDIT DATA SHEET
MONITORING SOLUTIONS DURAG D-R 290 COMS

Span Error (% Op.):

54	Opacity Display	10.40 / 100 / 40.00 (((Blank 15 - 4.0) ÷ 16) × Blank 11) - Blank 6	=	0.00 %
55	Opacity Data Recorder	40 / 40 Blank 16 - Blank 6	=	0.00

Optical Surface Dust Accumulation (% OP):

56	Retroreflector	0 / 0.0 Blank 17 - Blank 18	=	0.00 %
57	Transceiver	0 / 0 Blank 19 - Blank 20	=	0.00 %
58	Total	0 / 0 Blank 56 + Blank 57	=	0.00 %

Optical Path Length Correction (SCF)
Audit Filters Corrected for Path Length:

59 LOW: 18.20 1.000

$$1-(1-(\frac{Blank\ 22}{100})^{Blank\ 4})\ x\ 100$$

= 18.20 %

60 MID: 27.20 1.000

$$1-(1-(\frac{Blank\ 23}{100})^{Blank\ 4})\ x\ 100$$

= 27.20 %

61 HIGH 43.90 1.000

$$1-(1-(\frac{Blank\ 24}{100})^{Blank\ 4})\ x\ 100$$

= 43.90 %

AUDIT DATA SHEET
MONITORING SOLUTIONS DURAG D-R 290 COMS

Auditor: Dan Bowles Date: 11/16/18
Source: Primary Energy Unit: Stack 201

PARAMETER			Blank No.	Audit Results	Specifications
Error Codes/Faults					
Blower failure			7	NO	NO
Filter Blockage			8	NO	NO
Window			9	NO	NO
Fault			10	NO	NO
SCF Correlation Error			51	0.00	+/- 2% Op
Internal Zero Error	Display		52	0.00	+/- 4% Op
	Data		53	0.00	+/- 4% Op
Internal Span Error	Display		54	0.00	+/- 4% Op
	Data		55	0.00	+/- 4% Op
Optical Alignment Analysis			21	YES	YES = Centered
Zero Compensation Check			21a	YES	YES = Complied With
Zero Alignment Error			21b	N/A	≤ 2% Op
Optical Surface Dust Accumulation					
Retroreflector			56	0.00	≤ 2% Op
Transceiver			57	0.00	≤ 2% Op
Total			58	0.00	≤ 4% Op
Calibration Error Analysis					
Arithmetic Mean Difference					
	LOW		62	0.30	
			71a	0.30	
	MID		63	0.30	
			72a	0.30	
	HIGH		64	-0.12	
			73a	-0.50	
Confidence Coeffecient					
			65	0.00	
			66	0.00	
			67	0.06	
Calibration Error					
			68	0.30	≤ 3% Op
			69	0.30	≤ 3% Op
			70	0.18	≤ 3% Op

Revision: March, 2016

OPACITY LOW FILTER AUDIT
Accuracy Determination

Primary Energy | E. Chicago, IN | Stack 201 | 11/16/2018

LOW FILTER RUN	Opacity Output from Recording Device	Audit Filter Value Corrected for Path Length (SCF)	(FILTER-MONITOR) Difference	Difference^2
		RM	**(X_i)**	**X_i^2**
1	18.50	18.20	0.30	0.0900
2	18.50	18.20	0.30	0.0900
3	18.50	18.20	0.30	0.0900
4	18.50	18.20	0.30	0.0900
5	18.50	18.20	0.30	0.0900

n = 5
t(0.975) = 2.776

Mean Ref. Method Value	**18.2000**	***RM***
Sum of Differences	**1.5000**	***Xi***
Arithmetic Mean Difference	**0.3000**	***Xi ave***
Sum of Differences Squared	**0.4500**	***Xi^2***
Standard Deviation	**0.0000**	***sd***
2.5% Error Conf.Coef	**0.0000**	***CC***
Calibration Error	**0.3000**	***percent***

OPACITY MID FILTER AUDIT
Accuracy Determination

Primary Energy | E. Chicago, IN | Stack 201 | 11/16/2018

MID FILTER RUN	Opacity Output from Recording Device	Audit Filter Value Corrected for Path Length (SCF)	(FILTER-MONITOR) Difference	Difference^2
		RM	(X_i)	X_i^2
1	27.50	27.20	0.30	0.0900
2	27.50	27.20	0.30	0.0900
3	27.50	27.20	0.30	0.0900
4	27.50	27.20	0.30	0.0900
5	27.50	27.20	0.30	0.0900

n = 5

t(0.975) = 2.776

Mean Ref. Method Value	**27.2000**	***RM***
Sum of Differences	**1.5000**	***Xi***
Arithmetic Mean Difference	**0.3000**	***Xi ave***
Sum of Differences Squared	**0.4500**	***Xi^2***
Standard Deviation	**0.0000**	***sd***
2.5% Error Conf.Coef	**0.0000**	***CC***
Calibration Error	**0.3000**	***percent***

OPACITY HIGH FILTER AUDIT

Accuracy Determination

Primary Energy | E. Chicago, IN | Stack 201 | 11/16/2018

HIGH FILTER RUN	Opacity Output from Recording Device	Audit Filter Value Corrected for Path Length (SCF)	(FILTER-MONITOR) Difference	Difference^2
		RM	(X_i)	X_i^2
1	43.70	43.90	-0.20	0.0400
2	43.80	43.90	-0.10	0.0100
3	43.80	43.90	-0.10	0.0100
4	43.80	43.90	-0.10	0.0100
5	43.80	43.90	-0.10	0.0100

n = 5

t(0.975) = 2.776

Mean Ref. Method Value	**43.9000**	***RM***
Sum of Differences	**-0.6000**	***Xi***
Arithmetic Mean Difference	**-0.1200**	***Xi ave***
Sum of Differences Squared	**0.0800**	***Xi^2***
Standard Deviation	**0.0447**	***sd***
2.5% Error Conf.Coef	**0.0555**	***CC***
Calibration Error	**0.1755**	***percent***

11/16/2018 OPACITY, %

09:34

09:34:00	0.0	MOS
09:34:02	0.0	MOS
09:34:04	0.0	MOS
09:34:06	0.0	MOS
09:34:08	0.0	MOS
09:34:10	0.0	MOS
09:34:12	0.0	MOS
09:34:14	0.0	MOS
09:34:16	0.0	MOS
09:34:18	0.0	MOS
09:34:20	0.0	MOS
09:34:22	0.0	MOS
09:34:24	0.0	MOS
09:34:26	0.0	MOS
09:34:28	0.0	MOS
09:34:30	3.2	MOS
09:34:32	9.1	MOS
09:34:34	13.7	MOS
09:34:36	18.3	MOS
09:34:38	18.5	MOS
09:34:40	18.5	MOS
09:34:42	18.5	MOS
09:34:44	18.5	MOS
09:34:46	18.5	MOS
09:34:48	18.5	MOS
09:34:50	18.5	MOS
09:34:52	18.5	MOS
09:34:54	16.3	MOS
09:34:56	18.6	MOS
09:34:58	20.8	MOS

Status Code Definitions

MOS = MONITOR OUT OF SERVICE

11/16/2018 OPACITY, %

09:35

09:35:00	23.1	MOS
09:35:02	27.5	MOS
09:35:04	27.5	MOS
09:35:07	27.5	MOS
09:35:09	27.5	MOS
09:35:11	27.5	MOS
09:35:13	27.5	MOS
09:35:15	27.5	MOS
09:35:17	27.5	MOS
09:35:19	26.3	MOS
09:35:21	24.3	MOS
09:35:23	28.4	MOS
09:35:25	32.4	MOS
09:35:27	37.7	MOS
09:35:29	43.7	MOS
09:35:31	43.7	MOS
09:35:33	43.7	MOS
09:35:35	43.8	MOS
09:35:37	43.8	MOS
09:35:39	43.8	MOS
09:35:41	43.8	MOS
09:35:43	43.8	MOS
09:35:45	43.8	MOS
09:35:47	36.3	MOS
09:35:49	30.0	MOS
09:35:51	25.0	MOS
09:35:53	19.0	MOS
09:35:55	18.5	MOS
09:35:57	18.5	MOS
09:35:59	18.5	MOS

Status Code Definitions

MOS = MONITOR OUT OF SERVICE

11/16/2018 OPACITY, %

09:36

09:36:01	18.5	MOS
09:36:03	18.5	MOS
09:36:05	18.5	MOS
09:36:07	18.5	MOS
09:36:09	18.5	MOS
09:36:11	18.5	MOS
09:36:13	15.4	MOS
09:36:15	17.6	MOS
09:36:17	19.8	MOS
09:36:19	22.1	MOS
09:36:21	27.4	MOS
09:36:23	27.5	MOS
09:36:25	27.5	MOS
09:36:27	27.5	MOS
09:36:29	27.5	MOS
09:36:31	27.5	MOS
09:36:33	27.5	MOS
09:36:35	27.5	MOS
09:36:37	27.5	MOS
09:36:39	27.5	MOS
09:36:41	25.8	MOS
09:36:43	21.0	MOS
09:36:45	25.0	MOS
09:36:47	29.1	MOS
09:36:49	34.8	MOS
09:36:51	43.8	MOS
09:36:53	43.8	MOS
09:36:55	43.8	MOS
09:36:57	43.8	MOS
09:36:59	43.7	MOS

Status Code Definitions

MOS = MONITOR OUT OF SERVICE

Scans Report

11/16/2018 OPACITY, %

09:37

09:37:01	43.7	MOS
09:37:03	43.7	MOS
09:37:05	43.8	MOS
09:37:07	43.8	MOS
09:37:09	43.8	MOS
09:37:11	43.8	MOS
09:37:13	43.8	MOS
09:37:15	43.7	MOS
09:37:17	42.1	MOS
09:37:19	30.8	MOS
09:37:21	24.5	MOS
09:37:23	18.2	MOS
09:37:25	16.3	MOS
09:37:27	18.5	MOS
09:37:29	18.5	MOS
09:37:31	18.5	MOS
09:37:33	18.6	MOS
09:37:35	18.6	MOS
09:37:37	18.6	MOS
09:37:39	18.6	MOS
09:37:41	18.6	MOS
09:37:43	18.5	MOS
09:37:45	19.1	MOS
09:37:48	21.5	MOS
09:37:50	23.6	MOS
09:37:52	25.8	MOS
09:37:54	27.5	MOS
09:37:56	27.5	MOS
09:37:58	27.5	MOS

Status Code Definitions

MOS = MONITOR OUT OF SERVICE

11/16/2018 OPACITY, %

09:38

09:38:00	27.5	MOS
09:38:02	21.2	MOS
09:38:04	24.0	MOS
09:38:06	27.4	MOS
09:38:08	31.1	MOS
09:38:10	39.8	MOS
09:38:12	43.8	MOS
09:38:14	43.8	MOS
09:38:16	43.7	MOS
09:38:18	43.7	MOS
09:38:20	43.7	MOS
09:38:22	43.7	MOS
09:38:24	43.7	MOS
09:38:26	43.8	MOS
09:38:28	43.8	MOS
09:38:30	43.8	MOS
09:38:32	35.2	MOS
09:38:34	28.9	MOS
09:38:36	22.6	MOS
09:38:38	16.2	MOS
09:38:40	18.5	MOS
09:38:42	18.5	MOS
09:38:44	18.5	MOS
09:38:46	18.5	MOS
09:38:48	18.5	MOS
09:38:50	18.5	MOS
09:38:52	18.5	MOS
09:38:54	18.5	MOS
09:38:56	18.5	MOS
09:38:58	18.5	MOS

Status Code Definitions

MOS = MONITOR OUT OF SERVICE

11/16/2018 OPACITY, %

09:39

09:39:00	18.5	MOS
09:39:02	18.5	MOS
09:39:04	15.0	MOS
09:39:06	17.2	MOS
09:39:08	19.5	MOS
09:39:10	21.7	MOS
09:39:12	27.5	MOS
09:39:14	27.5	MOS
09:39:16	27.5	MOS
09:39:18	27.5	MOS
09:39:20	27.5	MOS
09:39:22	27.5	MOS
09:39:24	25.9	MOS
09:39:26	22.6	MOS
09:39:28	26.7	MOS
09:39:30	30.7	MOS
09:39:32	35.6	MOS
09:39:34	43.8	MOS
09:39:36	43.8	MOS
09:39:38	43.8	MOS
09:39:40	43.8	MOS
09:39:42	43.8	MOS
09:39:44	43.8	MOS
09:39:46	43.8	MOS
09:39:48	43.8	MOS
09:39:50	43.8	MOS
09:39:52	43.8	MOS
09:39:54	41.1	MOS
09:39:56	32.4	MOS
09:39:58	26.1	MOS

Status Code Definitions

MOS = MONITOR OUT OF SERVICE

11/16/2018 OPACITY, %

09:40

09:40:00	19.8	MOS
09:40:02	16.2	MOS
09:40:04	18.5	MOS
09:40:06	18.5	MOS
09:40:08	18.5	MOS
09:40:10	18.5	MOS
09:40:12	18.5	MOS
09:40:14	18.5	MOS
09:40:16	18.5	MOS
09:40:18	18.5	MOS
09:40:20	18.5	MOS
09:40:22	18.5	MOS
09:40:24	15.4	MOS
09:40:26	16.0	MOS
09:40:28	18.3	MOS
09:40:31	20.5	MOS
09:40:33	25.8	MOS
09:40:35	27.5	MOS
09:40:37	27.5	MOS
09:40:39	27.5	MOS
09:40:41	27.5	MOS
09:40:43	27.5	MOS
09:40:45	27.5	MOS
09:40:47	27.5	MOS
09:40:49	27.5	MOS
09:40:51	27.5	MOS
09:40:53	27.5	MOS
09:40:55	27.5	MOS
09:40:57	27.5	MOS
09:40:59	27.5	MOS

Status Code Definitions

MOS = MONITOR OUT OF SERVICE

Scans Report

11/16/2018 OPACITY, %

09:41

09:41:01	22.6	MOS
09:41:03	23.7	MOS
09:41:05	28.8	MOS
09:41:07	32.9	MOS
09:41:09	43.6	MOS
09:41:11	43.8	MOS
09:41:13	43.8	MOS
09:41:15	43.8	MOS
09:41:17	43.8	MOS
09:41:19	43.8	MOS
09:41:21	43.8	MOS
09:41:23	43.8	MOS
09:41:25	43.8	MOS
09:41:27	43.8	MOS
09:41:29	38.5	MOS
09:41:31	31.9	MOS
09:41:33	25.6	MOS
09:41:35	19.2	MOS
09:41:37	18.2	MOS
09:41:39	18.5	MOS
09:41:41	18.5	MOS
09:41:43	18.5	MOS
09:41:45	19.0	MOS
09:41:47	20.8	MOS
09:41:49	23.0	MOS
09:41:51	25.2	MOS
09:41:53	27.5	MOS
09:41:55	27.5	MOS
09:41:57	22.4	MOS
09:41:59	25.3	MOS

Status Code Definitions

MOS = MONITOR OUT OF SERVICE

11/16/2018 OPACITY, %

09:42

09:42:01	30.4	MOS
09:42:03	34.5	MOS
09:42:05	42.8	MOS
09:42:07	43.8	MOS
09:42:09	43.8	MOS
09:42:11	43.8	MOS
09:42:13	43.8	MOS
09:42:15	43.8	MOS
09:42:17	43.8	MOS

Status Code Definitions

MOS = MONITOR OUT OF SERVICE

OPACITY FILTER AUDIT
*** 6-minute Averages ***
Accuracy Determination

Primary Energy | E. Chicago, IN | Stack 201 | 11/16/2018

6 Minute Averages	Opacity Output from Recording Device	Audit Filter Value Corrected for Path Length (SCF)	(FILTER-MONITOR) Difference	Opacity Error
		RM	(Xi)	
ZERO	0.00	0.00	0.00	**0.00**
LOW	18.50	18.20	0.30	**0.30**
MID	27.50	27.20	0.30	**0.30**
HIGH	43.40	43.90	-0.50	**0.50**
ZERO	0.00	0.00	0.00	**0.00**

Opacity Report

11/16/2018 - 11/16/2018

11/16/2018

Created on : Nov 16, 2018 10:54:05

STACK 201

Hour	Opac, % Minutes 0 - 5	Opac, % Minutes 6 - 11	Opac, % Minutes 12 - 17	Opac, % Minutes 18 - 23	Opac, % Minutes 24 - 29	Opac, % Minutes 30 - 35	Opac, % Minutes 36 - 41	Opac, % Minutes 42 - 47	Opac, % Minutes 48 - 53	Opac, % Minutes 54 - 59
0	0.4 SVC	0.4 SVC	0.4 SVC	0.4 SVC	0.4 SVC	0.4 SVC	0.4 SVC	0.4 SVC	0.4 SVC	0.4 SVC
1	0.4 SVC	0.4 SVC	0.4 SVC	0.4 SVC	0.4 SVC	0.4 SVC	0.4 SVC	0.4 SVC	0.4 SVC	0.4 SVC
2	0.4 SVC	0.4 SVC	0.4 SVC	0.4 SVC	0.4 SVC	0.4 SVC	0.4 SVC	0.4 SVC	0.4 SVC	0.4 SVC
3	0.4 SVC	0.4 SVC	0.4 SVC	0.4 SVC	0.4 SVC	0.4 SVC	0.4 SVC	0.4 SVC	0.4 SVC	0.4 SVC
4	0.4 SVC	0.4 SVC	0.4 SVC	0.4 SVC	0.4 SVC	0.4 SVC	0.4 SVC	0.4 SVC	0.4 SVC	0.4 SVC
5	0.4 SVC	0.4 SVC	0.4 SVC	0.4 SVC	0.4 SVC	0.4 SVC	0.4 SVC	0.4 SVC	0.4 SVC	0.4 SVC
6	0.4 SVC	0.4 SVC	0.4 SVC	0.4 NSA	0.4 SVC	0.4 SVC	0.4 SVC	0.4 SVC	0.4 SVC	0.4 SVC
7	0.4 SVC	0.4 SVC	0.4 SVC	0.4 SVC	0.4 SVC	0.4 SVC	0.4 SVC	0.4 SVC	0.4 SVC	0.4 SVC
8	0.4 SVC	0.4 SVC	0.4 SVC	0.4 SVC	0.4 SVC	0.4 SVC	0.4 SVC	0.4 SVC	0.4 SVC	0.4 SVC
9	0.4 SVC	1.2 MOS	0.0 MOS	8.4 MOS	30.8 MOS	12.4 MOS	28.3 MOS	3.9 MOS	0.0 MOS	12.1 MOS
10	18.5 MOS	22.6 MOS	27.5 MOS	31.0 MOS	43.8 MOS	43.4 MOS	0.0 MOS	0.0 MOS		

Status Code Definitions

MOS = MONITOR OUT OF SERVICE NSA = NO SAMPLE AVAILABLE SVC = MONITOR IN SERVICE

The average opacity period average for the day was 0.4 % for 90 periods of valid data.

The Fan was in operation for 108 periods

The maximum opacity period average for the day was 0.4 %

There were 18 periods of invalid data

APPENDIX B
AUDIT FILTER CERTIFICATION SHEETS

Monitoring | Solutions

Leaders in Environmental Monitoring Systems & Services

4440 S. High School Rd., Suite D, Indianapolis, Indiana 46241 Tel: 317.856.9400

REPORT OF CERTIFICATION OF NEUTRAL DENSITY AUDIT FILTERS

Date of Filter Certification: **September 30, 2018**
Date of Filter Expiration: **March 30, 2019** **Filter Set - D**

Audit Device / Filter Slot Angle of Incidence **10** Degrees
Path-Length Correction **1.000** (Straight Stack)

Table 1: Individual Filter Certification Data

Serial Number	Opacity Value (%)	Transmittance (%)	Previous Opacity (%)	Change in Opacity (%)
VT59	8.4	91.6	8.4	0.0
VW72	18.2	81.8	18.2	0.0
ZB12	27.2	72.8	27.1	0.1
YG45	35.9	64.1	35.9	0.0
ZC32	43.9	56.1	43.8	0.1
YF63	59.8	40.2	59.7	0.1
VB86	86.3	13.7	86.2	0.1

J F Liphardt Jr

Laboratory-Based Transmissometer
Operator

See second page for Instrument Information and Details of Certification

Monitoring | Solutions
Leaders in Environmental Monitoring Systems & Services
4440 S. High School Rd., Suite D, Indianapolis, Indiana 46241 Tel: 317.856.9400

REPORT OF CERTIFICATION OF NEUTRAL DENSITY AUDIT FILTERS

- **Calibration of Laboratory-Based Transmissometer**

Instrument:
Durag Model 290
Transceiver S/N 414847, Reflector S/N 412508, Remote S/N 414861
Reference Material:
Primary Filters calibrated as specified in section 7.1.(2)(i) of Pt. 60, App. B, spec.1 of a nominal luminous transmittance of 50, 70, and 90 percent.

- **Description of Certification** (Pt. 60, App. B, Spec. 1, 7.2(i)(ii)(iii))

Conduct the secondary attenuator calibration using a laboratory-based transmissometer calibrated as follows:
Use at least three primary filters of nominal luminous transmittance 50, 70, and 90 percent, calibrated as specified in section 7.1(2)(i),to calibrate the laboratory-based transmissometer. Determine and record the slope of the calibration line using linear regression through zero opacity. The slope of the calibration line must be between 0.99 and 1.01 and the laboratory-based transmissometer reading for each primary filter must not deviate by more than +/- 2 percent from the linear regression line.

Immediately following the laboratory-based transmissometer calibration, insert the secondary attenuators and determine and record the percent effective opacity value per secondary attenuator from the calibration curve (linear regression line).

Recalibrate the secondary attenuators semi-annually if they are used for the required calibration error test.

ZERO ALIGNMENT CHECK

FOR

Primary Energy

East Chicago

Unit(s): Stack 201

MONITORING SOLUTIONS, INC.
MODEL: DURAG D-R 290 COMS

2018

Testing Completed On: 11/16/2018

PREPARED BY:

Monitoring | Solutions

Leaders in Environmental Monitoring Systems & Services

Monitoring Solutions, Inc. was contracted to conduct a Zero Alignment Check on a Durag Model D-R 290 opacity system. Testing was performed as per 40CFR60 Appendix F - Procedure 3.

Client:	Primary Energy	**Stack Correction Factor (SCF):**	1.000
City, State:	East Chicago		
Unit(s):	Stack 201		
Auditor:	Dan	**Durag Flange to Flange distance:**	226.125
Test Date:	11/16/2018		

Test results are as follows:

Unit ID :	Stack
Transceiver S/N :	1248342
Reflector S/N :	1248145
Remote S/N :	1248283
Clear Path Reading % :	0.1
Window Check Value % :	0.2
Zero Alignment Error % :	0.1
	PASS

* Zero Alignment Error must be ≤ 2% to pass

Reviewed by: *John Pollock*

Date: 1/23/2019

Revision: May 2015

Zero Alignment Error Check Procedure

The Zero Alignment Error Check is performed one time each year. This check utilizes the setup section of Durag's Clear Path procedure and verifies the “measuring” zero point of the unit in a known clear path setup. The transceiver and reflector are removed from their installation and set up on stands in a clean, dust free environment. The stands are set at the same distance as the installation location, referred to as the "Durag flange to flange distance". The optics on the unit are cleaned and the alignment is verified / adjusted as required. Without performing any electrical and/or mechanical adjustments to the transceiver, the measuring zero is compared to the simulated zero - or - Window Check. The difference between the measuring zero and the simulated zero, must NOT exceed 2% opacity.

Perform the following to document the "Zero Alignment Error":

a) Remove the Transceiver & Reflector from its current installation and setup on stands at the exact distance as their original location.

b) Connect and power up the remote (AW) unit and allow the system to complete a calibration check.

c) Check that the transceiver and reflector are properly aligned using the sighting window on the side of the transceiver. Adjust alignment as

d) Clean the transceiver's window & zero mirror; and the reflector. Perform a manual calibration to verify the internal compensation is at zero.

e) After unit has stabilized, record the Durag's response to the clear path zero in % opacity without any adjustment.

f) Activate the simulated zero (Window Check) and record the reading in % opacity without any adjustment.

g) The response difference between these two readings are recorded as the “zero alignment error”. The maximum allowable zero alignment error is 2%.

h) If the zero alignment error is 2% or less, then adjust the simulated zero (window check) to read the same value in % opacity as the clear path zero value. Continue to step k).

i) If the zero alignment error is greater than 2%, then perform the Durag Clear Path setup procedure.

j) After completion of the the Durag Clear Path procedure, document the final values in the second results box.

k) Power down the system and return the components to their original location and power up the system.

l) Verify alignment is correct and perform a manual Daily Calibration check and verify it passes.

ATTACHMENT 2

First Quarter 2019 Deviation and Compliance Monitoring Report

Cokenergy LLC
3210 Watling Street MC 2-991
East Chicago, IN 46312

April 29, 2019

Via UPS

Indiana Department of Environmental Management
Compliance and Enforcement Branch
Office of Air Quality
100 N. Senate Avenue
Mail Code 61-50, IGCN 1003
Indianapolis, IN 46204 - 2251

RE: Cokenergy, LLC Quarterly Report – First Quarter 2019
Part 70 Permit No. T089-36965-00383

To Whom It May Concern:

In accordance with sections C.18 and D.1.14 of the subject permit, 326 IAC 3-5-5 and 326 IAC 3-5-7, we have enclosed the first quarter 2019 reports for the Cokenergy, LLC facility. This report includes:

- Part 70 Quarterly Report – Certification
- Part 70 Quarterly Deviation and Compliance Report
- CEMS Excess Emissions Report
- CEMS Downtime Report
- COMS First Quarter 2019 Opacity Monitor Audit
- CEMS First Quarter 2019 Cylinder Gas Audit

If you have any questions concerning this data, please call Luke Ford at (219) 397-4626.

Sincerely,

Keith C. Kaufman
General Manager
Cokenergy LLC

Enclosure

cc: Luke Ford (scan via email)
Cliff Yukawa IDEM (scan via email)

File: X:\\ 615.4

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
OFFICE OF AIR MANAGEMENT
COMPLIANCE AND ENFORCEMENT SECTION
PART 70 OPERATING PERMIT
CERTIFICATION

Source Name: Cokenergy LLC

Source Address: 3210 Watling Street, MC 2-991, East Chicago, Indiana 46312-1610

Part 70 Permit No. : T089-36965-00383

This certification shall be included when submitting monitoring, testing reports/results or other documents as required by this permit.

Please check what document is being certified:

☐ Annual Compliance Certification Letter

☒ Test Result (specify) 1st Quarter 2019 COMS Performance Audit and Cylinder Gas Audit

☒ Report (specify) 1st Quarter 2019 Deviation and Compliance Monitoring Report

☐ Notification (specify) ______

☐ Affidavit (specify) ______

☐ Other (specify) ______

I certify that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete.

Signature: [signature]

Printed Name: Keith C. Kaufman

Title/Position: General Manager, Cokenergy, LLC

Phone: (219) 354-5009

Date: April 29, 2019

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
OFFICE OF AIR QUALITY
COMPLIANCE AND ENFORCEMENT BRANCH
PART 70 OPERATING PERMIT
QUARTERLY DEVIATION AND COMPLIANCE MONITORING REPORT

Source Name: Cokenergy LLC
Source Address: 3210 Watling Street, MC 2-991, East Chicago, Indiana 46312-1610
Part 70 Permit No. : T089-36965-00383

Months: January to March **Year:** 2019

This report shall be submitted quarterly based on a calendar year. Any deviation from the requirements, the date(s) of each deviation, the probable cause of the deviation, and the response steps taken must be reported. Deviations that are required to be reported by an applicable requirement shall be reported according to the schedule stated in the applicable requirement and do not need to be included in this report. Additional pages may be attached if necessary. If no deviations occurred, please specify in the box marked "No deviations occurred this reporting period".

☒ NO DEVIATIONS OCCURRED THIS REPORTING PERIOD

☐ THE FOLLOWING DEVIATIONS OCCURRED THIS REPORTING PERIOD

Permit Requirement: (specify permit condition #)	
Date of Deviation:	**Duration of Deviation:**
Number of Deviations:	
Probable Cause of Deviation:	
Response Steps Taken:	

Permit Requirement: (specify permit condition #)	
Date of Deviation:	**Duration of Deviation:**
Number of Deviations:	
Probable Cause of Deviation:	
Response Steps Taken:	

Permit Requirement: (specify permit condition #)	
Date of Deviation:	**Duration of Deviation:**
Number of Deviations:	
Probable Cause of Deviation:	
Response Steps Taken:	

Permit Requirement: (specify permit condition #)	
Date of Deviation:	**Duration of Deviation:**
Number of Deviations:	
Probable Cause of Deviation:	
Response Steps Taken:	

Permit Requirement: (specify permit condition #)	
Date of Deviation:	**Duration of Deviation:**
Number of Deviations:	
Probable Cause of Deviation:	
Response Steps Taken:	

Form Completed by: Keith C. Kaufman

Title / Position: General Manager, Cokenergy, LLC

Date: April 29, 2019

Phone: (219) 354-5005

Excess Emissions and Downtime Report

COKENERGY, LLC, East Chicago, IN
Plant ID: 089-00383
Emissions Unit ID: Stack 201
Emissions Unit: Heat Recovery Coke Carbonization Waste Heat Stack

PLANT OPERATIONS DOWNTIME SUMMARY

Reporting Period: 1st Quarter of 2019

Commencement of Emission Unit Downtime	Completion of Emission Unit Downtime	Emission Unit Downtime Duration (hours)	Reasons for Emission Unit Downtime
None			
Total Emission Unit Downtime for the quarter =		0	hours

COKENERGY, LLC, East Chicago, IN
Plant ID: 089-00383
Emissions Unit ID: Stack 201
Emissions Unit: Heat Recovery Coke Carbonization Waste Heat Stack

EXCESS EMISSIONS SUMMARY

Reporting Period: 1st Quarter of 2019

SO_2 Exceedances

Emission Standard: 1,656 lb/hr on a 24-hr average basis
(Note that this limit is for the combined emissions from Cokenergy Stack 201 and 16 IHCC Vent Stacks)

Date/Time of Commencement	Date/Time of Completion	Magnitude of Emissions (lb/hr)			Reasons for Excess Emissions	Corrective Actions Taken
		Main Stack Avg	Vent Stack Avg	Plant Avg		
None						

COKENERGY, LLC, East Chicago, IN
Plant ID: 089-00383
Emissions Unit ID: Stack 201
Emissions Unit: Heat Recovery Coke Carbonization Waste Heat Stack

EXCESS EMISSIONS SUMMARY

Reporting Period: 1st Quarter of 2019

Opacity Exceedances

Emission Standard: 20% opacity

Date/Time of Commencement	Date/Time of Completion	Magnitude of Emissions	Reasons for Excess Emissions	Corrective Actions Taken
		None		

COKENERGY, LLC, East Chicago, IN
Plant ID: 089-00383
Emissions Unit ID: Stack 201
Emissions Unit: Heat Recovery Coke Carbonization Waste Heat Stack

CONTINUOUS MONITORING SYSTEM DOWNTIME SUMMARY

Reporting Period: 1st Quarter of 2019

Opacity Monitor Downtime

Date/Time of Commencement	Duration of Downtime (minutes)	Reasons for Instrument Downtime	System Repairs and Adjustments
3/25/19 11:00	60	Quarterly PMs and Opacity Performance Audit	Routine preventative maintenance and quarterly audits
Total Downtime	60 minutes		

Note: Daily zero and span checks of the instrument have been excluded from the downtime summary per 326 IAC 3-5-7.

COKENERGY, LLC, East Chicago, IN
Plant ID: 089-00383
Emissions Unit ID: Stack 201
Emissions Unit: Heat Recovery Coke Carbonization Waste Heat Stack

CONTINUOUS MONITORING SYSTEM DOWNTIME SUMMARY

Reporting Period: 1st Quarter of 2019

SO_2 CEMS Downtime

Date/Time of Commencement	Duration of Downtime (hours)	Reasons for Instrument Downtime	System Repairs and Adjustments
2/24/19 7:00	26	O2 monitor calibration failure, per 40 CFR 60 Appendix F, previous 24 hours of data was also invalidated.	Recalibration of instrument
2/26/19 13:00	1	O2 monitor maintenance	Replaced O2 cell and recalibrated
3/25/19 10:00	3	Complete quarterly PMs and CGA on the CEMS	Routine quarterly preventative maintenance
Total Downtime	30 hours		

Note: Daily zero and span checks of the instrument have been excluded from the downtime summary per 326 IAC 3-5-7.

COKENERGY, LLC, East Chicago, IN
Plant ID: 089-00383
Emissions Unit ID: Stack 201
Emissions Unit: Heat Recovery Coke Carbonization Waste Heat Stack

CONTINUOUS MONITORING SYSTEM DOWNTIME SUMMARY

Reporting Period: 1st Quarter of 2019

Flow Monitor Downtime

Date/Time of Commencement	Duration of Downtime (hours)	Reasons for Instrument Downtime	System Repairs and Adjustments
		None	
Total Downtime	0 hours		

Note: Daily zero and span checks of the instrument have been excluded from the downtime summary per 326 IAC 3-5-7.

CYLINDER GAS AUDIT

FOR

Primary Energy

E. Chicago, IN

Unit: Stack 201

MONITORING SOLUTIONS, INC.
FULL EXTRACTIVE

First (1st) Quarter Results
2019

CGA Completed On: 3/25/2019

PREPARED BY:

Monitoring | Solutions
Leaders in Environmental Monitoring Systems & Services

TABLE OF CONTENTS

LIST OF TABLES

I. Introduction

Monitoring Solutions, Inc. was contracted to conduct a Cylinder Gas Audit on a Continuous Emission Monitoring System (CEMS). This audit was performed:

Client: Primary Energy
City, State: E. Chicago, IN
Unit: Stack 201
Auditor: Dan Bowles
Audit Date: 3/25/2019

The audit of the Continuous Emission Monitoring System was conducted for the following gases:

Gas #1 : SO2
Gas #2 : O2 Dry & O2 Wet

Our assessment of this quarter's CGA results indicates that all of the analyzers evaluated during this test program meet the accuracy requirements as outlined in 40 CFR 60, Appendix F.
NOTE: Table 1-1 summarizes the results for the cylinder gas audit.

Reviewed by: John Pollock

Date: 04/03/2019

Revision: June 2016

Summary of Cylinder Gas Audit Results

Parameter	Low Gas Error	Mid Gas Error
SO2	0.02	0.29
O2 Dry	2.00	2.71
O2 Wet	4.00	0.70
	Pass	Pass

Table 1-1

40 CFR 60, Appendix F Performance Test requirements: <15%

II. CYLINDER GAS AUDIT PROCEDURES

Each Continuous Emission Monitor (CEM) must be audited three out of four calendar quarters of each year. As part of the Quality Control (QC) and Quality Assurance (QA) procedures, the quality of data produced is evaluated by response accuracy compared to known standards,

The Cylinder Gas Audit (CGA) for this quarter was conducted in accordance with the QA/QC procedure outlined in 40 CFR 60, Appendix F.

All applicable audit gases are connected to the sampling system. Each gas is introduced into the sampling and analysis system. The gases flow through as much of the sampling path as possible.

The gases are actuated on and off by utilizing a computer and/or PLC controlled solenoids at designated time intervals.

a) Challenge each monitor (both pollutant and diluent, if applicable) with cylinder gases of known concentrations at two measurement points listed in Table 1-2.

b) Use a separate cylinder gas for measurement points 1 and 2. Challenge the CEMS three times at each measurement point and record the responses.

c) Use cylinder gases that have been certified by comparison to National Institute of Standards and Technology (NIST) gaseous standard reference material (SRM) or NIST/EPA approved gas manufacturer's certified reference material (CRM) following ''Traceability Protocol for Establishing True Concentrations of Gases Used for Calibration and Audits of Continuous Source Emission Monitors. (Protocol Number 1).''

<u>**NOTE:**</u> In rare cases, some operators may have pollutant cylinder gases that are not "Protocol 1". Pollutant cylinder gases in high concentrations may not be certifiable to the "Protocol 1 Standard" and are only available as a "Certified Standard" (e.g. Sulfur Dioxide [SO_2] in a concentration of 3.0% - or - 30,000 ppm).

Gas	*Measurement point #1*	*Measurement point #2*
Pollutants -	20-30% of span value	50-60% of span value
Diluent - O_2	4-6% by volume	8-12% by volume
Diluent - CO_2	5-8% by volume	10-14% by volume

Table 1-2

<u>**NOTE:**</u> Some operators may have cylinder gas values that fall outside of these parameters. This may be a result of previous agreements with their state or local EPA authority.

d) Determine the Relative Accuracy of each measurement point using the formula below. The RA error must not exceed 15%.

$$RA = \left|\left(\frac{\bar{d}}{AC}\right)100\right| \qquad \leq 15 \text{ percent}$$

Where:
RA = Relative Accuracy
$\bar{d}$ = Average of the three responses (Arithmetic Mean)
AC = The certified concentration of the cylinder gas.

III. Cylinder Gas Audit Data Sheets

CYLINDER GAS AUDIT (CGA) ERROR DETERMINATION

CLIENT: Primary Energy
PLANT / SITE: E. Chicago, IN
UNIT ID: Stack 201

MONITOR TESTED: SO_2
RANGE : 0 - 700 PPM

CONDUCTED BY : Dan Bowles
ATTENDEE : N/A
AUDIT DATE: 3/25/2019

ANALYZER SERIAL NUMBER: 1152150034

	Run	Time	Reference value	Monitor value	Difference	Error %
Low-level	1	12:29	176.50	176.90	0.40	0.23 %
	2	12:47	176.50	176.10	-0.40	-0.23 %
	3	13:05	176.50	176.40	-0.10	-0.06 %
Mid-level	1	12:23	385.00	385.50	0.50	0.13 %
	2	12:41	385.00	385.80	0.80	0.21 %
	3	12:59	385.00	387.10	2.10	0.55 %

Low-level

Arithmetic Mean: 176.47

CGA Error: 0.02 %

Tank S/N CC14789
Tank Expiration Date 7/25/2025

Mid-Level

Arithmetic Mean: 386.13

CGA Error: 0.29 %

Tank S/N CC125121
Tank Expiration Date 8/22/2026

CGA Report

03/25/2019 - 03/25/2019

Date	Parameter	Run#	Timestamp	Type	Expected	Measured	Low Diff	------	Mid Diff	------
03/25/2019										
	SO2, PPM	1	12:23:56	QTR_MID	385.0	385.5			0.5	
	SO2, PPM	1	12:29:56	QTR_LOW	176.5	176.9	0.4			
	SO2, PPM	2	12:41:57	QTR_MID	385.0	385.8			0.8	
	SO2, PPM	2	12:47:57	QTR_LOW	176.5	176.1	0.4			
	SO2, PPM	3	12:59:56	QTR_MID	385.0	387.1			2.1	
	SO2, PPM	3	13:05:56	QTR_LOW	176.5	176.4	0.1			

Arithmetic Mean of Quarterly Low : 176.5
Linearity Error of Quarterly Low : 0.0
Calibration Tolerance: 15.0

Arithmetic Mean of Quarterly Mid : 386.1
Linearity Error of Quarterly Mid : 0.3
Calibration Tolerance: 15.0

Calibration Result : Pass

CEMS Type : Full Extractive
Manufacturer: Thermo
Model Number : 43i-HL
Serial Number: 1152150034
Monitor Certification Date:

Tested By : ____________________

Date: ____________________

CYLINDER GAS AUDIT (CGA) ERROR DETERMINATION

CLIENT: Primary Energy
PLANT / SITE: E. Chicago, IN
UNIT ID: Stack 201

MONITOR TESTED: O2 Dry
RANGE : 0 - 25 %

CONDUCTED BY : Dan Bowles
ATTENDEE : N/A
AUDIT DATE: 3/25/2019

ANALYZER SERIAL NUMBER: 11400

	Run	Time	Reference value	Monitor value	Difference	Error %
Low-level	1	12:29	5.00	4.90	-0.10	-2.00 %
	2	12:47	5.00	4.90	-0.10	-2.00 %
	3	13:05	5.00	4.90	-0.10	-2.00 %
Mid-level	1	12:35	9.97	9.70	-0.27	-2.71 %
	2	12:53	9.97	9.70	-0.27	-2.71 %
	3	13:11	9.97	9.70	-0.27	-2.71 %

Low-level

Arithmetic Mean: 4.90

CGA Error: 2.00 %

Tank S/N CC14789
Tank Expiration Date 7/25/2025

Mid-Level

Arithmetic Mean: 9.70

CGA Error: 2.71 %

Tank S/N CC400438
Tank Expiration Date 8/16/2025

Primary Energy Coke

East Chicago, IN

CGA Report

03/25/2019 - 03/25/2019

Created on : Mar 25, 2019 13:12:00

STACK 201

Date	Parameter	Run#	Timestamp	Type	Expected	Measured	Low Diff	-------	Mid Diff	-------
03/25/2019										
	O2 DRY, %	1	12:29:56	QTR_LOW	5.0	4.9	0.1			
	O2 DRY, %	1	12:35:57	QTR_MID	10.0	9.7			0.3	
	O2 DRY, %	2	12:47:57	QTR_LOW	5.0	4.9	0.1			
	O2 DRY, %	2	12:53:57	QTR_MID	10.0	9.7			0.3	
	O2 DRY, %	3	13:05:56	QTR_LOW	5.0	4.9	0.1			
	O2 DRY, %	3	13:11:56	QTR_MID	10.0	9.7			0.3	

Arithmetic Mean of Quarterly Low : 4.9
Linearity Error of Quarterly Low : 2.2
Calibration Tolerance: 15.0

Arithmetic Mean of Quarterly Mid : 9.7
Linearity Error of Quarterly Mid : 2.7
Calibration Tolerance: 15.0

Calibration Result : Pass

CEMS Type : Full Extractive
Manufacturer: Brand Gaus
Model Number : 4705
Serial Number: 11400
Monitor Certification Date:

Tested By : ______________________

Date: ______________________

CYLINDER GAS AUDIT (CGA) ERROR DETERMINATION

CLIENT: Primary Energy
PLANT / SITE: E. Chicago, IN
UNIT ID: Stack 201

MONITOR TESTED: O2 Wet
RANGE : 0 - 25 %

CONDUCTED BY : Dan Bowles
ATTENDEE : N/A
AUDIT DATE: 3/25/2019

ANALYZER SERIAL NUMBER: 11401

	Run	Time	Reference value	Monitor value	Difference	Error %
Low-level	1	12:29	5.00	4.80	-0.20	-4.00 %
	2	12:47	5.00	4.80	-0.20	-4.00 %
	3	13:05	5.00	4.80	-0.20	-4.00 %
Mid-level	1	12:35	9.97	9.90	-0.07	-0.70 %
	2	12:53	9.97	9.90	-0.07	-0.70 %
	3	13:11	9.97	9.90	-0.07	-0.70 %

Low-level

Arithmetic Mean: 4.80

CGA Error: **4.00 %**

Tank S/N CC14789

Tank Expiration Date 7/25/2025

Mid-Level

Arithmetic Mean: 9.90

CGA Error: **0.70 %**

Tank S/N CC400438

Tank Expiration Date 8/16/2025

CGA Report

03/25/2019 - 03/25/2019

Date	Parameter	Run#	Timestamp	Type	Expected	Measured	Low Diff	-------	Mid Diff	-------
03/25/2019										
	O2 WET, %	1	12:29:56	QTR_LOW	5.0	4.8	0.2			
	O2 WET, %	1	12:35:57	QTR_MID	10.0	9.9			0.1	
	O2 WET, %	2	12:47:57	QTR_LOW	5.0	4.8	0.2			
	O2 WET, %	2	12:53:57	QTR_MID	10.0	9.9			0.1	
	O2 WET, %	3	13:05:56	QTR_LOW	5.0	4.8	0.2			
	O2 WET, %	3	13:11:56	QTR_MID	10.0	9.9			0.1	

Arithmetic Mean of Quarterly Low : 4.8
Linearity Error of Quarterly Low : 4.2
Calibration Tolerance: 15.0

Arithmetic Mean of Quarterly Mid : 9.9
Linearity Error of Quarterly Mid : 0.7
Calibration Tolerance: 15.0

Calibration Result : Pass

CEMS Type : Full Extractive
Manufacturer: Brand Gaus
Model Number : 4705
Serial Number: 11401
Monitor Certification Date:

Tested By : ______________________________

Date: ___________________________________

IV. Cylinder Gas Certification Sheets

Airgas.
an Air Liquide company

In Service 9/29/17

Airgas USA, LLC
12722 S. Wentworth Ave.
Chicago, IL 60628
Airgas.com

CERTIFICATE OF ANALYSIS
Grade of Product: EPA Protocol

Part Number:	E04NI84E15A0007	Reference Number:	54-124629354-1
Cylinder Number:	CC14789	Cylinder Volume:	150.4 CF
Laboratory:	124 - Chicago - IL	Cylinder Pressure:	2015 PSIG
PGVP Number:	B12017	Valve Outlet:	660
Gas Code:	CO2,O2,SO2,BALN	Certification Date:	Jul 25, 2017

Expiration Date: Jul 25, 2025

Certification performed in accordance with "EPA Traceability Protocol for Assay and Certification of Gaseous Calibration Standards (May 2012)" document EPA 600/R-12/531, using the assay procedures listed. Analytical Methodology does not require correction for analytical interference. This cylinder has a total analytical uncertainty as stated below with a confidence level of 95%. There are no significant impurities which affect the use of this calibration mixture. All concentrations are on a volume/volume basis unless otherwise noted.

Do Not Use This Cylinder below 100 psig, i.e. 0.7 megapascals.

ANALYTICAL RESULTS

Component	Requested Concentration	Actual Concentration	Protocol Method	Total Relative Uncertainty	Assay Dates
[redacted]	175.0 PPM	[redacted]	G1	+/- 1.0% NIST Traceable	07/17/2017, 07/25/2017
	5.000 %		G1	+/- 1.0% NIST Traceable	07/18/2017
CARBON DIOXIDE	10.00 %	10.00 %	G1	+/- 0.9% NIST Traceable	07/17/2017
NITROGEN	Balance				

CALIBRATION STANDARDS

Type	Lot ID	Cylinder No	Concentration	Uncertainty	Expiration Date
NTRM	16060140	CC437515	515.2 PPM SULFUR DIOXIDE/NITROGEN	+/- 0.8%	Nov 16, 2021
NTRM	11060719	CC338460	4.861 % OXYGEN/NITROGEN	+/- 0.4%	Dec 13, 2022
NTRM	13060635	CC413759	13.359 % CARBON DIOXIDE/NITROGEN	+/- 0.6%	May 09, 2019

ANALYTICAL EQUIPMENT

Instrument/Make/Model	Analytical Principle	Last Multipoint Calibration
Nicolet 6700 AHR0801332	FTIR	Jun 21, 2017
O2-1 HORIBA MPA-510 3VUYL9NR	Paramagnetic	Jul 17, 2017
Nicolet 6700 AHR0801332	FTIR	Jul 21, 2017

Triad Data Available Upon Request

Approved for Release

In Service 9/29/17

Airgas.
an Air Liquide company

Airgas Specialty Gases
Airgas USA, LLC
12722 S. Wentworth Ave.
Chicago, IL 60628
Airgas.com

CERTIFICATE OF ANALYSIS

Grade of Product: EPA Protocol

Part Number:	E02NI90E15A0228	Reference Number:	54-400967311-1
Cylinder Number:	CC400438	Cylinder Volume:	145.2 CF
Laboratory:	124 - Chicago (SAP) - IL	Cylinder Pressure:	2015 PSIG
PGVP Number:	B12017	Valve Outlet:	590
Gas Code:	O2,BALN	Certification Date:	Aug 16, 2017

Expiration Date: Aug 16, 2025

Certification performed in accordance with "EPA Traceability Protocol for Assay and Certification of Gaseous Calibration Standards (May 2012)" document EPA 600/R-12/531, using the assay procedures listed. Analytical Methodology does not require correction for analytical interference. This cylinder has a total analytical uncertainty as stated below with a confidence level of 95%. There are no significant impurities which affect the use of this calibration mixture. All concentrations are on a volume/volume basis unless otherwise noted.

Do Not Use This Cylinder below 100 psig, i.e. 0.7 megapascals.

ANALYTICAL RESULTS

Component	Requested Concentration	Actual Concentration	Protocol Method	Total Relative Uncertainty	Assay Dates
[redacted]	10.00 %	[redacted]	G1	+/- 1% NIST Traceable	08/16/2017
NITROGEN	Balance				

CALIBRATION STANDARDS

Type	Lot ID	Cylinder No	Concentration	Uncertainty	Expiration Date
NTRM	06120102	CC195613	9.898 % OXYGEN/NITROGEN	+/- 0.7%	Jul 26, 2018

ANALYTICAL EQUIPMENT

Instrument/Make/Model	Analytical Principle	Last Multipoint Calibration
O2-1 HORIBA MPA-510 3VUYL9NR	Paramagnetic	Jul 17, 2017

Triad Data Available Upon Request

Approved for Release

Airgas
an Air Liquide company

Airgas Specialty Gases
Airgas USA, LLC
12722 S. Wentworth Ave.
Chicago, IL 60628
Airgas.com

CERTIFICATE OF ANALYSIS

Grade of Product: EPA Protocol

Part Number:	E03NI89E15A0052	Reference Number:	54-124629358-1
Cylinder Number:	CC89122	Cylinder Volume:	149.9 CF
Laboratory:	124 - Chicago (SAP) - IL	Cylinder Pressure:	2015 PSIG
PGVP Number:	B12017	Valve Outlet:	660
Gas Code:	CO2,SO2,BALN	Certification Date:	Jul 17, 2017

Expiration Date: Jul 17, 2025

Certification performed in accordance with "EPA Traceability Protocol for Assay and Certification of Gaseous Calibration Standards (May 2012)" document EPA 600/R-12/531, using the assay procedures listed. Analytical Methodology does not require correction for analytical interference. This cylinder has a total analytical uncertainty as stated below with a confidence level of 95%. There are no significant impurities which affect the use of this calibration mixture. All concentrations are on a volume/volume basis unless otherwise noted.

Do Not Use This Cylinder below 100 psig, i.e. 0.7 megapascals.

ANALYTICAL RESULTS

Component	Requested Concentration	Actual Concentration	Protocol Method	Total Relative Uncertainty	Assay Dates
SULFUR DIOXIDE	385.0 PPM	387.3 PPM	G1	+/- 0.8% NIST Traceable	07/17/2017
CARBON DIOXIDE	10.00 %	9.994 %	G1	+/- 1.0% NIST Traceable	07/17/2017
NITROGEN	Balance			-	

CALIBRATION STANDARDS

Type	Lot ID	Cylinder No	Concentration	Uncertainty	Expiration Date
NTRM	16060140	CC437515	515.2 PPM SULFUR DIOXIDE/NITROGEN	+/- 0.8%	Nov 16, 2021
NTRM	13060635	CC413759	13.359 % CARBON DIOXIDE/NITROGEN	+/- 0.6%	May 09, 2019

ANALYTICAL EQUIPMENT

Instrument/Make/Model	Analytical Principle	Last Multipoint Calibration
Nicolet 6700 AHR0801332	FTIR	Jun 21, 2017
Nicolet 6700 AHR0801332	FTIR	Jun 21, 2017

Triad Data Available Upon Request

Signature on file

Approved for Release

Airgas.
an Air Liquide company

Airgas Specialty Gases
Airgas USA, LLC
12722 S. Wentworth Ave.
Chicago, IL 60628
Airgas.com

In Service
2/8/19

CERTIFICATE OF ANALYSIS
Grade of Product: EPA Protocol

Part Number:	E03NI89E15A0052	Reference Number:	54-401283400-1
Cylinder Number:	CC125121	Cylinder Volume:	149.9 CF
Laboratory:	124 - Chicago (SAP) - IL	Cylinder Pressure:	2015 PSIG
PGVP Number:	B12018	Valve Outlet:	660
Gas Code:	CO2,SO2,BALN	Certification Date:	Aug 22, 2018

Expiration Date: Aug 22, 2026

Certification performed in accordance with "EPA Traceability Protocol for Assay and Certification of Gaseous Calibration Standards (May 2012)" document EPA 600/R-12/531, using the assay procedures listed. Analytical Methodology does not require correction for analytical interference. This cylinder has a total analytical uncertainty as stated below with a confidence level of 95%. There are no significant impurities which affect the use of this calibration mixture. All concentrations are on a volume/volume basis unless otherwise noted.

Do Not Use This Cylinder below 100 psig, i.e. 0.7 megapascals

ANALYTICAL RESULTS

Component	Requested Concentration	Actual Concentration	Protocol Method	Total Relative Uncertainty	Assay Dates
SULFUR DIOXIDE	385.0 PPM	385.0 PPM	G1	+/- 0.9% NIST Traceable	08/16/2018, 08/22/2018
CARBON DIOXIDE	10.00 %	10.04 %	G1	+/- 0.8% NIST Traceable	08/16/2018
NITROGEN	Balance				

CALIBRATION STANDARDS

Type	Lot ID	Cylinder No	Concentration	Uncertainty	Expiration Date
NTRM	16060140	CC437515	515.2 PPM SULFUR DIOXIDE/NITROGEN	+/- 0.8%	Nov 16, 2021
NTRM	13060635	CC413759	13.359 % CARBON DIOXIDE/NITROGEN	+/- 0.6%	May 09, 2019

ANALYTICAL EQUIPMENT

Instrument/Make/Model	Analytical Principle	Last Multipoint Calibration
Nicolet 6700 AHR0801332	FTIR	Jul 23, 2018
Nicolet 6700 AHR0801332	FTIR	Jul 23, 2018

Triad Data Available Upon Request

Approved for Release

OPACITY PERFORMANCE AUDIT

FOR

Primary Energy

E. Chicago, IN

Unit: Stack 201

MONITORING SOLUTIONS, INC.
MODEL: DURAG D-R 290 COMS

First (1st) Quarter Results
2019

Audit Completed On: 3/25/2019

PREPARED BY:

Monitoring Solutions

Leaders in Environmental Monitoring Systems & Services

TABLE OF CONTENTS

I. Introduction

Monitoring Solutions, Inc. was contracted to conduct an opacity performance audit on a Durag Model D-R 290 opacity system.

Client: Primary Energy
City, State: E. Chicago, IN
Auditor: Dan Bowles
Audit Date: 3/25/2019

The performance testing consists of:

1. Zero and Span Check
2. Zero Compensation Check
3. Optical Alignment Check
4. Calibration Error Check
5. Annual Zero Alignment (When required)

All raw data, calculated data and final summary are presented. The results indicate compliance for all specifications. Testing was performed as per 40CFR60 Appendix F and 40CFR60 Appendix B, PS1 (Where Applicable).

Annual "Zero Alignment" check performed this quarter:

YES: ________ NO: X ERROR: N/A

Summary of Calibration Error Check

Filter :	Low	Mid	High
Percent of Error:	0.30	0.45	0.10
	PASS	PASS	PASS

Reviewed by: John Pollock

Date: 04/03/2019

Revision: March 2016

PERFORMANCE AUDIT PROCEDURES FOR THE MONITORING SOLUTIONS, INC. OPACITY MONITOR

II. Monitoring Solutions, Inc. Durag Model D-R 290

The instrument is manufactured by the Durag Corporation and distributed and serviced by Monitoring Solutions, Inc.

A. COMS Description

The Monitoring Solutions, Inc. D-R 290 opacity monitoring system consists of four major components: the Transmissometer, the terminal control box, the air-purging system and the remote control unit and data acquisition equipment. The Transmissometer component consists of an optical transmitter/receiver (transceiver) unit mounted on one side of a stack or duct and a retro reflector unit mounted on the opposite side. The transceiver unit contains the light source, the photodiode detector, and the associated electronics. The transceiver uses a single-lamp, single detector system to determine effluent opacity. A LED light source is modulated electronically at 2 KHz to eliminate any ambient light interference. The modulated beam is configured to alternately produce reference and measurement signals so that the effects of variations in the optical and electronic components of the COMS are minimized.

In a single display configuration, an AW unit is mounted in a blue housing next to the transceiver location. In a dual display configuration, an AZ unit is mounted in the blue housing next to the transceiver location and an AW is mounted in a remote location, typically, a control room. The AZ and the AW communicate via an RS 422 cable. The AZ unit provides an on stack readout and can be used as a diagnostic tool. In either configuration, only the AW provides the signals to the final recording device.

The air purging system serves a threefold purpose: 1) it provides an air window to keep exposed optical surfaces clean; 2) it protects the optical surfaces from condensation of stack gas moisture; and 3) it minimizes thermal conduction from the stack to the instrument. A standard installation has one air-purging system for each the transceiver and the retro reflector units.

The opacity monitor measures the amount of light transmitted through the effluent from the transceiver to the retro reflector and back again. The control unit uses the effluent transmittance to calculate the optical density of the effluent at the monitor location, or the "path" optical density. In order to provide stack exit opacity data, the path optical density must be corrected. The correction factor is expressed as the ratio of the stack exit inside diameter to the inside diameter of the stack at the Transmissometer location. This ratio is called the "stack correction factor" (SCF) by Monitoring Solutions, Inc. The following equations illustrate the relationship between this ratio, path optical density, and stack exit opacity.

Calculation of "Stack Correction Factor"

	L_x / L_t	=	stack correction factor
where:	L_x	=	stack exit inside diameter (in)
	L_t	=	the stack inside diameter (or the duct width) at the monitor location (in).
	OP_x	=	$1-(1-\frac{Opacity}{100})^{correction\ factor}$
	OP_x	=	stack exit opacity (%)

B. Performance Audit Procedures

1. Preliminary Data

a. Obtain the stack exit inside diameter (in feet) and the stack inside diameter at the monitor location (in feet). Record these values in Blanks 1 and 2 of the Monitoring Solutions, Inc. D-R 290 Performance Audit Data Sheet.

Note: Effluent handling system dimensions may be acquired from the following sources listed in descending order of reliability: 1) physical measurements, 2) construction drawings, 3) opacity monitor installation/certification documents, and 4) source personnel recollections.

b. Calculate the stack correction factor (SCF) by dividing the value in Blank 1 by the value in Blank 2. Record the result in Blank 3.

c. Record the source-cited Stack Correction Factor (SCF) in Blank 4.

Note: The stack correction factor (SCF) is preset by the manufacturer using information supplied by the source. The value recorded in Blank 4 should be the value source personnel agree should be set inside the monitor.

d. Obtain the reference zero and span calibration values. Record these values in Blank 5 and Blank 6, respectively.

Note: The reference zero and span calibration values may not be the same as the values recorded during instrument installation and/or certification. The zero and span values recorded in Blank 5 and Blank 6 should be the reference values recorded during the most recent clear-path calibration of the CEMS.

2. **Error Checks**

The following steps describe the error codes for the Monitoring Solutions, Inc. D-R 290 remote control unit. The audit can continue with the error codes shown below being present, provided the source has been informed of the fault conditions. All other error codes must be corrected prior to audit.

Error code 100 = Transceiver blower fault
Error code 200 = Transceiver filter plugged
Error code 300 = Reflector blower fault
Error code 400 = Reflector filter plugged

Note: If a fault is active, an error code will be displayed on the stack mounted display and on the remote display. An explanation of the error codes can be found in the manual.

3. **Instrument Range Check**

a. Check the COMS measurement range by pressing the MOD button (the LED on the button will light up) and using the PLUS button to cycle through the displays.

b. Record the instrument range in Blank 11.

4. **Reference Signal, Zero and Span Checks**

a. Initiate the calibration cycle by pressing the arrow and plus buttons simultaneously and holding for approximately 5 seconds.

Note: The opacity monitor will automatically cycle through the internal zero (zero point check), external zero (window check), span and stack taper ratio modes. Approximately 6 minutes for a complete cycle.

b. Record the milliamp value shown for the internal zero (zero point check) displayed on the control panel display in Blank 12.

Note: The internal zero checks the instrument reference signal (Zero Point Check). Since the instrument provides a full scale output of 4 to 20 milliamps, a value of 4 milliamps displayed on the control unit display represents a zero condition. After 1 ½ minutes in the internal zero mode, the monitor will automatically switch to the external zero mode (Window Check).

c. Record the milliamp value shown for the external zero (window check) displayed on the control panel in Blank 13. Also record the external zero value (in percent opacity) displayed on the opacity data recorder in Blank 14.
(Continued on next page)

Note: During the zero calibration check, the zero mirror is moved into the path of the measurement beam by a servomotor. The zero mechanism is designed to present the transceiver with a simulated clear-path condition. The daily zero check does not test the actual clear-path zero, nor does it provide a check of cross-stack parameters such as the optical alignment of the Transmissometer or drift in the reflectance of the retro reflector. The actual clear-path zero can only be checked during clear-stack or off-stack calibration of the CEMS. In addition to simulating the instrument clear-path zero, the zero mechanism allows the amount of dust on the transceiver optics (primary lens and zero mirror) to be quantified. After 1 ½ minutes in the external zero mode, the CEMS will automatically enter the span mode.

d. Record in Blank 15 the span value (in milliamps) displayed on the control panel display. Also record the span value (in percent opacity) displayed on the data recorder in Blank 16. Go to the Transmissometer location.

Note: During the span calibration check, a servomotor moves an internal span filter into the path of the measurement beam while the zero mirror is in place. The span mechanism is designed to provide an indication of the upscale accuracy of the CEMS relative to the simulated clear-path zero. Note: The opacity monitor display will output its stack correction factor (SCF) for 1 ½ minutes when the span portion of the calibration cycle is completed. The CEMS automatically returns to the measurement mode when the SCF portion of the calibration cycle is complete.

5. **Reflector Dust Accumulation Check.**

a. Record the effluent opacity prior to cleaning the retroreflector optics in Blank 17.

b. Open the reflector housing, inspect and clean the retroreflector optics, and close the housing.

c. Record the post-cleaning effluent opacity in Blank 18. Go to the transceiver location.

6. **Transceiver Dust Accumulation Check.**

a. Record the pre-cleaning effluent opacity in Blank 19.

b. Open the transceiver, clean the optics (primary window and zero mirror) and close the transceiver.

c. Record the post-cleaning effluent opacity in Blank 20.

7. **Alignment Check**

a. Determine the monitor alignment by looking through the alignment port of the side of the transceiver.

b. Observe whether the image is centered in the cross hairs and record this information (YES or NO) in Blank 21.

8. **Zero Compensation Check**

The Durag 290 provides internal compensation for window contamination. This compensation value can be determined by performing the Window Check. This compensation cannot be disabled for testing. Remove internal compensation as follows: Clean the transceiver window and the zero mirror lens. Verify the window check value is at zero so no compensation is applied to the quarterly audit. Enter the Filter Audit Mode and verify the starting Durag opacity value is zero percent. **NOTE:** This process must be completed prior to the Calibration Error Check.

9. **Zero Alignment Error Check**

The Zero Alignment Error Check is performed one time each year. This check utilizes Durag's Clear Path Procedure. This procedure verifies the "measuring" zero point of the unit in a known clear path setup. The Transceiver and reflector are removed from their installation and set up on stands in a clean, dust free environment. The stands are set at the same distance as the installation location. Without performing any adjustments, the measuring zero is compared to the simulated zero - or - Window Check. The difference between the measuring zero and the simulated zero, must NOT exceed 2% opacity.

Verify the Zero Compensation Check has been performed. Since the zero compensation function cannot be disabled for the zero alignment check, the optics must be cleaned and a manual calibration performed. This will set the internal compensation value to 0.0%. This MUST be accomplished prior to the Zero Alignment Check.

Perform the following to document the "Zero Alignment Error":

a) Remove the Transceiver & Reflector from its current installation and setup on stands at the exact distance as their original location.

b) Perform the Zero Compensation Check and perform a manual calibration.

c) Record the Durag's response to the clear path zero in % opacity without any adjustment.

d) Activate the simulated zero (Window Check) and record the reading in % opacity without any adjustment.
(continued on next page)

e) The response difference between these two readings are recorded as the "zero alignment error". The maximum allowable zero alignment error is 2%.

f) Adjust the simulated zero (window check) to read the same value in % opacity as the clear path zero.

10. Calibration Error Check

The calibration error check is performed using three neutral density filters. Performing the calibration error check on-stack using the filters determines the linearity of the instrument response relative to the current clear-path zero setting. This calibration error check does not determine the accuracy of the actual instrument clear-path zero or the status of any cross-stack parameters. A true calibration check is performed by moving the on-stack components to a location with minimal ambient opacity, making sure that the proper path length and alignments are attained, and then placing the calibration filters in the measurement path.

a. Put the monitor in Filter Audit mode.

b. Wait approximately three minutes or until a clear "zero" value has been recorded and displayed on the data recorder.

c. Record the audit filter serial numbers and opacity values in Blanks 22, 23, and 24.

d. Remove the filters from their protective covers, inspect and if necessary, clean them.

e. Insert the low range neutral density filter into the filter audit slot located in front of the heated lens.

f. Wait approximately three minutes or until a clear value has been recorded and displayed on the data recorder.

Note: The audit data should be taken from a data recording/reporting device that presents instantaneous opacity (or opacity data with the shortest available integration period).

g. Record the COMS response to the low range neutral density filter.

h. Remove the low range filter and insert the mid range neutral density filter.

i. Wait approximately three minutes and record the COMS response to the mid range neutral density filter.

j. Remove the mid range filter and insert the high range filter.

k. Wait approximately three minutes and record the COMS response to the high range neutral density filter.
(continued on next page)

l. Remove the high range filter.

m. * If applicable, wait approximately three minutes, and record the zero value.

n. Repeat steps (e) through (m) until a minimum of <u>three</u> opacity readings are obtained for each neutral density filter.

o. If six-minute integrated opacity data is required, repeat steps (e) through (m) once more, changing the waiting periods to 13 minutes.

p. Record the six-minute integrated data.

Note: In order to acquire valid six-minute averaged opacity data, each filter must remain in for at least two consecutive six-minute periods; the first period will be invalid because it was in progress when the filter was inserted. A waiting period of 13 minutes is recommended. You should have a "starting zero" reading and an "ending zero" reading.

q. When the calibration error check is complete, return the monitor to measuring mode. Close the transceiver head and the weather cover, and return to the COMS control unit.

11. Test Conclusion

a. Obtain a copy of the audit data from the data recorder.

b. Transcribe the calibration error response from the data recorder to Blanks 25 through 50 of the audit form and complete the audit data calculations.

C. Interpretation of Audit Results

This section is designed to help the auditor interpret the D-R 290 performance audit results.

Error codes / fault analysis

Error codes are typically associated with parameters that the monitor manufacturer feels are critical to COMS function, and to the collection of valid opacity data. The parameters associated with each of the error codes are found in the manufacturer's manual. With the exception of alarms that warn of elevated opacity levels (alarm or warning lamps), the error codes indicate that the COMS is not functioning properly. An error or failure indication will be represented by a "YES" in Blanks 7 - 10.

(continued on next page)

Stack Exit Correlation Error Check

The path length correction error in Blank 51 should be within +2%. This error exponentially affects the opacity readings, resulting in over - or - underestimation of the stack exit opacity. The most common error in computing the optical path length correction factor is the use of the flange-to-flange distance in place of the stack/duct inside diameter at the monitor location. This error will result in underestimation of the stack exit opacity and can be identified by comparing the monitor optical path length to the flange-to-flange distance; the flange-to-flange distance should be greater by approximately two to four feet

Control Panel Meter Error (Optional)

The accuracy of the control panel meter (AW) is important at sources using the meter during monitor adjustment and calibration. The accuracy of the control panel meter (Blank 52 and Blank 54) is determined by comparing the zero and span reference values to the panel meter output recorded during the COMS calibration check.

Note: Some installations utilize a different "Instrument Range Setting" than the normal 100% range. The panel meter span error must be corrected for the different range in order to provide an accurate error result. Use the following equation to calculate the span error corrected for "Instrument Range" (Blank 11):

Panel Meter span error in % opacity =

$$(((\text{Blank } 15 - 4) \div 16) \times \text{Blank } 11) - \text{Blank } 6$$

Zero and Span Checks

The D-R 290 internal zero or "zero point check" (Blank 12 should be set to indicate 0% opacity (equivalent to 3.7 - 4.3 mA). An external zero error or "window check" (Blank 53) greater than 4% opacity is usually due to excessive dust accumulation on the optical surfaces, electronic drift or an electronic/mechanical offset of the data recorder. Excessive dust on the optical surfaces sufficient to cause a significant zero error would be indicated by the difference in the internal and external zero values and/or window alarm. Instrument span error (Blank 55) may be caused by the same problem(s) that cause zero errors and may be identified in a similar fashion.

If the zero and span errors are due to a data recorder offset, both errors will be in the same direction and will be of the same magnitude

(continued on next page)

The external zero displayed on the control unit panel meter (AW) also indicates the level of dust accumulation on the zero retroreflector and transceiver measurement window. The difference between the internal and external zero responses should equal the amount of dust found on the transceiver optics (Blank 57). To convert the zero responses to a value that represents lens dusting in percent opacity, use the following equation.

Meter response in % opacity = 6.25 [(Blank 13) - (Blank 12)]

Optical Alignment Check

When the transceiver and retroreflector are misaligned, a portion of the measurement beam that should be returned to the measurement detector is misdirected, resulting in a positive bias in the data reported by the COMS. One of the most common causes of misalignment is vibration which may cause the on-stack components to shift slightly on the instrument mounting flanges. Another common cause of misalignment is thermal expansion and contraction of the structure on which the transmissometer is mounted. If the COMS is being audited while the unit is off-line (cold stack), the results of the alignment analysis may not be representative of the alignment of the instrument when the stack or duct is at normal operating temperature. When checking the alignment, the reflected light beam should be centered.

Zero Compensation Check

The Zero Compensation Check should be performed and documented as such in (Blank 21a).

Annual Zero Alignment Error Check

The Zero Alignment Error Check is performed once each year. It verifies that the enegy output from the simulated zero device (Window Check) is within 2% of the Clear Path reading. The values required for this check are documented in (Blank 21b). If the difference between the Clear Path Value and the Simulated Zero (Window Check) value differ by more than 2%, then the COMS unit is considered Out Of Control. If the difference is 2% or less, then the Window Check Value is adjusted to match the Clear Path value.

Optical Surface Dust Accumulation Check

The results of the dust accumulation check (Blank 58) should not exceed 4%. A dust accumulation value of more than 4% opacity indicates that the air flow of the purge system and/or the cleaning frequency of the optical surfaces are inadequate. When determining the optical surface dust accumulation, the auditor should note whether the effluent opacity is relatively stable (within +2% opacity) before and after cleaning the optical surfaces. If the effluent opacity is fluctuating by more that +2%, the dust accumulation analysis should be omitted.

(continued on next page)

Calibration Error

Calibration error results (Blanks 68, 69 and 70) in excess of +3% are indicative of a non-linear or miss calibrated instrument. However, the absolute calibration accuracy of the monitor can be determined only when the instrument clear-path zero value is known. If the zero and span data are out-of-specification, the calibration error data will often be biased in the direction of the zero and span errors. Even if the zero and span data indicate that the COMS is calibrated properly, the monitor may still be inaccurate due to error in the clear-path zero adjustment. The optimum calibration procedure involves using neutral density filters during clear-stack or off-stack COMS calibration. This procedure would establish both the absolute calibration accuracy and linearity of the COMS. If this procedure is impractical, and it is reasonable to assume that the clear-path zero is set correctly, the monitor's calibration can be set using either the neutral density filters or the internal zero and span values.

Appendix A
COMS Audit Data Forms for the Durag Model D-R 290

AUDIT DATA SHEET

MONITORING SOLUTIONS DURAG D-R 290 COMS

Company: Primary Energy

Unit ID: Stack 201

Auditor: Dan Bowles

Attendees: N/A

Transceiver serial number: 1248342

Reflector serial number: 1248145

Remote serial number 1248283

Date: 3/25/2019

City, ST: E. Chicago, IN

Representing: Monitoring Solutions

Representing:

COMS Flange to Flange distance (Feet / Inches): 226.125"

Preliminary Data

1	Inside diameter at Stack Exit = Lx	216.000 inches
2	Inside diameter at the Transmissometer location = Lt	216.000 inches
3	Calculated Stack Correction Factor (SCF) = Lx/Lt	1.000
4	Source-cited Stack Correction Factor (SCF)	1.000
5	Source-cited zero automatic calibration value (% opacity)	0.00 %
6	Source-cited span automatic calibration value (% opacity)	40.00 %

[START AT CONTROL UNIT / DATA RECORDER LOCATION]

(If required) [INSPECT DATA RECORDING SYSTEM AND MARK WITH "OPACITY AUDIT," AUDITOR'S NAME, AFFILIATION, DATE, SOURCE, PROCESS UNIT/STACK IDENTIFICATION, AND THE TIME OF DAY.]

Error codes / faults

		YES - or - NO
7	Blower [Loss of purge air from blower - Error 100, 300]	NO
8	Filter [Air filter restriction - Error 200, 400]	NO
9	Window [Excessive dirt on transceiver window - Error 001]	NO
10	Fault [Additional CEMS fault has occurred. Note fault code on Opacity display and consult the instrument manual.]	NO

Instrument Range Check

11 Instrument range setting 100 %

Zero Check

12 Opacity Display - Internal zero value in "milliamps" (Zero Point Check) 4.00 mA

[Wait for 1½ minutes for automatic change to external zero mode.]

13 Opacity Display - Zero calibration value in "milliamps" (Window Check) 4.00 mA

14 Opacity data recorder zero calibration value in "% Op" (Window Check) 0.00 mA

[Wait 1½ minutes for automatic change to span mode.]

Span Check

15 Opacity Display - Span calibration value in "milliamps" (Span Check) 10.40 mA

16 Opacity data recorder span calibration value in "% Op" (Span Check) 40.00 %

[Go to reflector location.]

AUDIT DATA SHEET
MONITORING SOLUTIONS DURAG D-R 290 COMS

Reflector Dust Accumulation Check

17 Pre-cleaning effluent opacity (% Op) 0.0 %
[Inspect and clean optical surface.]

18 Post-cleaning effluent opacity (% Op) 0.0 %
[Go to transceiver location.]

Transceiver Dust Accumulation Check and Zero Compensation Check

19 Pre-cleaning effluent opacity (% Op) 0.0 %
[Inspect and clean optical window and zero mirror.]

20 Post-cleaning effluent opacity (% Op) 0.0 %

Optical Alignment Check

[LOOK THROUGH ALIGNMENT SIGHT AND DETERMINE IF BEAM IMAGE IS CENTERED.]

21 Is the image centered?

YES - or - NO
YES

Zero Compensation Check

21a Did you comply with the Zero Compensation Check?

YES - or - NO
YES

Annual Zero Alignment Error Check

21b Did you comply with the Annual Zero Alignment Error Check?

YES - or - NO
NO

Zero Alignment Error Check results (if applicable):

Clear Path Value % = N/A Window Check Value % = N/A Zero Alignment Error % = N/A

[Record audit filter data.]

Filter	Serial NO.	% Opacity	SCF%
22 LOW	ZE36	15.80	15.80 %
23 MID	YB87	28.10	28.10 %
24 HIGH	YB88	45.50	45.50 %

[Remove the audit filters from the protective covers, inspect, and clean each filter]

[Set the unit up to display the initial zero. Wait 3 minutes to allow opacity data recorder to record initial zero]

[Insert a filter, wait approximately 3 minutes, and record the opacity value reported by the opacity data recorder. Repeat the process 5 times for each filter.]

[Read and transcribe final calibration error data from the opacity data recorder on the next page]

AUDIT DATA SHEET
MONITORING SOLUTIONS DURAG D-R 290 COMS

25 ZERO 0.00

	LOW		MID		HIGH		(If Required) ZERO
26	16.10	27	28.30	28	45.60	29	N/A
30	16.10	31	28.30	32	45.60	33	N/A
34	16.10	35	28.40	36	45.60	37	N/A
38	16.10	39	28.40	40	45.60	41	N/A
42	16.10	43	28.60	44	45.60	45	0.00

[Six-minute average data, if applicable.]

	ZERO		LOW		MID		HIGH		(If Required) ZERO
46	0.00	47	16.10	48	28.60	49	45.60	50	0.00

Reserved Area

Calculation of Audit Results

Stack Correction Factor correlation error (%):

1.000 1.000

51 $$\left[\frac{Blank\ 4 - Blank\ 3}{Blank\ 3}\right] \times 100$$ = 0.00

1.000

Zero Error (% Op.):

4.00 0.00

52 Opacity Display 6.25 * (Blank 13 - 4.0) - Blank 5 = 0.00 %

0.00 0.00

53 Opacity Data Recorder Blank 14 - Blank 5 = 0.00

AUDIT DATA SHEET
MONITORING SOLUTIONS DURAG D-R 290 COMS

Span Error (% Op.):

54 Opacity Display	10.40 / 100 / 40.00 (((Blank 15 - 4.0) ÷ 16) × Blank 11) - Blank 6	=	0.00 %
55 Opacity Data Recorder	40 / 40 Blank 16 - Blank 6	=	0.00

Optical Surface Dust Accumulation (% OP):

56 Retroreflector	0 / 0.0 Blank 17 - Blank 18	=	0.00 %
57 Transceiver	0 / 0 Blank 19 - Blank 20	=	0.00 %
58 Total	0 / 0 Blank 56 + Blank 57	=	0.00 %

Optical Path Length Correction (SCF)
Audit Filters Corrected for Path Length:

59 LOW: 15.80 1.000

$$1-(1-(\frac{Blank\ 22}{100})^{Blank\ 4})\ x\ 100$$ = 15.80 %

60 MID: 28.10 1.000

$$1-(1-(\frac{Blank\ 23}{100})^{Blank\ 4})\ x\ 100$$ = 28.10 %

61 HIGH 45.50 1.000

$$1-(1-(\frac{Blank\ 24}{100})^{Blank\ 4})\ x\ 100$$ = 45.50 %

AUDIT DATA SHEET
MONITORING SOLUTIONS DURAG D-R 290 COMS

Auditor: Dan Bowles Date: 03/25/19
Source: Primary Energy Unit: Stack 201

PARAMETER		Blank No.	Audit Results	Specifications
Error Codes/Faults				
Blower failure		7	NO	NO
Filter Blockage		8	NO	NO
Window		9	NO	NO
Fault		10	NO	NO
SCF Correlation Error		51	0.00	+/- 2% Op
Internal Zero Error	Display	52	0.00	+/- 4% Op
	Data	53	0.00	+/- 4% Op
Internal Span Error	Display	54	0.00	+/- 4% Op
	Data	55	0.00	+/- 4% Op
Optical Alignment Analysis		21	YES	YES = Centered
Zero Compensation Check		21a	YES	YES = Complied With
Zero Alignment Error		21b	N/A	≤ 2% Op
Optical Surface Dust Accumulation				
Retroreflector		56	0.00	≤ 2% Op
Transceiver		57	0.00	≤ 2% Op
Total		58	0.00	≤ 4% Op
Calibration Error Analysis				
Arithmetic Mean Difference				
	LOW	62	0.30	
		71a	0.30	
	MID	63	0.30	
		72a	0.50	
	HIGH	64	0.10	
		73a	0.10	
Confidence Coeffecient				
		65	0.00	
		66	0.15	
		67	0.00	
Calibration Error				
		68	0.30	≤ 3% Op
		69	0.45	≤ 3% Op
		70	0.10	≤ 3% Op

Revision: March, 2016

OPACITY LOW FILTER AUDIT

Accuracy Determination

Primary Energy | E. Chicago, IN | Stack 201 | 3/25/2019

LOW FILTER RUN	Opacity Output from Recording Device	Audit Filter Value Corrected for Path Length (SCF)	(FILTER-MONITOR) Difference	Difference^2
		RM	(X_i)	X_i^2
1	16.10	15.80	0.30	0.0900
2	16.10	15.80	0.30	0.0900
3	16.10	15.80	0.30	0.0900
4	16.10	15.80	0.30	0.0900
5	16.10	15.80	0.30	0.0900

n = 5

t(0.975) = 2.776

Mean Ref. Method Value	**15.8000**	*RM*
Sum of Differences	**1.5000**	*Xi*
Arithmetic Mean Difference	**0.3000**	*Xi ave*
Sum of Differences Squared	**0.4500**	*Xi^2*
Standard Deviation	**0.0000**	*sd*
2.5% Error Conf.Coef	**0.0000**	*CC*
Calibration Error	**0.3000**	*percent*

OPACITY MID FILTER AUDIT

Accuracy Determination

Primary Energy | E. Chicago, IN | Stack 201 | 3/25/2019

MID FILTER RUN	Opacity Output from Recording Device	Audit Filter Value Corrected for Path Length (SCF)	(FILTER-MONITOR) Difference	Difference^2
		RM	(X_i)	X_i^2
1	28.30	28.10	0.20	0.0400
2	28.30	28.10	0.20	0.0400
3	28.40	28.10	0.30	0.0900
4	28.40	28.10	0.30	0.0900
5	28.60	28.10	0.50	0.2500

n = 5

t(0.975) = 2.776

Mean Ref. Method Value	**28.1000**	*RM*
Sum of Differences	**1.5000**	*Xi*
Arithmetic Mean Difference	**0.3000**	*Xi ave*
Sum of Differences Squared	**0.5100**	*Xi^2*
Standard Deviation	**0.1225**	*sd*
2.5% Error Conf.Coef	**0.1520**	*CC*
Calibration Error	**0.4520**	*percent*

OPACITY HIGH FILTER AUDIT
Accuracy Determination

Primary Energy | E. Chicago, IN | Stack 201 | 3/25/2019

HIGH FILTER RUN	Opacity Output from Recording Device	Audit Filter Value Corrected for Path Length (SCF)	(FILTER-MONITOR) Difference	Difference^2
		RM	(X_i)	X_i^2
1	45.60	45.50	0.10	0.0100
2	45.60	45.50	0.10	0.0100
3	45.60	45.50	0.10	0.0100
4	45.60	45.50	0.10	0.0100
5	45.60	45.50	0.10	0.0100

n = 5

t(0.975) = 2.776

Mean Ref. Method Value	**45.5000**	*RM*
Sum of Differences	**0.5000**	*Xi*
Arithmetic Mean Difference	**0.1000**	*Xi ave*
Sum of Differences Squared	**0.0500**	*Xi^2*
Standard Deviation	**0.0000**	*sd*
2.5% Error Conf.Coef	**0.0000**	*CC*
Calibration Error	**0.1000**	*percent*

Primary Energy Coke | **Scans Report** | Created on : Mar 25, 2019 11:30:01

East Chicago, IN | 03/25/2019 10:31 - 03/25/2019 10:38 | STACK 201

03/25/2019	OPACITY, %	
10:31		
10:31:00	0.0	MOS
10:31:02	0.0	MOS
10:31:04	0.0	MOS
10:31:06	0.0	MOS
10:31:08	0.0	MOS
10:31:10	0.0	MOS
10:31:12	0.0	MOS
10:31:14	0.0	MOS
10:31:16	0.8	MOS
10:31:18	4.8	MOS
10:31:20	8.9	MOS
10:31:22	12.9	MOS
10:31:24	16.1	MOS
10:31:26	16.1	MOS
10:31:28	16.1	MOS
10:31:30	16.1	MOS
10:31:32	16.1	MOS
10:31:34	16.1	MOS
10:31:36	16.1	MOS
10:31:38	14.1	MOS
10:31:40	13.7	MOS
10:31:42	16.7	MOS
10:31:44	20.5	MOS
10:31:46	26.5	MOS
10:31:48	28.3	MOS
10:31:50	28.3	MOS
10:31:53	28.3	MOS
10:31:55	28.3	MOS
10:31:57	28.3	MOS
10:31:59	28.3	MOS

Status Code Definitions

MOS = MONITOR OUT OF SERVICE

03/25/2019	OPACITY, %	
10:32		
10:32:01	28.3	MOS
10:32:03	28.3	MOS
10:32:05	28.3	MOS
10:32:07	23.0	MOS
10:32:09	25.5	MOS
10:32:11	29.5	MOS
10:32:13	33.8	MOS
10:32:15	44.5	MOS
10:32:17	45.6	MOS
10:32:19	45.6	MOS
10:32:21	45.6	MOS
10:32:23	45.6	MOS
10:32:25	45.6	MOS
10:32:27	45.6	MOS
10:32:29	45.6	MOS
10:32:31	45.6	MOS
10:32:33	45.6	MOS
10:32:35	45.6	MOS
10:32:37	45.6	MOS
10:32:39	45.6	MOS
10:32:41	45.5	MOS
10:32:43	38.2	MOS
10:32:45	30.8	MOS
10:32:47	23.4	MOS
10:32:49	16.1	MOS
10:32:51	16.1	MOS
10:32:53	16.1	MOS
10:32:55	16.1	MOS
10:32:57	16.1	MOS
10:32:59	16.1	MOS

Status Code Definitions

MOS = MONITOR OUT OF SERVICE

Scans Report

03/25/2019	OPACITY, %	
10:33		
10:33:01	16.1	MOS
10:33:03	16.1	MOS
10:33:05	16.1	MOS
10:33:07	13.7	MOS
10:33:09	17.5	MOS
10:33:11	20.6	MOS
10:33:13	23.6	MOS
10:33:15	28.3	MOS
10:33:17	28.3	MOS
10:33:19	28.3	MOS
10:33:21	28.3	MOS
10:33:23	28.3	MOS
10:33:25	28.3	MOS
10:33:27	28.3	MOS
10:33:29	28.3	MOS
10:33:31	22.0	MOS
10:33:33	26.2	MOS
10:33:35	29.5	MOS
10:33:37	34.9	MOS
10:33:39	45.5	MOS
10:33:41	45.6	MOS
10:33:43	45.6	MOS
10:33:45	45.6	MOS
10:33:47	45.6	MOS
10:33:49	45.6	MOS
10:33:51	45.6	MOS
10:33:53	45.6	MOS
10:33:55	45.6	MOS
10:33:57	40.0	MOS
10:33:59	29.2	MOS

Status Code Definitions

MOS = MONITOR OUT OF SERVICE

Scans Report

03/25/2019	OPACITY, %	
10:34		
10:34:01	21.8	MOS
10:34:03	14.5	MOS
10:34:05	13.2	MOS
10:34:07	16.1	MOS
10:34:09	16.1	MOS
10:34:11	16.1	MOS
10:34:13	16.1	MOS
10:34:15	16.1	MOS
10:34:17	16.1	MOS
10:34:19	16.1	MOS
10:34:21	16.1	MOS
10:34:23	16.1	MOS
10:34:25	16.0	MOS
10:34:27	15.3	MOS
10:34:29	18.3	MOS
10:34:31	21.4	MOS
10:34:33	26.3	MOS
10:34:36	28.4	MOS
10:34:38	28.4	MOS
10:34:40	28.4	MOS
10:34:42	28.4	MOS
10:34:44	28.4	MOS
10:34:46	28.4	MOS
10:34:48	28.4	MOS
10:34:50	28.4	MOS
10:34:52	28.4	MOS
10:34:54	28.4	MOS
10:34:56	25.4	MOS
10:34:58	29.7	MOS

Status Code Definitions

MOS = MONITOR OUT OF SERVICE

03/25/2019 OPACITY, %

10:35		
10:35:00	33.6	MOS
10:35:02	38.3	MOS
10:35:04	45.6	MOS
10:35:06	45.6	MOS
10:35:08	45.6	MOS
10:35:10	45.6	MOS
10:35:12	45.6	MOS
10:35:14	45.6	MOS
10:35:16	45.6	MOS
10:35:18	45.6	MOS
10:35:20	45.6	MOS
10:35:22	38.0	MOS
10:35:24	30.7	MOS
10:35:26	23.3	MOS
10:35:28	15.9	MOS
10:35:30	16.1	MOS
10:35:32	16.1	MOS
10:35:34	16.1	MOS
10:35:36	16.1	MOS
10:35:38	16.1	MOS
10:35:40	16.1	MOS
10:35:42	16.1	MOS
10:35:44	16.1	MOS
10:35:46	16.1	MOS
10:35:48	14.4	MOS
10:35:50	14.4	MOS
10:35:52	17.3	MOS
10:35:54	20.4	MOS
10:35:56	24.2	MOS
10:35:58	28.4	MOS

Status Code Definitions

MOS = MONITOR OUT OF SERVICE

03/25/2019	OPACITY, %	
10:36		
10:36:00	28.4	MOS
10:36:02	28.4	MOS
10:36:04	28.4	MOS
10:36:06	28.4	MOS
10:36:08	28.4	MOS
10:36:10	28.4	MOS
10:36:12	28.4	MOS
10:36:14	25.1	MOS
10:36:16	26.6	MOS
10:36:18	30.9	MOS
10:36:20	35.2	MOS
10:36:22	42.8	MOS
10:36:24	45.6	MOS
10:36:26	45.6	MOS
10:36:28	45.6	MOS
10:36:30	45.6	MOS
10:36:32	45.6	MOS
10:36:34	45.6	MOS
10:36:36	45.6	MOS
10:36:38	45.6	MOS
10:36:40	45.6	MOS
10:36:42	39.7	MOS
10:36:44	32.3	MOS
10:36:46	24.9	MOS
10:36:48	17.6	MOS
10:36:50	16.1	MOS
10:36:52	16.1	MOS
10:36:54	16.1	MOS
10:36:56	16.1	MOS
10:36:58	16.1	MOS

Status Code Definitions

MOS = MONITOR OUT OF SERVICE

Scans Report

03/25/2019	OPACITY, %	
10:37		
10:37:00	16.1	MOS
10:37:02	16.1	MOS
10:37:04	16.1	MOS
10:37:06	16.1	MOS
10:37:08	15.1	MOS
10:37:10	13.1	MOS
10:37:12	16.2	MOS
10:37:14	19.1	MOS
10:37:16	21.6	MOS
10:37:19	28.5	MOS
10:37:21	28.6	MOS
10:37:23	28.6	MOS
10:37:25	28.6	MOS
10:37:27	28.6	MOS
10:37:29	28.6	MOS
10:37:31	28.6	MOS
10:37:33	28.6	MOS
10:37:35	26.0	MOS
10:37:37	28.3	MOS
10:37:39	32.6	MOS
10:37:41	36.8	MOS
10:37:43	45.4	MOS
10:37:45	45.6	MOS
10:37:47	45.6	MOS
10:37:49	45.6	MOS
10:37:51	45.6	MOS
10:37:53	45.6	MOS
10:37:55	45.6	MOS
10:37:57	45.6	MOS
10:37:59	45.6	MOS

Status Code Definitions

MOS = MONITOR OUT OF SERVICE

03/25/2019	OPACITY, %	
10:38		
10:38:01	45.6	MOS
10:38:03	45.6	MOS
10:38:05	44.7	MOS
10:38:07	34.2	MOS
10:38:09	22.8	MOS
10:38:11	11.4	MOS
10:38:13	0.0	MOS
10:38:15	0.0	MOS
10:38:17	0.0	MOS
10:38:19	0.0	MOS
10:38:21	0.0	MOS
10:38:23	0.0	MOS
10:38:25	0.0	MOS
10:38:27	0.0	MOS
10:38:29	0.0	MOS
10:38:31	0.0	MOS
10:38:33	0.0	MOS
10:38:35	0.0	MOS
10:38:37	0.0	MOS
10:38:39	0.0	MOS
10:38:41	0.0	MOS
10:38:43	0.0	MOS
10:38:45	0.0	MOS
10:38:47	0.0	MOS
10:38:49	0.0	MOS
10:38:51	0.0	MOS

Status Code Definitions

MOS = MONITOR OUT OF SERVICE

OPACITY FILTER AUDIT
* 6-minute Averages *
Accuracy Determination

Primary Energy E. Chicago, IN Stack 201 3/25/2019

6 Minute Averages	Opacity Output from Recording Device	Audit Filter Value Corrected for Path Length (SCF)	(FILTER-MONITOR) Difference	Opacity Error
		RM	(Xi)	
ZERO	0.00	0.00	0.00	**0.00**
LOW	16.10	15.80	0.30	**0.30**
MID	28.60	28.10	0.50	**0.50**
HIGH	45.60	45.50	0.10	**0.10**
ZERO	0.00	0.00	0.00	**0.00**

Primary Energy Coke

East Chicago, IN

Opacity Report

03/25/2019 - 03/25/2019

03/25/2019

Created on : Mar 25, 2019 11:55:50

STACK 201

Hour	Opac, % Minutes 0 - 5	Opac, % Minutes 6 - 11	Opac, % Minutes 12 - 17	Opac, % Minutes 18 - 23	Opac, % Minutes 24 - 29	Opac, % Minutes 30 - 35	Opac, % Minutes 36 - 41	Opac, % Minutes 42 - 47	Opac, % Minutes 48 - 53	Opac, % Minutes 54 - 59
0	3.0 SVC	3.1 SVC	3.0 SVC	2.9 SVC	2.8 SVC	2.7 SVC	2.7 SVC	2.9 SVC	2.9 SVC	2.8 SVC
1	2.9 SVC	2.8 SVC	2.8 SVC	2.8 SVC	2.8 SVC	2.8 SVC	2.8 SVC	2.9 SVC	2.8 SVC	2.7 SVC
2	2.7 SVC	2.8 SVC	2.9 SVC	2.7 SVC	2.8 SVC	2.8 SVC	2.9 SVC	3.0 SVC	3.0 SVC	3.0 SVC
3	3.0 SVC	2.9 SVC	2.7 SVC	2.6 SVC	2.6 SVC	2.8 SVC	2.9 SVC	2.9 SVC	2.7 SVC	2.5 SVC
4	2.4 SVC	2.6 SVC	2.7 SVC	2.7 SVC	2.7 SVC	2.9 SVC	2.9 SVC	2.9 SVC	2.9 SVC	2.9 SVC
5	2.9 SVC	2.9 NSA	2.9 SVC	2.8 SVC	2.8 SVC	2.6 SVC	2.6 SVC	2.8 SVC	2.7 SVC	2.9 SVC
6	3.1 SVC	3.1 SVC	3.0 SVC	3.0 SVC	2.9 SVC	2.8 SVC	2.8 SVC	2.8 SVC	3.0 SVC	3.2 SVC
7	3.2 SVC	3.0 SVC	2.7 SVC	2.8 SVC	3.0 SVC	3.0 SVC	2.9 SVC	3.0 SVC	3.1 SVC	3.1 SVC
8	3.2 SVC	3.1 SVC	3.1 SVC	3.0 SVC	3.0 SVC	3.0 SVC	2.8 SVC	2.7 SVC	2.7 SVC	3.0 SVC
9	3.1 SVC	2.9 SVC	2.9 SVC	2.8 SVC	2.9 SVC	3.0 SVC	3.1 SVC	3.0 SVC	3.0 SVC	3.1 SVC
10	3.2 SVC	3.2 SVC	3.1 SVC	3.1 SVC	1.8 MOS	21.6 MOS	11.5 MOS	0.0 MOS	0.0 MOS	14.9 MOS
11	16.1 MOS	24.6 MOS	28.6 MOS	36.4 MOS	45.6 MOS	45.5 MOS	0.2 MOS	0.0 MOS	4.7 MOS	

Status Code Definitions

MOS = MONITOR OUT OF SERVICE NSA = NO SAMPLE AVAILABLE SVC = MONITOR IN SERVICE

The average opacity period average for the day was 2.9 % for 103 periods of valid data.

The Fan was in operation for 119 periods

The maximum opacity period average for the day was 3.2 %

There were 16 periods of invalid data

APPENDIX B
AUDIT FILTER CERTIFICATION SHEETS

Monitoring Solutions
Leaders in Environmental Monitoring Systems & Services
4440 S. High School Rd., Suite D, Indianapolis, Indiana 46241 Tel: 317.856.9400

REPORT OF CERTIFICATION OF NEUTRAL DENSITY AUDIT FILTERS

Date of Filter Certification: **December 31, 2018**
Date of Filter Expiration: **June 30, 2019** **Filter Set - J**

Audit Device / Filter Slot Angle of Incidence **10** Degrees
Path-Length Correction **1.000** (Straight Stack)

Table 1: Individual Filter Certification Data

Serial Number	Opacity Value (%)	Transmittance (%)	Previous Opacity (%)	Change in Opacity (%)
YB85	8.4	91.6	8.4	0.0
ZE36	15.8	84.2	15.7	0.1
YB87	28.1	71.9	28.0	0.1
ZA33	39.1	60.9	39.1	0.0
YB88	45.5	54.5	45.5	0.0
YF62	59.7	40.3	59.7	0.0
YF66	86.3	13.7	86.4	0.1

Laboratory-Based Transmissometer
Operator

See second page for Instrument Information and Details of Certification

ATTACHMENT 3

2018 Annual Compliance Certification

Cokenergy, LLC
3210 Watling Street
Mail Code 2-991
East Chicago, Indiana 46312

April 4, 2019

Via UPS

Indiana Department of Environmental Management
Compliance and Enforcement Branch
Office of Air Quality
100 N. Senate Avenue
Mail Code 61-53, IGCN 1003
Indianapolis, IN 46204 - 2251

RE: Cokenergy, LLC – Annual Compliance Certification
Part 70 Permit No. T089-36965-00383

To Whom It May Concern:

In accordance with section B.9 of the subject permit and 326 IAC 2-7-6(5), we have enclosed the Annual Compliance Certification for the Cokenergy, LLC facility.

If you have any questions concerning this report, please contact Luke Ford, Primary Energy Director EH&S, at (219) 397-4626.

Sincerely,

Keith C. Kaufman
General Manager
Cokenergy, LLC

Enclosure

cc: Luke Ford/Primary Energy (via email)
Cliff Yukawa/IDEM (via email)

File: X:\\ 615.1

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
OFFICE OF AIR QUALITY
COMPLIANCE BRANCH
100 North Senate Avenue
MC 61-53 IGCN 1003
Indianapolis, IN 46204-2251

Cokenergy, LLC

PART 70 / FESOP PERMIT- ANNUAL COMPLIANCE CERTIFICATION

This form can be used to satisfy the annual compliance certification requirements for Part 70 sources under 326 IAC 2-7-5, 326 IAC 2-7-6(5)(C) and FESOP sources under 326 IAC 2-8-5(a)(1)(C).

SOURCE INFORMATION					
(1) Source name:	Cokenergy, LLC				
(2) Source address:	3210 Watling Street MC 2-991				
(3) City:	East Chicago	(4) State:	IN	(5) Zip code:	46312
(6) Mailing address (if different from above):					
(7) Mailing City:		(8) State:	IN	(9) Zip code:	46312
(10) Permit numbers:	T089-36965-00383	(11) Reporting Period:		1/1/2018 – 12/31/2018	
(12) Contact person:	Luke Ford	(13) Email Address:		lford@primaryenergy.com	
(14) Phone number:	219-397-4626	(15) Fax number:		219-397-8313	
(16) Comments:					

SOURCE COMPLIANCE INFORMATION	
(17) CHECK THE BOX NEXT TO EITHER (A) OR (B) BELOW. (The terms "continuous compliance" and "intermittent compliance" are defined on the Definitions page).	
(A) This source was in **CONTINUOUS COMPLIANCE** with **all of the permit terms and conditions** that impose a work practice or emission standard or requires performance testing, monitoring, record keeping or reporting based on the monitoring methods in the permit.	
(B) This source was in **CONTINUOUS COMPLIANCE** with **all of the permit terms and conditions** that impose a work practice or emission standard or requires performance testing, monitoring, record keeping or reporting based on the monitoring methods in the permit, **except** for the terms and conditions listed in the following table for which the source reported intermittent compliance.	X

IMPORTANT: If you select option (B), you must complete the following table in which you list any permit terms for which compliance was intermittent during the permit for the reporting period covered by this Compliance Certification.

(18) PERMIT TERMS FOR WHICH COMPLIANCE WAS INTERMITTENT

<table>
<tr><td colspan="2">Source Name: Cokenergy, LLC</td><td colspan="2">Source Permit Number: T089-36965-00383</td></tr>
<tr><th>Permit Term/ Condition</th><th>Description of Permit Condition</th><th>*Method Codes</th><th>Report Date/Comments</th></tr>
<tr><td>D.1.2</td><td>Sulfur dioxide emissions rate from Stack 201 shall be limited to 1656 lb/hr for a 24-hour average.</td><td>CEMS/ Calc</td><td>May 10, 2018 - On May 10, 2018 at approximately 12:15 PM, a software conflict on the redundant Modicon PLC controllers resulted in loss of control to both induced draft (ID) fans and as a result, both ID fans tripped offline. The loss of draft from both fans resulted in loss of draft to all HRSGs. With loss of draft to the HRSGs, all HRSGs were offline until draft was restored.

A root cause analysis was completed with the Modicon technical support team. The Cokenergy and Modicon team replicated the conflict in the lab and Modicon developed a firmware upgrade to address the issue. The firmware upgrade will require a brief Modicon shutdown to implement. Cokenergy developed a plan to patch the firmware and it was completed on August 7, 2018.

<table><tr><th>Date</th><th>SO_2 Exceedance [lb/hr]</th><th>SO_2 Exceedance [ton]</th></tr><tr><td>5/10/18</td><td>1,825</td><td>2.0</td></tr></table>
An Emergency Occurrence Report was faxed to IDEM on May 11, 2018 and the incident was included in the 2018 2nd Quarter Deviation Compliance Monitoring Report, dated July 17, 2018.</td></tr>
<tr><td>C.1(a)</td><td>Opacity shall not exceed an average of twenty percent (20%) in any one (1) six (6) minute averaging period.</td><td>COMS</td><td>May 10, 2018 – While restoring ID fans after the trip described above, there were three 6-minute opacity exceedances ranging from 20.6% to 43.2%. The event was included in the 2nd Quarter Deviation and Compliance Monitoring Report, dated July 17, 2018.</td></tr>
<tr><td>C.1(a)</td><td>Opacity shall not exceed an average of twenty percent (20%) in any one (1) six (6) minute averaging period.</td><td>COMS</td><td>August 7, 2018 – On August 7, 2018 at 8:06 AM after the firmware upgrade was completed on the MODICON control system for the event detailed above, ID Fan #1 tripped offline and opacity spiked which resulted in a 6-minute opacity of 23.7%. The incident was included in the 3rd Quarter Deviation Compliance Monitoring Report, dated October 19, 2018.</td></tr>
</table>

(18) PERMIT TERMS FOR WHICH COMPLIANCE WAS INTERMITTENT (Continued)

Source Name: Cokenergy, LLC		**Source Permit Number:** T089-36965-00383	
Permit Term/ Condition	**Description of Permit Condition**	***Method Codes**	**Report Date/Comments**

Method Codes:

Monitoring methods: CEMS = continuous emissions monitoring system; COMS = continuous opacity monitoring system; ST = stack test; VE = visible emissions; RK = record keeping; RR = review of records; MB = mass balance; EF = emissions factor; Insp = inspections; FA = fuel analysis; WP = work practice; PM = parametric monitoring; Calc = calculations; O = other (specify in Comments)

For Part 70 sources: The submittal by the Permittee requires the certification by the "responsible official" as defined by 326 IAC 2-7-1(34).
For FESOP sources: The notification which shall be submitted by the Permittee requires the certification by the "authorized individual" as defined by 326 IAC 2-1.1-1(1).

I certify that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete.			
Signature:		Title/Position:	General Manager
Printed Name:	Keith C. Kaufman	Date:	April 4, 2019
Phone number:	219-354-5009	Email Address:	kkaufman@primaryenergy.com

PLEASE NOTE: YOU MUST EITHER SIGN THIS FORM OR ATTACH THE CERTIFICATION FORM INCLUDED IN YOUR PERMIT.

ATTACHMENT 4

Cokenergy Preventative Maintenance & Operation Plan

Efficiency is the Best Alternative Energy

Cokenergy Preventive Maintenance and Operations Plan

3210 Watling Street, MC 2-991
East Chicago, Indiana 46312

February 26, 2019 Rev. 3

Table of Contents

Abbreviations

AM	Arcelor Mittal
APHO	Assistant Power House Operator
CAP	Compliance Assurance Plan
CEM	Continuous Emissions Monitoring
COM	Continuous Opacity Monitoring
ETS	Emissions Tracking System
FGD	Flue Gas Desulfurization system
HRSG	Heat Recovery Steam Generator
ID	Induced Draft
IHCC	Indiana Harbor Coke Company
MWT	Minimum Wall Thickness (per ASME Boiler Code)
NDT	Non-Destructive Testing
OEM	Original Equipment Manufacturer
PHO	Power House Operator
PLC	Programmable Logic Controller
PM	Preventative Maintenance
PMO	Preventative Maintenance and Operations
RCFA	Root Cause Failure Analysis
SO2	Sulfur Dioxide
SDA	Spray Dryer Absorbers
SPG	Shock pulse generator (on-line cleaning unit)
STG	Steam Turbine Generator
UT	Ultrasonic Testing
WC	Water Column (gauge pressure measurement unit)

1.0 PMO Purpose/Overview

This document outlines the Preventative Maintenance and Operations Plan (PMO Plan) for the Cokenergy facility which is located adjacent to the Indiana Harbor Coke Company. This plan has been prepared in compliance with Title V Operating Permit No. 089-36965-00383 (Air Permit). This PMO Plan has been developed pursuant to a Consent Decree with the United States, the State of Indiana, Indiana Harbor Coke Company and SunCoke Energy which was entered by the United States District Court for the Northern District of Indiana with an Effective Date of October 25, 2018 (Consent Decree).

As required by the Consent Decree, the PMO Plan details the facility's approach for exercising good operating, engineering, and air pollution control practices and for minimizing emissions and ensuring compliance with the Consent Decree. More specifically, the PMO Plan provides for the steps that Cokenergy will take to allow for the continuous operation (to the fullest extent practical) of the heat recovery steam generators and flue gas desulfurization system between planned maintenance periods and during outages with minimization of emissions. All employees and contractors of Cokenergy are required to follow the provisions detailed in this PMO plan.

2.0 Plant Description

The Cokenergy facility is located in ArcelorMittal (AM) Steel's Indiana Harbor Works in East Chicago, Indiana. The Cokenergy facility is a first-of-a-kind combined heat and power system that uses the waste heat in the flue gas from the metallurgical coke facility to produce steam and power for the AM Indiana Harbor steel mill. AM's Indiana Harbor Works is a large-scale, integrated steel mill. Within the Indiana Harbor Works, SunCoke Energy owns and operates the Indiana Harbor Coke Company (IHCC) metallurgical coke plant, consisting of four batteries of 67 coke ovens each to produce coke for AM's blast furnaces. The coke ovens are non-recovery type, which combusts the coke oven gas in the ovens as it is generated. The coke ovens exhaust the combusted hot flue gas, which must be cooled and environmentally treated, into a series of refractory-lined manifolds to collect the gas.

Cokenergy's waste heat recovery steam generators (HRSGs), arranged four per oven battery, receive and recover heat from the coke oven exhaust gas, producing power-grade steam and cooling the gas in the process. The superheated steam is used to generate electricity in a GE industrial condensing/extraction steam turbine. With the steam and power generated in this process, Cokenergy supplies electricity as well as 300 psig process steam to the AM Indiana Harbor Works. Cokenergy's Flue Gas Desulfurization (FGD) system then also environmentally treats the cooled flue gas, after it passes through the HRSGs, to remove sulfur dioxide (SO2) and particulate. Flue gas temperatures and flows, and corresponding steam flows, change depending on where a given coke battery is in its coking cycle.

The Cokenergy facility consists of:

- Sixteen (16) heat recovery steam generators (HRSGs), 4 per coke oven battery, which recover heat from the flue gas, and cool it for environmental treatment;
- Flue gas ductwork to manifold the flue gas from the HRSGs to the FGD system;

- Two (2) spray dryer absorber (SDA) vessels to allow mixing of the flue gas with sorbent to remove SO2 from the flue gas;
- A thirty-two (32) compartment pulse jet, fabric filter baghouse to remove particulate from the flue gas;
- Two induced draft (ID) fans that are responsible for pulling draft through the entire flue gas system from the ovens to the ID fans;
- One GE extraction/condensing steam turbine generator (STG), rated at 95MW, that accepts the generated steam from the HRSGs, and ancillary equipment for operation of the STG, including a 6-cell cooling tower, boiler feedwater heater, and two deaerators.

A schematic of the Cokenergy facility showing its interface with the metallurgical coke plant is shown in Figure 1.

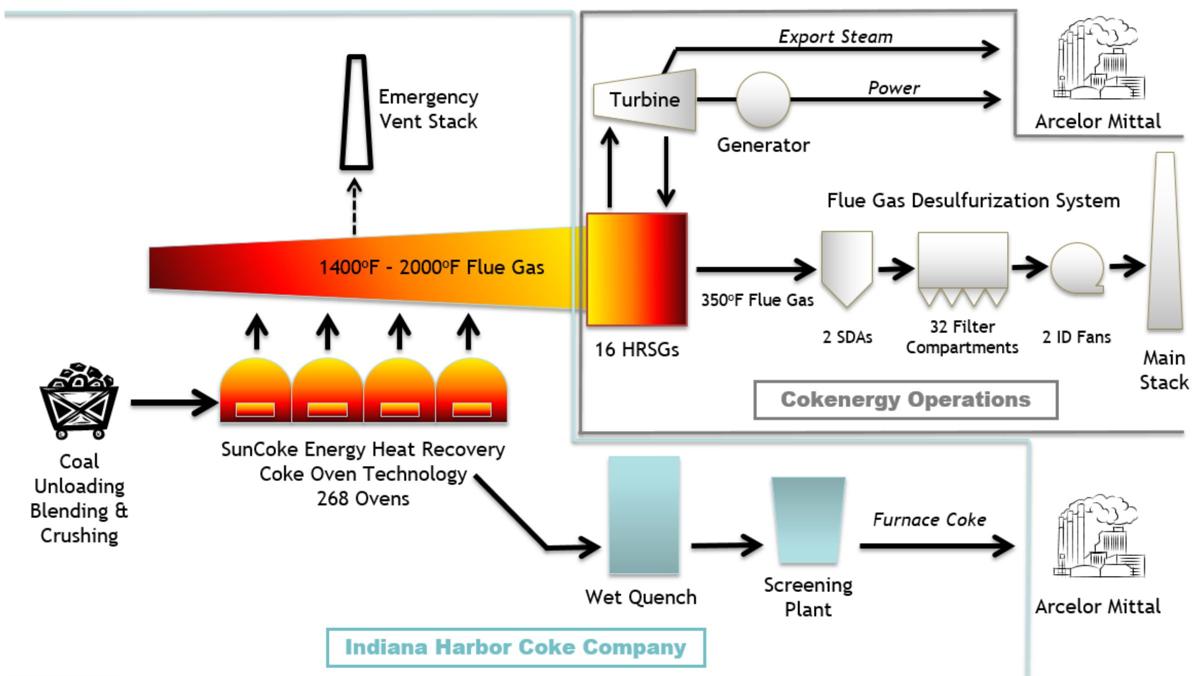


Figure 1 - Cokenergy Facility and Interface with Indiana Harbor Coke Company

The Cokenergy facility is characterized by several important features that play key roles relating to daily operation and maintenance:

- The facility operates in close conjunction with the adjacent IHCC facility. Although Cokenergy and IHCC own and operate separate equipment, the two plants are directly tied together through the flue gas path, with Cokenergy providing the induced draft for both plants, as well as environmentally treating the combusted flue gas from the metallurgical coke facility. The transition from IHCC to Cokenergy ownership is at the entrance to the inlet duct of the HRSGs.

- Induced draft from Cokenergy's ID fans allows the entire facility to operate at negative pressure (below atmospheric pressure) by providing the motive force to pull flue gas from the ovens through the HRSGs and connecting flue gas ductwork to the FGD unit. A key operational requirement is to sustain target draft at the interface between the FGD and the oven batteries to maintain the required operational draft at the ovens.
- Because IHCC's metallurgical coke ovens continuously operate, generating flue gas 24 hours a day, 7 days a week, 365 days per year, the Cokenergy facility also has a requirement to continuously operate.
- The FGD system has a 100% availability requirement per the Air Permit. This means that the FGD facility cannot be taken offline as a whole for maintenance. Due to the original design of the plant, this means that some areas of the FGD system are not accessible for routine maintenance.
- Because of the close dependence between the two plants, there is a need for daily communication between the two plants at multiple levels so that maintenance activities can be coordinated, and forced outage events can be more efficiently and quickly resolved.
- Both the Cokenergy and the IHCC facility are contractors to the AM Indiana Harbor integrated steelmaking facility as host. Both Cokenergy and IHCC ultimately provide services to AM – Cokenergy in the form of electrical power and process steam. Due to the electrical configuration of Cokenergy within the larger AM facility, Cokenergy is also dependent on electrical stability of portions of the internal AM electrical grid.

3.0 Plant Maintenance Philosophy

The preventative maintenance approach referenced herein is critical to achieve the necessary level of reliability across the environmental and environmentally-related systems. A proactive approach and the execution of appropriate preventative maintenance is a cornerstone of Cokenergy's PMO.

The following concepts are implemented throughout Cokenergy's maintenance plan:

- Incorporate a thorough preventative maintenance plan across all plant systems, with regularly established inspection and maintenance intervals.
- Define maintenance intervals and maintenance processes based on Original Equipment Manufacturer (OEM) recommendations but revise and enhance the preventative maintenance work as necessary based on practical plant experience.
- Use of an industry accepted, web-based Work Order tracking system (Maximo) to identify, schedule, and track all facility planned and break-in work.
- Maintain and regularly review inventory of critical spare parts.
- Involvement and communication of maintenance actions with all Cokenergy management, staff, operators, and contractors.

4.0 Heat Recovery Steam Generators (HRSGs)

The sixteen waste-heat recovery steam generators (HRSGs) at Cokenergy are designed to produce steam from the heat recovered from flue gas generated in a set of co-located metallurgical coking batteries. The HRSGs generate power-grade steam that is sent to an on-site steam turbine generator which produces power for end-customer AM. Each of the HRSGs was originally manufactured by Nooter/Erikson in 1997/1998 and contains both bare and finned tube heat transfer sections. Each HRSG contains a waterwall, evaporator, superheater and separate finned economizer sections as shown in Figure 2. Evaporator and evaporative water wall tubes are rolled into the main upper steam drum and two lower "mud" drums. The HRSGs are unfired, natural-circulation style HRSGs and all steam generation is developed from the waste heat in the fully combusted coke oven flue gas which is drawn through the HRSGs by the draft from the downstream ID fans. The design conditions for the HRSGs are 865 psig pressure, providing superheated steam at 725°F.

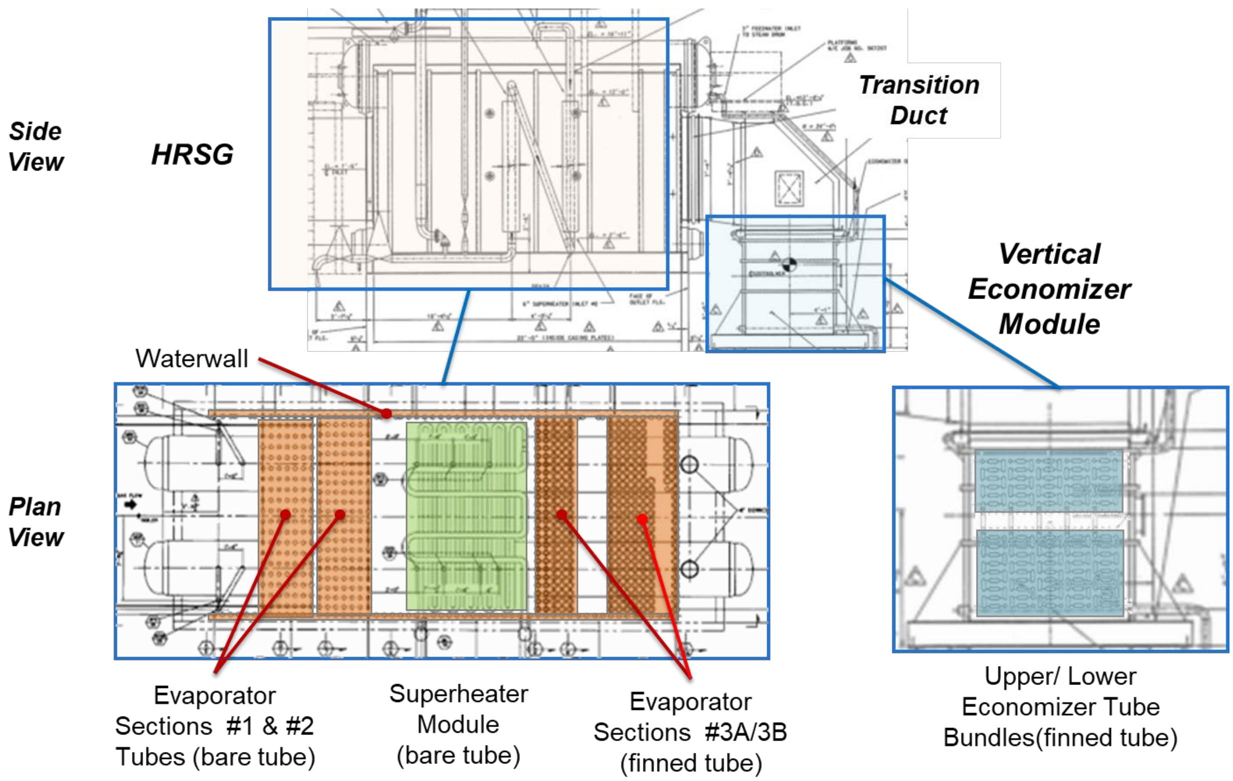


Figure 2 - HRSG Layout and Tube Surface

All sixteen of the HRSGs were retubed between 2010 and 2015, to replace the carbon steel tube materials which were thinned by repeated water washing. Off-line water washing is used to remove gas-side fouling deposits caused by the coke oven gas. Here "retube" means that all carbon steel bare, finned, and waterwall tubes were removed and replaced section by section, resulting in substantially new HRSG heat transfer circuits. The exception for replaced heating surface was the alloy superheater sections, as well as the thick-wall steam drums. Neither of these groups were shown to have experienced any noticeable material thinning.

As part of the retubing process, the specified tube thicknesses were increased, and most finned tubes sections had their fin-to-fin spacing increased to reduce the impact of fouling and improve both on-line and off-line cleaning. The replacement evaporator tubes, both smooth and finned, have been changed in material specification from SA178D to SA210C. The waterwall has been changed from SA178A to SA192. Cokenergy decided, following consultation with Nooter/Eriksen, to increase the minimum wall thickness for the evaporator tubes from 0.105” to 0.135” for re-tubing. The outer tube diameters have not been changed.

HRSG On-Line Cleaning System

Each HRSG includes an automated on-line cleaning system which operates throughout each day of operation when the HRSG is on-line. The original cleaning system is a steam sootblower system from Clyde Bergemann Power Group. The sootblower configuration incorporates six retractable sootblowers in the horizontal section, two retractable sootblowers between the upper and lower the economizer modules, and four fixed rotating sootblowers, with two above and two below the economizer modules.

Starting in 2017, Cokenergy began replacing the aging sootblower equipment with a pulsed pressure technology called Shock Pulse Generators (SPGs) offered in partnership between the OEM Explosion Power and Clyde Bergemann. The fourteen original sootblowers are removed and replaced by two SPGs which generate a gas-side pressure pulse every one-to-two hours in the HRSG flue gas stream which knocks the deposits from the heat transfer surface throughout the HRSG. This system has been proven with more than 18 months testing and evaluation to be more effective than the original steam sootblowing system. It has an additional benefit that it does not introduce additional moisture into the HRSG flue gas which can result in gas-side corrosion.

Discussion of HRSG preventative maintenance activities will be covered in the following sections. These activities can be broken down in the following areas:

- Inspection, including tube measurements (health data) – normally completed during an annual outage;
- Off-line cleaning – normally completed during an annual outage;
- Routine preventative maintenance scope which can be completed while the HRSG is on-line;
- Routine preventative maintenance scope which requires the HRSG to be off-line, and is normally completed during an annual outage;
- Tube replacement or partial retube outage, which may require outage time in addition to the normal 7-8 days for standard annual outages.

Triggers for the planning and/or initiation of maintenance activities are covered within each section.

4.1 Inspection Requirements

All HRSGs are scheduled for an annual inspection each year, completed by a third-party team specializing in boiler equipment inspections. Since these are scheduled as part of the annual outage, they do not have a separate trigger.

The inspection team photographs internal condition and key external items requiring maintenance. Internal photos provide a basis for year-to-year comparison of equipment conditions. A comprehensive inspection report is completed by the inspection team for each HRSG. Cokenergy maintains these records onsite.

As part of the inspection process, tube wall thickness measurements are taken using ultrasonic thickness (UT) measurements, or equivalent techniques, at consistent points throughout each HRSG for evaporator, superheater, waterwall sections, and economizer bends to permit routine monitoring of tube condition and wall thickness year-to-year. This process and data will be described further in Section 4.4.

HRSG inspection scope is listed in Table 1.

Table 1 - HRSG Inspection Areas

Inspection Scope	Equipment Covered	Benefit
External As-Is Assessment (Can be completed prior to unit coming offline)	• External casing and ductwork • Steel structure • Insulation • Valves/actuators • Piping • Electrical cabinets • Sample cabinets • Sootblowers or SPGs • Expansion joints	• Assess external conditions for historical record • Identify required maintenance items to be completed during planned outage
Internal As-Is Assessment – Gas Path	• Waterwall • Heat transfer tubes and finning • Casing • Refractory and insulation • Penetrations • Instruments • Doors • Gas path louver dampers	• Identify and record as-is conditions • Identify required maintenance items to be completed during planned outage • Ability to track as-is condition year-to-year
Internal Post Cleaning Assessment – Gas Path	• Waterwall • Heat transfer tubes and finning • Casing • Refractory and insulation • Penetrations • Expansion joints	• Identify required maintenance items to be completed during planned outage • Identify any new operational, wear or damage patterns
Internal As-Is Assessment – Water/Steam Path	• Main drum and mud drum interiors and internals • Heat transfer tubes	• Assess water/steam-side condition • Identify adverse impacts from water chemistry
UT tube thickness measurements (Completed in clean condition)	• Heat transfer tubes per established locations	• Track tube wear trends • Early identification of any accelerated tube thinning for proactive repair • Develop tube thickness metrics to allow predictive wear trends
Functional Testing (Completed prior to return-to-service)	• Instruments • Valves, actuators, control devices • Remote operation of controls • Remove visibility of instruments	• Test and verify all automated fail-safe control prior to return-to-service • Verify visibility of all instruments remotely in the control room prior to return to service

4.2 Maintenance Requirements

Gas-side Cleaning Process

Since the retubing of the HRSGs from 2010 through 2015, Cokenergy uses an established buffered water wash process when cleaning the HRSGs. The waterwash is required to effectively clean the HRSGs due to their original design, which include large portions of the heat transfer surface with finned tubes. This design was incorporated in the original concept for the first-of-a-kind application at the coke plant with heat recovery to maintain a small footprint for the HRSGs. However, in practice, the fouling particulate materials generated in the coking process produce deposits high in sulfur, chlorides, and alkali metals which tend to stick to the tube surfaces, and cannot be effectively removed from the finned tube surfaces except by high pressure water washing.

Because the water wash process mixes water with the highly acidic deposit materials, Cokenergy has developed a buffered wash process which mixes water with soda ash to effectively neutralize the combined waste water. The pH levels of both the wash water and the combined waste water are periodically tested to ensure that the generated waste water remains in an acceptable neutral range (pH 6-9) to minimize offline corrosion of the carbon tubes.

The cleaning contractor follows the HRSG cleaning procedure which includes monitoring of the wash and waste water. Cokenergy staff inspect all HRSGs when cleaning is completed by the cleaning contractor to confirm satisfactory condition. If the HRSG Area Manager, or designee, determines the cleaning level is not satisfactory, the cleaning contractor will complete additional washes of the required areas until inspection is acceptable. All tube surfaces are washed with mid-to-high pressure buffered water solution, followed by a final pure water rinse. All tube modules are included in the wash process.

Waste water is collected within the HRSG during the cleaning process, and then processed in Cokenergy's wash water handling area, where particulate is separated from liquid content. Liquid content is then reused as possible for subsequent washes, as long as neutral pH levels can be obtained.

Water washes will be performed at least once a year, as part of each HRSGs annual maintenance outage, where the unit is inspected prior to the cleaning, and then post-cleaning, to best understand year-to-year fouling characteristics and performance of on-line cleaning systems. Cleanings are carried out in planned, staggered pairs during the months of March through October, to avoid freezing conditions. Water washes are performed at least once every 12 months for HRSGs that have been on-line 6-months or more of the 12-month period during a calendar year. If necessary, a HRSG can be taken offline for a supplementary water wash cleaning when online instrument data indicate that the HRSG has become fouled prior to its scheduled cleaning. This may occur due to changes in coke oven coal mixtures, charge weights, or flue gas flow rates from the ovens which tend to carry more particulate from the coking process.

The order for planned HRSG cleanings are triggered based on levels of gas-side pressure drop measured across the combined HRSG and economizer sections using the installed pressure instruments at locations at the HRSG inlet and economizer outlet. A gas-side pressure drop at or above 12 inches WC indicate a HRSG shall be scheduled for cleaning. Levels between 10 inches to 12 inches WC are used to proactively pre-schedule next units for cleaning.

The Cokenergy standard HRSG Cleaning Procedure is included as Attachment 1.

Routine Preventative Maintenance Scope

In addition to the annual inspection, tube thickness measurements, and cleaning, a set of additional routine preventative maintenance tasks are assigned and completed for each HRSG at regular intervals. Many of these tasks which require internal access to the internal gas path or the internal steam/water side are scheduled during planned annual outages. There is also a routine set of preventative maintenance tasks that are completed weekly or monthly while the HRSG is online.

Annual Maintenance Outage Scope

The tasks included in the annual maintenance outage period are primarily those which require the HRSG to be offline for a planned period, usually for internal access, or for access to steam or water valves which cannot be maintained while the HRSG is on-line. These maintenance tasks are scheduled to include tasks for the HRSG cleaning and the internal as-is and post-cleaning inspections, to minimize time that the HRSG is off-line and so to minimize venting. All maintenance items as listed here are completed to ensure that each HRSG operates safely and reliably and at best efficiency within its design performance range. During each annual outage, each HRSG typically also receives its annual state inspection.

As already noted, an Annual Maintenance Outage for a HRSG includes the following key tasks:

- As-is inspection of the full unit (HRSG plus economizer);
- Water wash of gas-side of full unit;
- Clean inspection of full unit;
- Tube thickness assessment/measurements of full unit.

Additional Annual Outage maintenance tasks also include:

- Inspection and maintenance all steam- and water-side valves and actuators, including packing as required;
- Inspection and maintenance for all gas-side louver damper and isolation damper equipment, including seals and actuators;
- Inspection, calibration, and testing for all instruments, with focus on critical and/or controlling instruments such as drum level transmitters, Eye Hye independent level monitoring, inlet gas temperature thermocouples, and pressure transmitters;
- Inspection and wear-part maintenance for each unit’s on-line cleaning system SPG (or sootblowers for units where they are still in use).

Standard annual maintenance outages are planned for 7-8 days. Weather may delay completion of work or return-to-service (wind, lightning).

An example list (for HRSG D4) of standard annual maintenance work orders as scheduled in Maximo are included as Attachment 2 for reference.

It should be noted that whenever possible, unplanned work order maintenance tasks are held and completed during the planned annual outages to minimize venting time for each HRSG. The exception to this is any break-in maintenance which is required to ensure active control and reliable operation and cannot wait until the annual planned outage.

Routine Maintenance Scope Conducted Between Annual Outages

In addition to the annual outage maintenance items, there are routine preventative maintenance tasks conducted more frequently. These routine preventative maintenance activities will be scheduled based upon recommendations by the OEM, and/or based upon practical plant experience, as set forth below.

Routine, periodic preventative maintenance tasks that will be completed when each HRSG is on-line include:

- Continuous drum blowdown, which is maintained at limited continuous daily levels to ensure good water chemistry;
- Quarterly intermittent blowdowns from each mud drum, to maintain good water chemistry and eliminate possible buildup of residual in the lower (mud) drums;
- Weekly water/steam samples collected from each HRSGs sample cabinet, to allow for routine testing of water chemistry conditions;
- Completion of daily rounds by Cokenergy APHO, to identify incipient steam or water leaks at valves, as well as routine inspection of external operating equipment such as the on-line cleaning SPG units.

4.3 HRSG HEALTH DATA

As noted in Section 4.2, heat transfer tube thickness data for each HRSG is collected during each annual inspection outage. This tube thickness data, captured at a consistent set of locations for each tube module in each HRSG, form the basis for a set of HRSG health data that is collected, maintained, and monitored year-to-year for each HRSG. This data is used in the manner described below.

The tube thickness measurement data is collected using industry standard techniques for spot ultrasonic tube thickness (UT) measurements. These measurements are collected during each annual outage in a set of standardized locations in each of the HRSG tube module sections: Evaporators #1, #2, #3A, #3B, upper and lower superheaters, membrane waterwall tubes, and upper and lower economizer tube bends. The data is collected after water wash cleaning is completed and following sandblasting of the identified areas to ensure that good UT measurements can be obtained. The UT measurements are taken by the HRSG inspection team, which allows the measurements to be consistently collected by a limited number of technicians familiar with the units.

The UT data for each module of each HRSG is then uploaded and maintained in a digital database system which organizes and stores the data. The database system Cokenergy has selected is the Intertek boiler integrity management software package AWARE. AWARE is customized to collect and store the specific UT measurement data for HRSGs at the identified locations and organize it year-to-year for comparison and evaluation. Through AWARE's integrated analysis tools, the year-to-year wear rate for the tube thickness can be calculated, and thinning rates can be forecast indicating when minimum tube thicknesses would be expected to be exceeded in specific areas. This capability allows Cokenergy management to then prepare for and take planned action to repair and/or replace tube wear prior to an unplanned and potentially significant failure event. As more tube thickness data is collected year-to-year, the accuracy of this forecasted thinning rate improves, so that planned preventative repairs or limited retubes can be scheduled prior to significant failure events.

An example schematic for the location of UT measurement sections is shown in Figure 3. This schematic shows the AWARE visualization graphic for HRSG C4 Evaporator #1, with all UT tube measurement elevations indicated by a yellow X. At each elevation, three UT thickness measurements are recorded – a left, right, and center positions around the tube, as shown in Figure 4.

UT measurement data is recorded digitally by the HRSG inspection UT technician and converted to a standard MS Excel data table. The data table for each module section is included in the HRSG inspection report, and is also uploaded to the AWARE database, where it can be compared with previous year data.

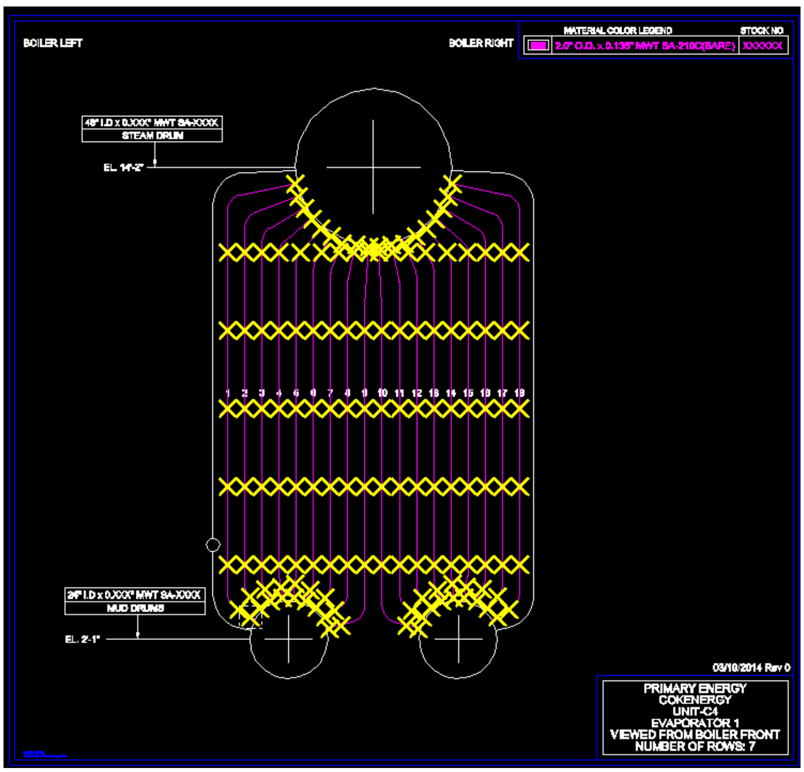


Figure 3 - AWARE Tube Thickness Location Schematic for Evaporator #1

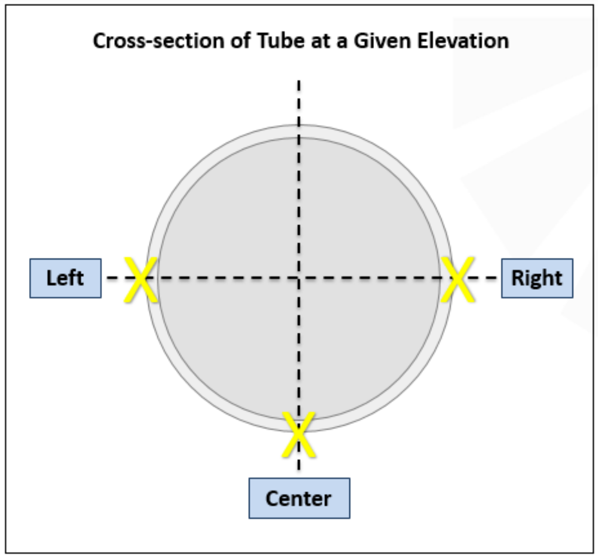


Figure 4 - UT Measurement Positions at Each Tube Elevation Location

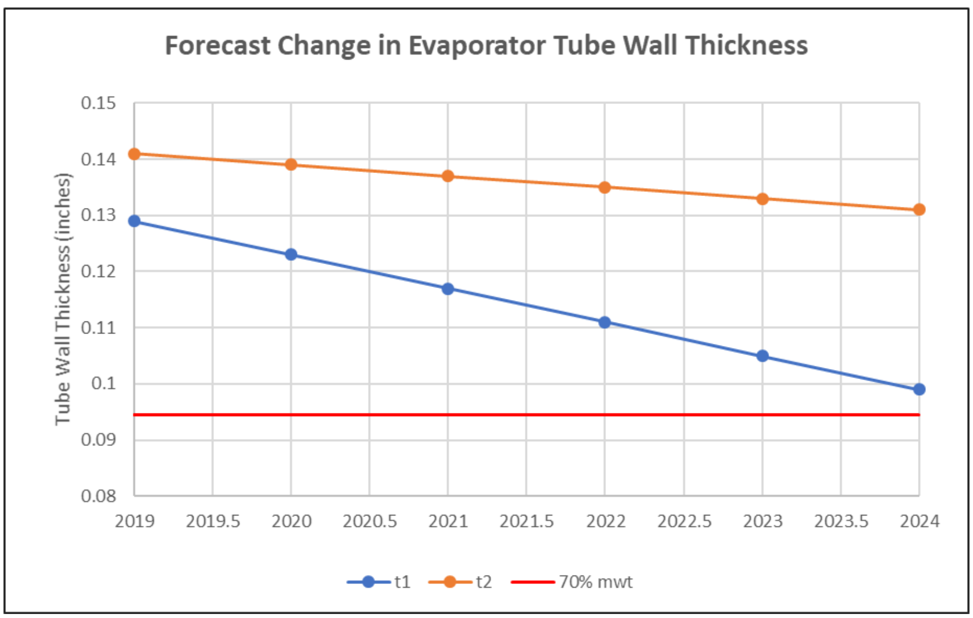
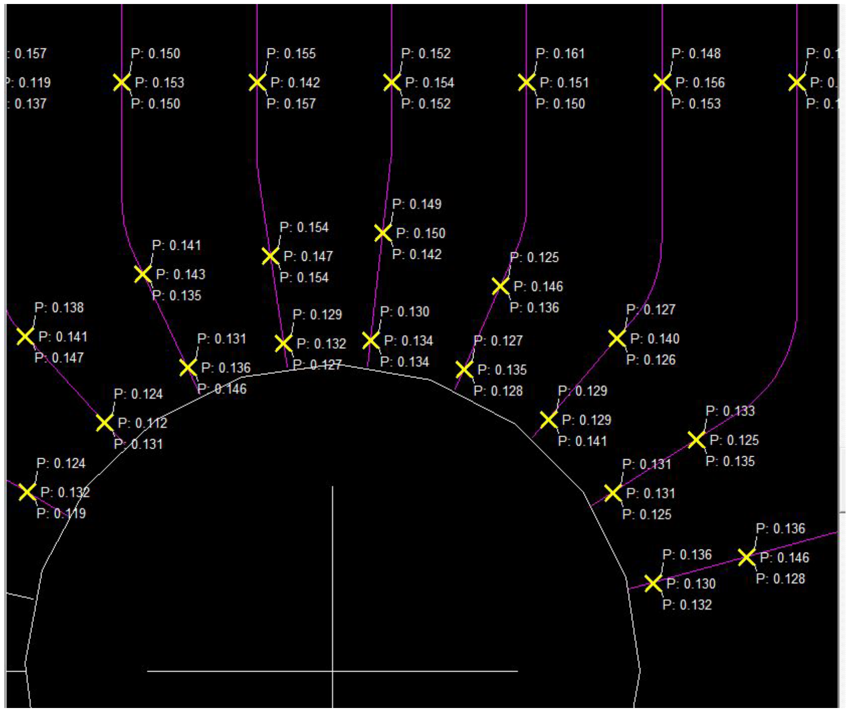
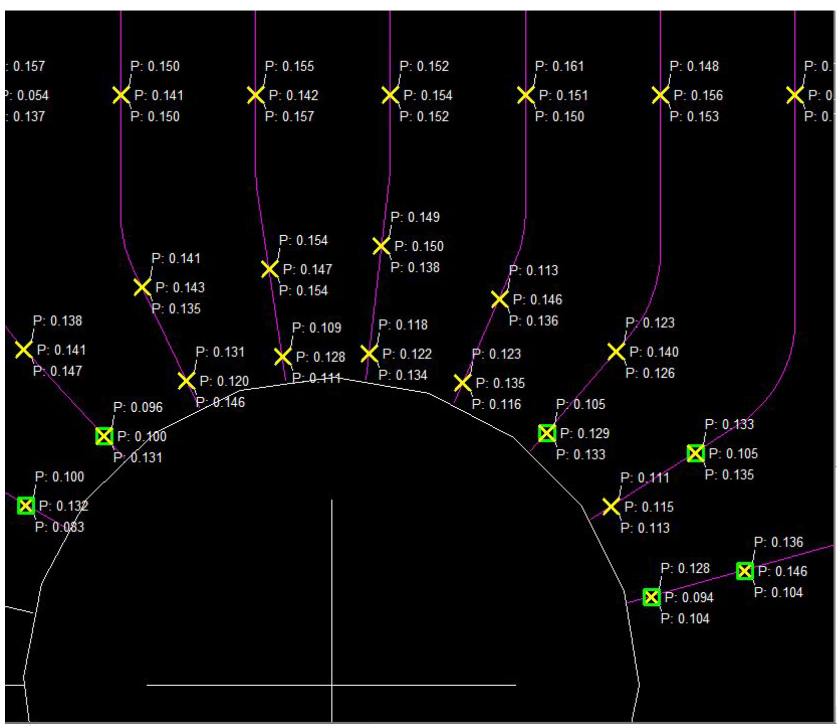


Figure 5 - Year-to-Year Forecast Change in Tube Wall Thickness



Year 2019



Year 2023

Figure 6 - Comparison of Forecast Evaporator Tube Wall Thickness

The HRSG tube UT data collected each year is used to develop tube thinning rates which AWARE can then use to forecast tube thickness levels for each identified tube location. Figure 5 provides an example of forecast tube wall thickness for one tube measurement location. Figure 6 shows an AWARE tube wall section with wall thicknesses for 2019 and 2023.

4.4 CONTROL SYSTEM

The control system for the Cokenergy HRSGs is the IHCC Bailey control system, manufactured by ABB. This distributed control system (DCS) is owned and maintained by IHCC but shared by both IHCC and Cokenergy. The Bailey system is responsible for control and monitoring IHCC controls and instruments on the oven batteries, but also includes controls for each boiler. The shared configuration for the Bailey system is due to the original plant design and the configuration and has been maintained in this format since start-up. The DCS system consists of ten (10) redundant processors that controls the IHCC facility and sixteen (16) Cokenergy HRSGs. Two HRSGs are controlled by one redundant Bailey processor. This processor also controls the associated IHCC ovens that reside below each HRSG. Total of eight redundant processors are used to control sixteen HRSGs. Bailey HRSG controls are then fed through Bailey remote I/O control cabinets located on each HRSG main platform. From each control cabinet to its associated HRSG, Cokenergy has the responsibility to maintain the network and instrument cable infrastructure to ensure reliable HRSG operation.

Cokenergy utilizes a fiber optic connection to communicate from Cokenergy's control room to IHCC's ABB Bailey system. This allows shared human machine interface (HMI) interactions between IHCC and Cokenergy. A schematic for the Bailey DCS system connectivity is shown in Figure 7.

IHCC maintains critical spares for the termination control cards and cabinet power supplies on site, and Cokenergy has access to these spares in emergency situations. In normal day-to-day maintenance situations, if Cokenergy observes operational issues with a Bailey-controlled instrument or control, Cokenergy notifies IHCC staff and coordinates with IHCC to replace and test the identified components.

Cokenergy and IHCC regularly coordinate on Bailey-related maintenance. Loss of Bailey communication and/or failure of a Bailey control component may lead to a HRSG going off-line and venting time for the affected HRSG. Because of this, Cokenergy communicates regularly with IHCC on Bailey maintenance process and schedule. IHCC schedules regular preventative maintenance of the remote Bailey I/O cabinets during planned Cokenergy annual HRSG outages.

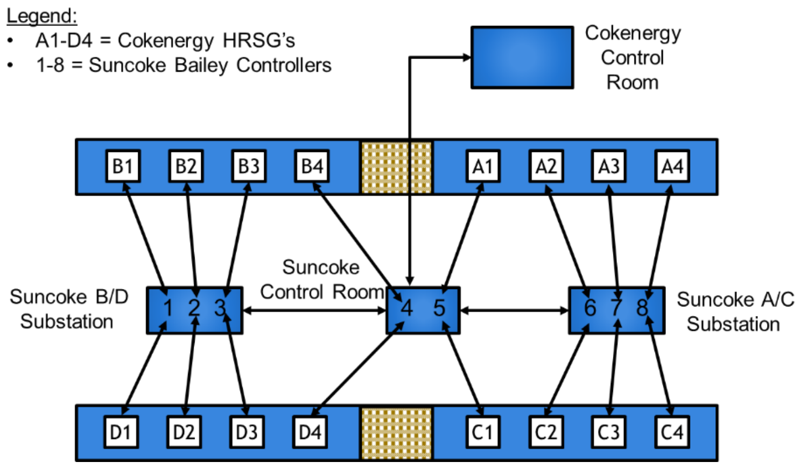


Figure 7 - Schematic of Bailey DCS Configuration for HRSG Control

4.5 Addressing Future HRSG Retube Requirements

Cokenergy maintains preparedness for possible future HRSG repairs or retubes through the following steps:

- Complete annual inspections, including completion of HRSG health tracking data (Section 4.3)
- Use collected health tracking data maintained in the AWARE database to assess current tube thinning rates and forecast future timing when tube wear rates would require tube replacements. This predictive method permits advance planning of significant retube events by routinely tracking tube condition.
- Maintain one full set of heat transfer surface tubes for each HRSG module on-site.
- Maintain embedded mechanical maintenance crews, including experienced Boilermakers and Pipefitters, for rapid response to forced outages for local and/or unforeseen failure events.

A key goal for the collection of annual tube health tracking data combined with the AWARE database is to maintain thorough monitoring data that is used to assist in early identification of tube wear patterns. The AWARE database, combined with annual visual inspections, provides the primary tool to track tube health and trigger planning for proactive repairs. Identified and monitored localized wear regions will be tracked, initiating planning for repair outages before tube failure events. These repairs can be addressed with limited tube replacements (i.e., "partial retubes" of specifically deteriorated HRSG tube sections) as opposed to large-scale retube of a full HRSG unit that would be required for significant untracked tube deterioration across the full HRSG. The scope would be defined based on the measured tube health data, in combination with visual inspection data and best practice repair methodology.

For the completion of both a partial or complete retube work scope, the existing retube quality assurance specification will be incorporated to ensure high quality process to replace tube sections.

Cokenergy will follow industry standard recommendations for replacing or repairing thinned tube sections as they are identified. An example of standard industry repair criteria is shown in

Table 3 (Reference Babcock & Wilcox Service Bulletin: Tube Thickness Evaluation Repair or Replacement Guidelines 1994).

Cokenergy triggers for tube replacement or partial retube workscope will include one or more of the following: (note *t* in Table 3 = mwt as defined below per ASME Boiler and Pressure Vessel Code).

Criteria	**Tube Wall Thickness (per %mwt trigger)**	**Action**
Measured tube thickness <mwt on single isolated tube	Superheater: 0.066 inch Evaporator: 0.059 inch Economizer: 0.082 inch	Single tube replacement at current outage
Measured tube thickness <mwt on 3 or more tubes in a module	Superheater: 0.066 inch Evaporator: 0.059 inch Economizer: 0.082 inch	Partial retube addressing affected tubes and any necessary adjacent tubes at current outage
Forecast of tube thickness <mwt on single isolated tube within next 12 months	Superheater: 0.066 inch Evaporator: 0.059 inch Economizer: 0.082 inch	Single tube replacement at next planned outage
Forecast of tube thickness <mwt on 3 or more tubes in a module within next 12 months	Superheater: 0.066 inch Evaporator: 0.059 inch Economizer: 0.082 inch	Partial retube addressing affected tubes and any necessary adjacent tubes at current outage
mwt = minimum tube wall thickness per ASME BPVC Section VIII Div 1 Superheater mwt = 0.066 inch Evaporator mwt = 0.059 inch Economizer mwt = 082 inch		

Timelines for partial retubes are dependent on scope and location for repairs and are expected to require between 5-18 days.

Guidelines for Tube Repair/Replacement

Location	Actual Tube Wall Thickness Relative to Percent Specified Wall Thickness, t	Course of Action
1. Furnace Support Tubes and Economizer Stringer Support Tubes	Tubes equal to or greater than 85% t	Monitor thickness
	Tubes less than 85% t	Restore tube wall thickness or replace tube*
2. Economizer, Furnace Wall and other Water-Cooled Tubes	Tubes equal to or greater than 70% t	Monitor thickness
	Tubes less than 70% t	Restore tube wall thickness or replace tube*
3. Superheater, Reheater and Other Steam-Cooled Tubes	Tubes equal to or greater than 85% t	Monitor thickness
	Tubes less than 85% t	Restore tube wall thickness or replace tube*

*It is difficult to restore the wall thickness for tubes below .090 inch due to possible weld burn through and distortion. On Kraft Recovery boilers, Refuse boilers, and boilers operating below 1000 psig the tubes should be replaced when below the ASME minimum wall thickness.

Table 3 - Tube Thickness Repair and Replacement Guidelines

4.6 Emissions Minimization

Cokenergy will practice emissions minimization through the following steps:

- Completion of routine inspection, cleaning, and preventative maintenance, as described in Sections 4.1-4.2.
- Maintain critical spare parts in-house (inventory) for repairs to return HRSG to service at best possible time.
- Proactive monitoring of HRSG tube health data as detailed in Section 4.3.
- Maintain sufficient dedicated maintenance crew (mechanical and electrical) to allow for best possible repair of break-in maintenance items.
- Minimize venting by combining scheduled work order tasks whenever possible that require a HRSG to be off-line. A key example of this is parallel completion of annual maintenance outage with annual cleaning and inspection work scope.
- Follow established best practice for equipment start-up and shutdowns to minimize long-term impact for cycling of equipment.

Critical spares will be determined based on OEMs recommendations and plant experience. Spare replacement sections for each heat transfer tube module are maintained onsite for efficient repairs in the event of significant tube leak events, allowing shortest possible impact on venting.

Examples of critical spare parts include:

- Replacement tube inventory for all evaporator, superheater, and economizer tubes;

- Instrumentation required for boiler control (e.g. drum level transmitters);
- Primary control valves and actuators (e.g. feedwater flow control valve);
- Start-up and safety valves.

Whenever possible Cokenergy also works to coordinate planned maintenance tasks with IHCC tasks which also require the HRSG to be off-line or vent stack lids to be open. An example of this is the cleaning of the Bailey control system cabinets on each HRSG, that also control IHCC oven damper controls and instruments. Cokenergy regularly communicates planned outage schedules with IHCC, and then IHCC completes annual Bailey cabinet maintenance while the HRSG is off-line for its annual maintenance outage.

5.0 Flue Gas Desulfurization System (FGD)

The Cokenergy Facility is equipped with a Flue Gas Desulfurization (FGD) System that is designed to remove the emissions and particulate matter from the coke oven flue gas before emitting it to atmosphere from the main (201) stack, see Figures 8 and 9. The system is designed to remove sulfur dioxide (SO_2) and particulate matter generated during the coking process as per the original plant design. The FGD system consists of two (2) spray dryer absorber (SDA) vessels followed by two (2) baghouse modules, each with 16 pulse jet fabric filter compartments. Flue gas from the coke oven batteries is first cooled by passing through the HRSGs. This cooled flue gas stream is then manifolded together into flue gas ductwork for each battery, and finally into the single main cross-over duct that delivers the flue gas to the FGD system. Sulfur dioxide scrubbing is accomplished in one or both SDAs, while particulate is removed in all 32 of the baghouse compartments, which are arranged in parallel between the two modules. Finally, the cleaned flue gas is pulled through the two (2) ID fans, exiting at the main stack downstream of the fans.

SO_2 reduction is accomplished by intimately contacting an atomized slurry concentration of calcium hydroxide ($Ca(OH)_2$) with the SO_2 laden gases while simultaneously allowing the hot flue gases to dry the reaction products. These dry reaction products are collected with the coke oven process particulate in the baghouse. The calcium hydroxide is also known as slaked lime or hydrated lime.

Cokenergy will operate the two SDAs within the FGD system concurrently, to the extent practicable, in a manner that achieves an annual reduction in SO_2 emitted from the facility to 6,165 tons/year. Cokenergy will operate the FGD system in accordance with the PMO Plan to allow equipment inspection, repair, and preventive maintenance, in a manner consistent with good air pollution control practices.

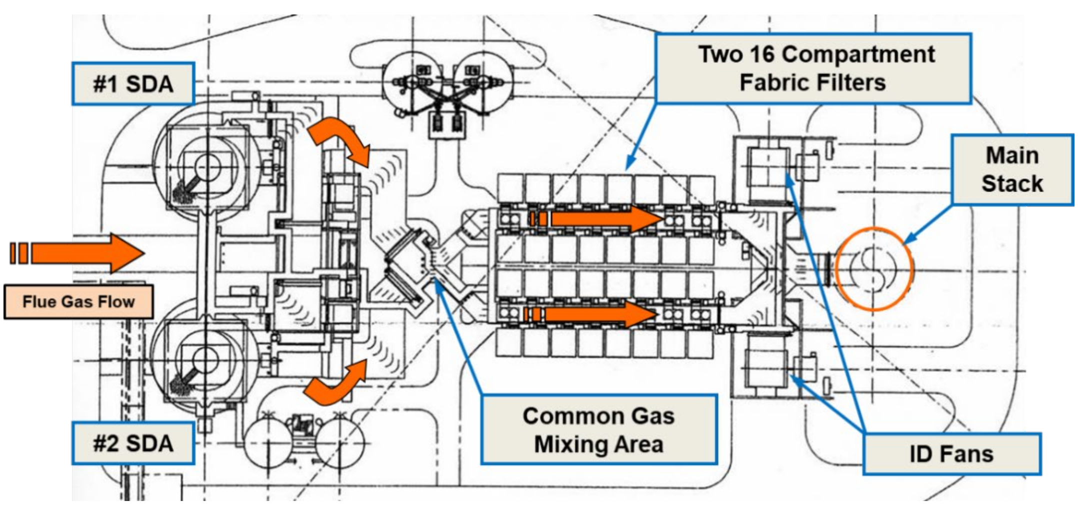


Figure 8 - Plan View of Flue Gas Desulfurization System

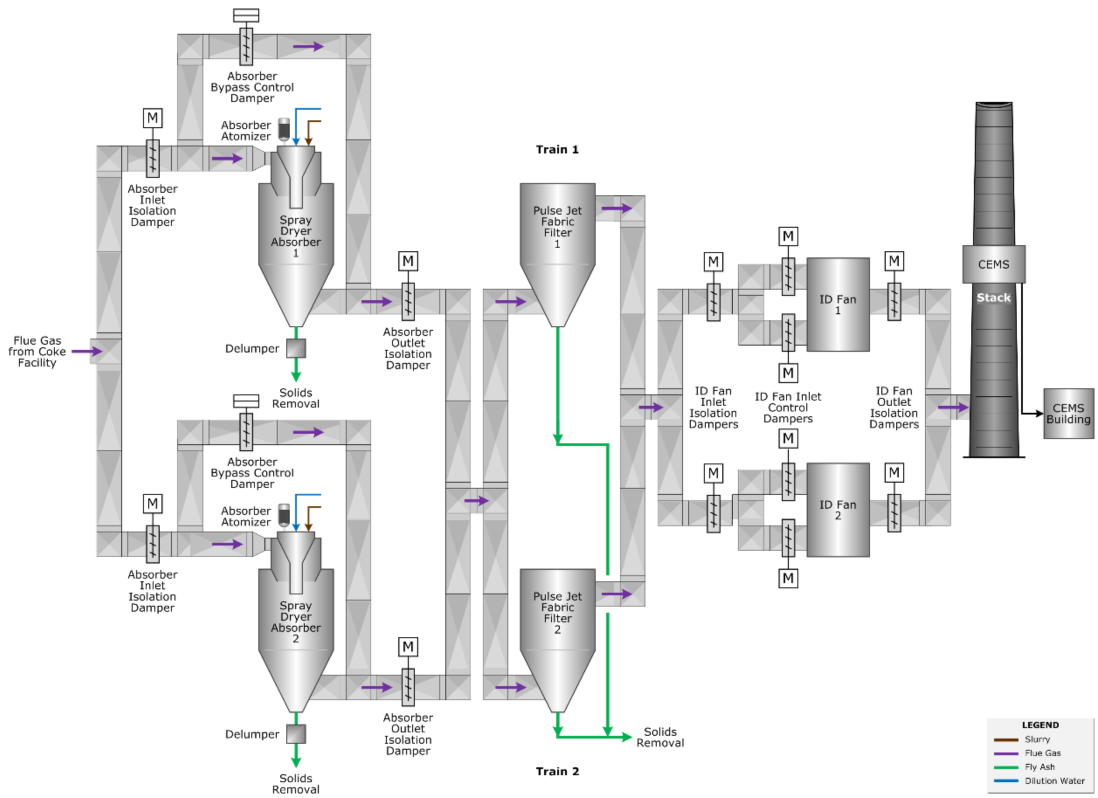


Figure 9 - Schematic of Flue Gas Desulfurization System

5.1 Spray Dryer Absorber (SDA)

The Spray Dryer Absorbers (SDAs) provide the system with the means for effectively removing sulfur dioxide (SO_2) from the flue gas stream by mixing a lime slurry sorbent solution with the flue gas. The reacted particulate byproduct is then removed in the downstream baghouse subsystem.

There are two SDAs manufactured by Marsulex Environmental Technologies (MET) consisting of a large mixing vessel with a gas inlet scroll at the top of the vessel, a rectangular outlet duct near the bottom of the vessel, and conical bottom hopper to collect dropout. Each vessel accommodates a single central spray atomizer located at the top of the vessel, in the center of the gas inlet. The atomizer receives dilution water and lime slurry and sprays this mixture into the surrounding flue gas entering the top of the vessel to complete the SO_2 removal process. Flue gas is accelerated through the scroll as well as a set of fixed turning vanes designed to create a swirling gas pattern as the gas is introduced into the SDA vessel, to benefit mixing. The calcium hydroxide in the lime slurry liquid sorbent, atomized as small droplets, mixes with the swirling flue gas stream. The SO_2 in the flue gas reacts with the calcium hydroxide, forming calcium sulfite and calcium sulfate. The reacted mixture, contained in the small droplets, then dries in the flue gas and is subsequently captured and collected in the downstream baghouse.

Rotary centrifugal atomization is employed for slurry introduction into the hot flue gas. The atomizers are induction motor-driven machines that are designed to operate under high-speed, high temperature, abrasive conditions. Due to these operating conditions, it is critical that the atomizers maintain proper lubrication, cooling, and cleanliness. These conditions are monitored and maintained through the Modicon control system. The atomizer subsystem includes an automatic oil lubrication system, a cooling water system (chiller), and a slurry piping flush system. The rotary atomizers utilize variable frequency drives for start-up, although they are operated at full speed at approximately 8,000 rpm.

Each Cokenergy SDA vessel is sized to treat up to 100% of the design flue gas flow from the oven batteries. The SDAs and all downstream equipment are routinely exposed to corrosive acid gases and require frequent inspection and maintenance to minimize corrosion and maintain the integrity of pollution control equipment. Inspections and maintenance will be performed in accordance with Tables 4 and 5 below.

Operational Modes – Single and Dual

The SDA units can be operated either in single or dual operational modes. For single operational mode, all flue gas transferred from the oven batteries passes through a single SDA vessel, with a single atomizer operating for this vessel. In this mode, the second vessel is isolated using the inlet and outlet guillotine isolation dampers (See Figure 9). In single mode, either SDA - #1 or #2 – may be operated.

In dual mode, both SDAs are operated in parallel, with the flue gas from the batteries splitting evenly between each SDA unit, and all isolation dampers in the open position. In dual mode, two atomizers are in operation – one for each vessel. The flue gas is split between the vessels resulting in reduced gas load to each atomizer, and reduced lime and water flows to each atomizer. This also improves spray drying performance because it results in increased residence times for sulfur reaction and increased drying time for the byproduct particulate.

The ability to operate in single mode is critical to allow preventative maintenance of the SDA vessels. Operation in single mode on one vessel allows the other vessel to be isolated and locked out through standard lockout/tagout process, permitting both the atomizer as well as the interior of the SDA vessel to be accessed for inspection and/or maintenance.

Routine Inspection Requirements

Inspection areas for the SDA include not only the SDA vessel itself, but the atomizer and the control and isolation dampers for each SDA. The vessel internals can only be inspected when the SDA is offline, isolated, and locked out. Redundant seal air fans (2 per isolation damper) ensure that a man-safe mechanical and air seal are maintained to allow entrance to the vessel.

Table 4 - SDA Inspection Areas

Inspection Scope	Equipment Covered	Frequency
Atomizer motor/lower assembly	• Atomizer motor • Atomizer lower assembly • Atomizer wheel and tiles • Water and slurry connections • Electrical connections • Instrument connections • Motor/assembly coupling	• Atomizer operational swap • Atomizer motor maintenance (approx. 6500 runtime hours) • Atomizer assembly maintenance (approx. 4000 runtime hours)
SDA Vessel	• Manway access doors • Vessel wall interior • Hopper internal walls • Gas scroll ductwork • Scroll flue gas turning vanes • Inlet distribution control dampers	• Annually
SDA Vessel and Key Ductwork	• SDA vessel and ductwork corrosion coupons	• Monthly or Bi-monthly
Isolation Dampers	• Internal seal surface on isolation side • Expansion joint on insolate side • Seal air fan assemblies	• Annually • Damper surface can be inspected externally in the open position as convenient
Atomizer Chiller (Cooling Water Unit)	• Refrigeration units/compressors • Fans • Air filters • Coolant fluid	• Quarterly
Atomizer Lube Oil System	• Pump • Solenoid	• Semi-annually

Routine Maintenance Requirements

As with inspection, maintenance areas for the SDA include not only the SDA vessel itself, but the atomizer and the control and isolation dampers for each SDA, as well as ancillary systems (lube oil and cooling water). The vessel internals can only be inspected when the SDA is offline, isolated, and locked out. Redundant seal air fans (2 per isolation damper) ensure that a man-safe mechanical and air seal are maintained to allow entrance to the vessel.

Table 5 - SDA Maintenance Areas

Maintenance Scope	Equipment Covered	Frequency	Maint. Trigger
Atomizer motor	• Atomizer motor • Electrical connections • Instrument connections • Mechanical seal • Bearings • All OEM-identified wear parts	• Approx. 6500 runtime hours nominal, 7500 runtime hours max • Timing may vary depending on operational loads and conditions	• Shop overhaul at designated runtime limits (Freq. Col.) • Shop inspection/ overhaul for elevated motor vibration levels (> 0.5ips)
Atomizer lower assembly	• Atomizer wheel, tiles, and nozzles • Water and slurry connections • Instrument connections • Spindle assembly • Bearings • Lower "spider" water and lime distributor assembly • Air vent	• Approx. 4000 runtime hours nominal, 7500 runtime hours max • Timing may vary depending on operational loads and conditions	• Field overhaul (bearings/spindle) at designed runtime limits (Freq. Col.) • Field overhaul for elevated vibration levels • Shop overhaul and reconditioning at 5-year intervals
SDA Vessel and Ductwork	• Manway access doors • Vessel wall interior • Hopper internal walls • Gas scroll ductwork • Scroll flue gas turning vanes • Inlet distribution control dampers • Expansion joints	• As required	• Repair corrosion damage identified as surface rust, wall thinning and/or pin holes, prior to progression • Replace exp. joints when found worn or with tear(s)
Atomizer Chiller (Cooling Water Unit)	• Filters • Glycol reservoir/supply • Compressor	• Quarterly	• Service compressor with excessive cycling • Service pump at low flow performance
Atomizer Lube Oil System	• Pump • Solenoid • Clean oil reservoir	• Quarterly	• Service pump at low or inconsistent flow or pressure performance • Replace solenoid for inconsistent control action
Isolation Dampers	• Damper internal flex seal assembly • Expansion joint • Seal air fan assemblies	• As required	• Replace seals when damaged on inspection. • Repair/replace seal air fans at low flow • Replace exp. joints when found worn or with tear(s)

It must be noted here that, due to the original design of the MET SDA equipment, there are certain areas that cannot be individually isolated; therefore, they cannot be inspected or maintained internally unless the entire FGD system is offline.

These areas include:

- The inlet flue gas ductwork to the SDAs upstream of the inlet guillotine isolation dampers;
- The SDA outlet ductwork downstream of the SDA outlet guillotine isolation dampers;
- The expansion joints in the noted ductwork.

These areas were last inspected during the May 2015 FGD outage. Inspections of the areas listed above shall be conducted during each scheduled maintenance outage, unless previously inspected within 5-6 years. These outages, generally requiring outage durations between 3-5 days, are scheduled to maintain the integrity of the equipment and avoid catastrophic failure that would result in longer shutdown timeframes and more venting. Repairs identified during the inspection outage will be completed during the same outage event.

5.2 BAGHOUSE

The Baghouse is located downstream of both SDAs and is designed to remove particulate material from the flue gas and is a standard pulse jet fabric filter design. A small portion of the collected particulate is carried from the coke oven process, but the majority of the particulate is formed as a byproduct of the SO_2 removal process. Removal of the particulate matter is accomplished via filter bags arranged in modules that are installed in the flow path between the SDA and the ID Fans. The baghouse consists of 32 filter compartments arranged in two parallel modules of 16 compartments each (1A-1P, 2A-2P). Each compartment is equipped with 272 bags, each with a diameter of 6 inches and a nominal length of about 16.33 ft. In normal operation, flue gas flows to each of the baghouse compartments. As the flue gas passes through the filter bags, particulate accumulates on the outside of the filters and cleaned flue gas exits the baghouse compartments and then continues through the ID fans to the stack. The filter bags are rated to operate continuously at temperatures up to 320°F with short-term excursions of up to 400°F. Gas temperatures to the baghouse are controlled through dilution water cooling introduced though the SDA atomizers, maintaining mixed gas temperature to the baghouse in the range of 250ºF – 280ºF.

Filter bags are a PPS needle felt fabric, typical for the baghouse industry, which is then dipped in a PTFE emersion bath to improve characteristics of particulate penetration and release. When installed, filter bags are cleaned using a distributed pulsed air system, again typical for industrial fabric filter baghouses. Pulse cleaning for the baghouse compartments is completed on an automated offline cycle. This automated program cycles through the 16 individual compartments in a module when the gas-side pressure drop on a given module reaches a defined target maximum, set for 8.5 inches WC.

It is possible during normal operation to remove 1-2 compartments from service from each baghouse module to allow these compartments to be isolated for internal maintenance.

Inspection Requirements

Several routine inspection tasks are periodically executed for the baghouse. The primary inspection is a quarterly inspection of all 32 baghouse compartments each year by a third-party company experienced with pulse jet fabric filter design, equipment, and operation. This inspection is completed by systematically taking 1-2 compartments offline, isolating and locking out each compartment, followed internal inspection by an experienced crew.

The quarterly inspection assesses and documents:

- Filter bag condition for all compartments;
- Compartment clean gas-side condition for all compartments;
- Compartment dirty gas-side condition, including the compartment hopper, for a portion of the total – typically 8 of 32.
- Identified broken/damaged bags replaced in each compartment during the inspection.

During this compartment-by-compartment inspection, if a filter bag and/or cage is found to be damaged, it is documented, and then replaced. The contractor completing the inspection documents results for all compartments, including any compartments exhibiting damage or unexpected conditions.

Other triggers for baghouse compartment repairs include the following:

- Repeated or unresolved high compartment levels;
- Lower than normal compartment pressure drop recovery following cleaning (normal, expected recovery ranges between 1”-2.5” WC, depending on compartment location);
- Internal compartment wall corrosion marking or penetrations noted upon visual inspection.

Maintenance Requirements

<u>Accessible Components/Areas</u>

The following maintenance tasks are routinely completed through normal subsystem de-energization and lockout/tagout process.

- Annual replacement of filter bags in the eight compartments with the longest runtime since the last filter bag change-out. This process is completed yearly since the PTFE-coated PPS filter bags in use at Cokenergy have been found to have a 3-4 year life cycle for the flue gas conditions experienced at Cokenergy (primarily flue gas oxygen levels combined with gas temperature levels). This annual process replaces the oldest set of filter bags to provide a systematic replacement process that can be scheduled and budgeted year-to-year.
- Replacement of baghouse compartment hopper swing disc assemblies, due to wear part deterioration with use. Swing discs provide the means to evacuate the calcium sulfate byproduct from a compartment hopper following a given number of pulse cleaning cycles. The swing discs are part of each baghouse compartment, and due to the fine, erosive nature of the byproduct particulate, require replacement of key moving wear parts on a 6-12 month average basis to remain in good working order. This is accomplished by swapping a swing disc at the end of its operational cycle with a spare rebuilt disc in inventory.

- Periodic – and typically long-term – repair of internal and/or external compartment weld cracking or localized corrosion locations to maintain air-tight seal and avoid infiltration of ambient air.

Inaccessible Components/Areas

It must be noted here that, due to the original design of the MET baghouse equipment, there are certain areas that cannot be individually isolated, therefore they cannot be inspected or maintained internally unless the entire FGD system is offline.

These areas include:

- The inlet flue gas ductwork between the SDA outlet guillotine isolation dampers and the inlet the baghouse module;
- The dirty flue gas distribution plenum to the compartments for each module;
- The clean flue gas collection plenums from the compartments for each module;
- The inlet damper assemblies for each compartment;
- The outlet poppet dampers for each module;
- The downstream ductwork from the baghouse outlet to the inlet guillotine isolation damper for each ID fan;
- Turning vanes in each of the ductwork areas mentioned above.

Due to lack of access, and inability to isolate while the FGD is in operation, these areas are not routinely inspected. Internal damage in these areas would require a full plant outage to access and repair. It should be noted that these areas were last accessed and inspected in the planned full plant outage in May 2015. Duct and turning vane repairs identified in these areas were repaired at that time. These inaccessible areas and components will be inspected and maintained as needed every 5-6 years. These outages, generally requiring outage durations between 3-5 days, are scheduled to maintain the integrity of the equipment and avoid catastrophic failure that would result in longer shutdown timeframes and more venting. Repairs identified during the inspection outage will be completed during the same outage event.

5.3 Induced Draft Fans

The Induced Draft (ID) Fans provide the motive force to draw flue gas from the coke ovens, through the 16 HRSGs, SDAs, and baghouse compartments, and discharge the gasses out a common exhaust stack. The facility is equipped with two ID fans, situated in parallel downstream of the baghouse modules. The fans are connected by a common header downstream of the baghouse modules so that the fans may operate in tandem, or either single fan may operate and handle flue gas flow from both baghouse modules while the other fan is isolated. The original equipment supplier is TLT-Babcock. OEM support for the fans is now provided through Howden.

The fans are designed for an inlet flue gas flow of 605,090 scfm with an inlet temperature of up to 300°F, with short-term excursions at up to 500°F. The two fans are installed in parallel and are each equipped with two inlet ducts and one discharge duct. The fans discharge into a common header that directs the flue gases to atmosphere through a single exhaust stack. Motor operated isolation dampers are installed upstream and downstream of each ID fan providing positive isolation for maintenance.

During operation both the inlet and outlet isolation dampers are fully open and the inlet louver control dampers modulate to adjust flow through the fans and draft to the upstream portions of the Cokenergy and IHCC facility. During normal operation, both fans are in service.

Each fan is equipped with an identical, independent, lube oil system, used for lubricating the fan bearings. The lube oil system is equipped with two motor driven pumps, one for operation and the other for redundant standby.

Each fan is driven by a 7500 HP, 13.8 kV AC motor. Each motor is equipped with a fixed bearing located between the motor and the fan. The motor is equipped with shaft mounted fans that circulate air to cool the motor windings as it operates. The fan housing is equipped with air filters that prevent dust and contaminants from entering the motor with the circulating cooling air flow. A differential pressure switch (PDS) is installed and will provide an alarm indicating that the filters require service.

For further redundancy, a spare ID fan motor is maintained in "ready-to-install" condition in environment-controlled storage operated by the motor repair vendor. This fan can be transported to the plant for installation within one day, with swap out of motors typically taking two days.

Routine Inspection Requirements
Several standard inspection tasks are routinely completed for the ID fans. However, internal inspections can only be completed when the fan is offline, isolated and locked out. These are completed once a year, or as required based on performance monitoring. Performance data monitored for each ID fan includes inboard/outboard bearing temperatures, inboard/outboard bearing temperatures, and motor winding temperatures. OEM or third-party inspection of the ID fan internals will be completed on five-year cycles. The last inspection of ID fan internals was completed in 2015.

Internal inspection tasks will include:

- Inspection of inlet scroll section
- Inspection of rotor
- Inspection of all guide and turning vanes
- Inspection of motor electrical connection cabinet
- Inspection of motor windings and cable connections
- Inspection of lube oil units
- Inlet and outlet isolation dampers

There may be some inspections during which it will not be possible to inspect one or more of the above items. However, all items that can be inspected will be inspected.

External inspections will be completed as part of normal daily/weekly walkdowns:

- Visual external inspection of lube oil units
- Visual inspection of louver damper linkage
- Visual inspection of all external casing and electrical cabinets
- Visual inspection of inlet and outlet isolation dampers

Routine Maintenance Requirements
Preventative maintenance for the ID fans primarily focuses on routine external maintenance of the ID fan motors and lube oil skids.

Routinely scheduled preventative maintenance shall include:
- Replacement of ID fan motor air filters, at least on a quarterly basis, but also when indicated by filter pressure drop;
- Maintenance of oil level and condition of the ID fan lube oil skids.

Internal ID fan maintenance and repairs if necessary will be coordinated with the appropriate OEM or experienced third-party vendors. In the event of an ID fan motor failure, the standby motor will be requested from the storage facility, the out-of-service motor will be disconnected and lifted from the motor pedestal, and the standby motor will be installed in its place. The failed motor will be sent to the motor repair vendor, and once repaired, returned to storage as the new standby unit.

Internal areas of the ID fan duct work and isolation dampers were inspected in the May 2015 FGD outage. Internal inspections of the areas listed above shall be conducted during each scheduled FGD maintenance outage, unless previously inspected within 5-6 years. These inspection outages, generally requiring durations between 3-5 days, are scheduled to maintain the integrity of the equipment and avoid catastrophic failure that would result in longer shutdown timeframes and more venting. If planned inspections identify required repairs for the ID fans or the respective insolation dampers, these will be coordinated with the inspection outage and are anticipated to require 8-10 days of maintenance outage time.

5.4 Control System
The control system for the FGD system is a Modicon PLC system, manufactured by OEM Schneider Electric. This system consists of a Primary and Secondary (Hot Standby) redundant controller and twelve (12) Remote input/output (I/O) racks. The Modicon controls the facility’s ID Fans, Baghouse, Spray Dryer Absorbers, and FGD auxiliary support systems. The Modicon control system is the original FGD control system, but components were upgraded in 2015. Improvements implemented in the upgrade include new controllers along with replacement of obsolete coaxial communication cables to remote I/O locations. New controllers have enabled improvements to automation software as prior to 2015, the original controllers were fully utilized, preventing programing and automation enhancements. Remote I/O communication coaxial non-redundant cables were replaced with redundant, self-healing, fiber optic cables.

The Modicon configuration diagram, Figure 10, shows the current configuration of this system. Racks 1A and 1B are the Primary and Hot Standby Controllers (CPU). Racks two through twelve are spread out through the facility as remote I/O racks controlling their designated descriptions. Redundant fiber optics cables provide reliable means of communications to these racks. In addition, multiple human machine interfaces (HMI) provide redundancy for operations to run the facility.

It is important to note that the FGD control system plays a key role for overall availability and reliability of the Cokenergy plant. If the control system would fault on both PLC controllers, all FGD controls would be inoperative, including both ID fans. If the ID fans are not maintaining draft through the flue gas system, then flue gas is not pulled through the HRSGs or through the FGD system. Without flue gas, all HRSGs are offline, with IHCC stack lids opening automatically to maintain natural draft to the ovens. Because of this requirement maintenance of the Modicon PLC system has high importance.

Cokenergy will follow the Modicon OEM recommended preventative maintenance tasks for the FGD PLC control system listed below:

- Maintenance of daily operating system back-ups for the PLC controllers, in the event one unit experiences a fault and must be reloaded;
- Firmware upgrades, as available and provided by the OEM;
- Programming software updates, as available and provided by the OEM;
- PLC processor memory optimization, periodically per OEM recommendations.

The first three of these preventative maintenance activities can be completed with the redundant PLC system on-line, working between the primary and secondary PLC controllers. This allows the PLC to be updated with operational system updates as the OEM identifies and develops revisions. Cokenergy follows these guidelines to ensure system reliability.

The final maintenance recommendation requires that both primary and secondary PLC controllers be taken offline for the optimization process. The OEM recommends this optimization after significant software, programing, and/or hardware upgrades are completed on the Modicon. Because of on-going system improvements to both hardware and automation programing, Cokenergy anticipates the need to complete an optimization process approximately every two years. This requirement will continue to be evaluated in coordination with the OEM, due to its implications on venting and SO_2 compliance, and the PMO Plan will be updated as needed to reflect changes in the optimization process.

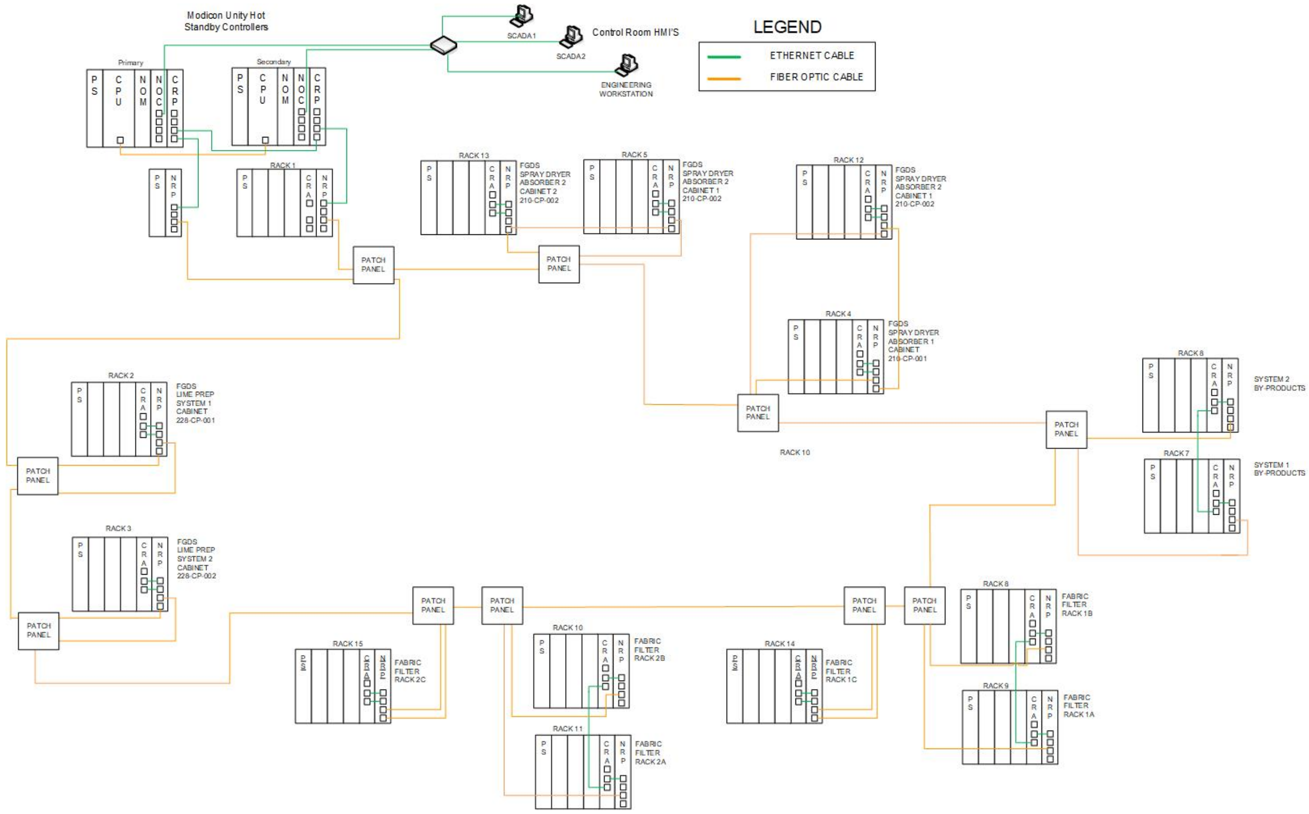


Figure 10 – Schematic of FGD Modicon Control System Configuration

6.0 Continuous Emissions Monitoring System (CEMs)

Pursuant to Section D.1.9 of Cokenergy's Title V permit, the concentrations of SO_2 and O_2 must be monitored from the stack and the SO_2 emission rate from the main stack. Cokenergy must provide the output from the CEMS to IHCC for utilization in the emission tracking system. Opacity monitoring is required in accordance with Section D.1.10 of the permit. In accordance with paragraph 19 of the CD, Cokenergy has installed a permanent flow monitor to measure the volumetric flow rate of the main stack.

The CEMS is an integrated system manufactured by Monitoring Solutions, Inc. Figure 11 presents a simplified illustration of CEMS equipment installed on the stack. The equipment configuration in the CEMS equipment shelter is included in Attachment 3.

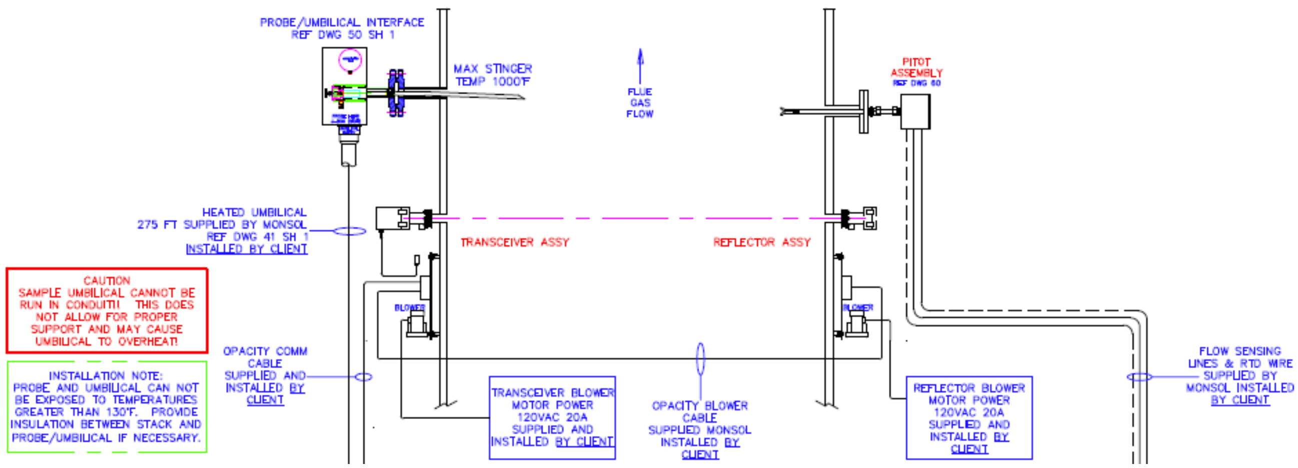


Figure 11 - CEMS Stack Layout

Flue gas is extracted from the stack and is protected by maintaining the flue gas temperature as it is being transported. It is also necessary to prohibit the flue gas sample from coming into contact with any material that could alter the concentration of the sample until conditioning is complete. A heat trace installed in the umbilical, regulated by a rack mounted temperature controller, keeps the sample gas at a desired temperature above 220ºF. The stack gas first comes in contact with a cell to measure the oxygen (O_2) concentration on a wet basis prior to entering the Sample Gas Conditioner.

As the extracted gas enters the Sample Gas Conditioner it is cooled by a thermoelectric cooler (to remove moisture) with a temperature set point of +4ºC, run through a particulate filter to remove any other sample contaminates and delivered to the gas control panel. Rotometers control and monitor the sample flow rate of dry gas to the SO_2 and O_2 analyzer. A gauge is provided to monitor sample pressure. Each analyzer draws the required amount of sample from the sample manifold. The gas control panel also controls the flow of excess sample to the sample vent.

COMS (Continuous Opacity Monitoring System) - monitors the opacity of particulate flowing through a stack or duct. The system measures opacity as a percentage of light passing through the gases compared to the reference light beam originating from source. It consists of four major components: the Transmissometer, the terminal control box, the air-purging system and the remote-control unit and data acquisition equipment. The Transmissometer component consists of an optical transmitter/receiver (transceiver) unit mounted on one side of a stack or duct and a retro reflector unit mounted on the opposite side. The transceiver unit contains the light source, the photodiode detector, and the associated electronics. The transceiver uses a single-lamp, single detector system to determine opacity. An LED light source is modulated electronically at 2 KHz to eliminate any ambient light interference. The modulated beam is configured to alternately produce reference and measurement signals so that the effects of variations in the optical and electronic components of the opacity monitor are minimized.

The display terminal control box mounted beside the transceiver unit provides on-stack readout of the opacity output from the transceiver and can be used as a diagnostic tool.

The air purging system serves a threefold purpose: 1) it provides an air window to keep exposed optical surfaces clean; 2) it protects the optical surfaces from condensation of stack gas moisture; and 3) it minimizes thermal conduction from the stack to the instrument. A standard installation has one air-purging system for each of the transceiver and the retro reflector units. The remote-control unit communicates with the remote display unit via an RS 422 cable.

CEMFlow – A simple S-type pitot tube is utilized to measure differential pressure as gas flows up the stack. High and low pressure is measured, then utilized to calculate stack velocity (using the Bernoulli equation). Multiplying by the stack diameter converts this velocity to flow. The stack gas temperature is also monitored using a standard thermocouple.

CEMCON (Continuous Emission Monitoring Controller System) - receives and stores data generated by the CEMS and automatically controls CEMS operations such as system purge, sample air flow, calibration, and detection of alarm conditions. In addition, it provides the communication link between CEMS and CEMDAS. The CEMCON system consists of a PLC controller with power supply and a multifunction keypad for operator interface.

CEMDAS (Continuous Emission Monitoring Data Acquisition System) - retrieves the data stored by the CEMCON and performs the required calculations to determine if the readings are within required limits. The system is designed to provide alarm messages and signals in the event the results do not meet applicable requirements. CEMDAS can also generate the required reports used in EPA audits and in evaluating system operability.

The emissions monitoring equipment surveillance and maintenance requirements are included in the site QA/QC plan.

Emissions Tracking System (ETS)
In order to calculate SO_2 emissions from the Indiana Harbor Coke Company (IHCC) emergency vent stacks and calculate the combined SO_2 emissions from IHCC and Cokenergy, IHCC utilizes ETS. The ETS system utilizes coke production data, HRSG steam production, vent lid status, and coal analytical data to calculate the potential SO_2 emissions from venting using a material balance. Cokenergy provides actual sulfur dioxide data from the stack CEMS to allow for the calculation of site SO_2 emissions

With the addition of the flow monitor on the Cokenergy stack (201), the IHCC ETS system is in the process of being updated pursuant to paragraph 21 of the CD. Once complete the SO_2 emission will be calculated using the actual stack flow rate.

7.0 Emissions Minimization Efforts with IHCC

Because of the close dependence between the two plants, there is a need for daily communication between the two plants at multiple levels so that maintenance activities can be coordinated, and forced outage events can be more efficiently and quickly resolved. Cokenergy will make every effort to coordinate with IHCC and conduct required maintenance during scheduled bypass venting events.

In the event of bypass venting in excess of the daily venting limit of 19%, Cokenergy, working in conjunction with IHCC, will minimize emissions to the extent practical as set forth in paragraph 17 of the Consent Decree.

8.0 Electrical Conditions and Responses to Electrical Distribution Failures at AM

The AM Indiana Harbor integrated steel facility, the IHCC metallurgical coke plant, and Cokenergy form an interconnected electrical distribution system. This is important to note for this plan because changes to the electrical conditions outside of Cokenergy can impact the operation and availability of Cokenergy's equipment.

Cokenergy is interconnected with the AM Indiana Harbor electrical distribution grid by two 69kV transmission lines – 2RX04 and 2RS03. These supply redundant power to the Cokenergy facility, and are each stepped down to 13.8kV to supply the full Cokenergy facility equipment on two 13.8kV bus lines. If one of these 69kV lines is down, the internal tie breaker between the two bus lines can be closed to power both sides of the bus, maintaining power to the entire Cokenergy plant. Power generated by Cokenergy's steam turbine generator similarly is stepped up from 13.8kV to 69kV and is supplied to the AM Indiana Harbor grid by 2RS03.

If both of the 69kV bus line are down, due to issues with the AM Indiana Harbor electrical grid, then the Cokenergy facility will be without operating power and all equipment will be offline. Because power to IHCC is supplied through the Cokenergy 4160V bus lines to IHCC, this will also mean that IHCC is also without operating power.

It is important to note that the Cokenergy facility is not configured electrically to operate as an independent electrical "island" within the AM Indiana Harbor electrical grid. This means that even if all Cokenergy equipment and systems are in operational order, if electrical supply from the AM Indiana Harbor grid fails, Cokenergy facility will be offline until power can be restored to at least one of the 69kV bus lines.

This failure in electrical distribution has occurred a limited number of times in recent years due either to (1) lightning strikes on key AM electrical grid components, or (2) equipment failure on key AM electrical grid components – typically transformers.

Under these circumstances, Cokenergy will follow these standard protocols:

(1) Cokenergy management remains in regular communication with AM Utilities counterparts to best coordinate return-to-service activities;
(2) Cokenergy management remains in regular communication with IHCC counterparts to best coordinate return-to-service activities;
(3) Cokenergy staff prepares all equipment, and if necessary makes required repairs, to allow best possible return-to-service time, with emphasis on environmental control systems;
(4) For long duration events, Cokenergy will discuss and coordinate emissions minimization efforts with IHCC.

9.0 PMO Plan Management and Revisions

Per the Consent Decree, Cokenergy and IHCC have agreed to implement a Compliance Assurance Plan (CAP) in the PMO Plans to address potential periods of higher production levels. IHCC is responsible for monthly evaluation of production and sulfur content of dry coal to identify when they exceed both of the levels indicated in the following chart in two consecutive months.

"High Production Level Months"

Average Monthly Sulfur Content of Dry Coal	Between 0.7% and 0.9%	>0.9%
Average Monthly Tons of Dry Coal Charged	144,000	128,000

IHCC and Cokenergy will jointly evaluate whether subsequent High Production Level Months could cause exceedances of PM or SO_2 limits in the Companies' Permits and the Consent Decree, and if so, the steps that will be taken to prevent those exceedances. Cokenergy is responsible for evaluating the CAP actions related to operability and control of the FGD and HRSG equipment. The CAP is required to be submitted once prepared or updated and for any instance when the CAP had to be implemented to ensure compliance with PM or SO_2 limits.

Any update to the PMO Plan or failure to follow guidelines identified in the PMO Plan will be reported to USEPA and IDEM in a semi-annual progress report.

PMO PLAN REVISION HISTORY

Revision #	Date	Description of Change	Approved By
0	6/28/2018	Initial plan development	D. Pack
1	11/18/2018	Incorporate governments comments	L. Ford
2	12/13/2018	Incorporate final comments from USEPA and IDEM	L. Ford
3	02/26/2019	Correct minor errors in tube wall thickness table in Section 4.5 and SDA Inspection Table 4.	L. Ford

Attachment 1 – HRSG Cleaning Procedure

Primary Energy COKENERGY LLC	Document: CE-SOP-300-020	
	HRSG Cleaning	
OPS Document	Issue Date: 06/27/2018	Page 1 of 2

1. Purpose

This HRSG cleaning procedure was created in order to provide clear guidelines and steps to follow when cleaning a HRSG.

2. Scope

This procedure applies to the Cokenergy facility operated by Primary Energy, its employees, as well as independent contractor personnel and visitors.

3. Procedure

3.1 Pre-cleaning setup

3.1.1 Load tanker truck with condensate from pump house or water from the HRSG wash facility tank if filtered wash water is available. See *CE-EHS-833-A05-00 Load Truck with Filtered Wash Water* for details on how to load the tanker truck with filtered wash water.

3.1.2 The pH of the water should be adjusted using soda ash. The target concentration of the soda ash solution is 7%, which is achieved by combining eleven (11) 50-pound bags of soda ash with 950 gallons of water. Once the soda ash is mixed in the truck the pH should be verified to be in the range of 11-12.

3.2 Boiler Cleaning

3.2.1 Verify boiler has been locked out and opened, and that Cokenergy Management has completed an "as-is" internal inspection. Obtain approval from Cokenergy Management to begin the cleaning.

3.2.2 All boiler doors should be in place on the boiler other than the boiler door that will be entered. This is to prevent any water from leaking out the other doors during the wash.

3.2.3 Install a vacuum hose in the door that will be entered to vacuum out the water as the boiler is being washed.

3.2.4 The amount of water in gallons taken out to the boiler for the wash is to be documented.

3.2.5 Wash the boiler with high pressure, per cleaning contractor's procedures, using the soda ash mixture.

3.2.6 Randomly check the pH of the wash water during the wash to verify the pH is between 6 and 9.

3.2.7 The waste water vacuumed from the boiler should be checked for pH before returning the water to the Boiler Wash RCRA Facility. The truck operator should adjust the pH with additions of Soda Ash until the water is brought to neutral within pH range of 6

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	HRSG Cleaning	
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and 9.

3.2.8 Once pH is verified in accordance with 3.2.7 above, transfer the waste boiler wash water to the Boiler Wash RCRA Facility. Unload the waste wash water at the facility in accordance with EHS Procedure *CE-EHS-833-A01-00 Boiler Wash RCRA Facility-Appendix 1 Unload Truck to Hazardous Waste Dewatering Box.*

3.2.9 Prior to final rinse, the HRSG Area Manager or designate will complete an inspection of clean condition to verify the wash is complete.

3.2.10 Final rinse of the entire boiler and economizer with pure water is done once the initial wash is completed and inspected by Cokenergy Management.

3.2.11 Once the boiler wash has been completed and all the waste water has been transferred to the Boiler Wash RCRA Facility, the amount of the waste wash water returned to the facility is to be documented. This is to determine how much of the water that was used for the boiler cleaning has been recovered.

4. Implementation

4.1 This procedure is effective upon the issuance date and upon any subsequent revisions.

5. Exceptions and Variances

5.1 Any variances to this Standard must be authorized by the General Manager. Designates may be appointed to cover during absences. This approval may be electronic or in hard copy form.

6. Document Control

REVISION HISTORY

Revision #	Date	Description of Change	Written by	Approved By
01	06/27/2018	Approve Final Revisions	R. Wranosky	K. Kaufman

Distribution

Electronic Copies	S: Job Procedures\HRSGS\ R: Latest Procedures
Paper Copies	none

Document Responsibility

Owner	R. Wranosky

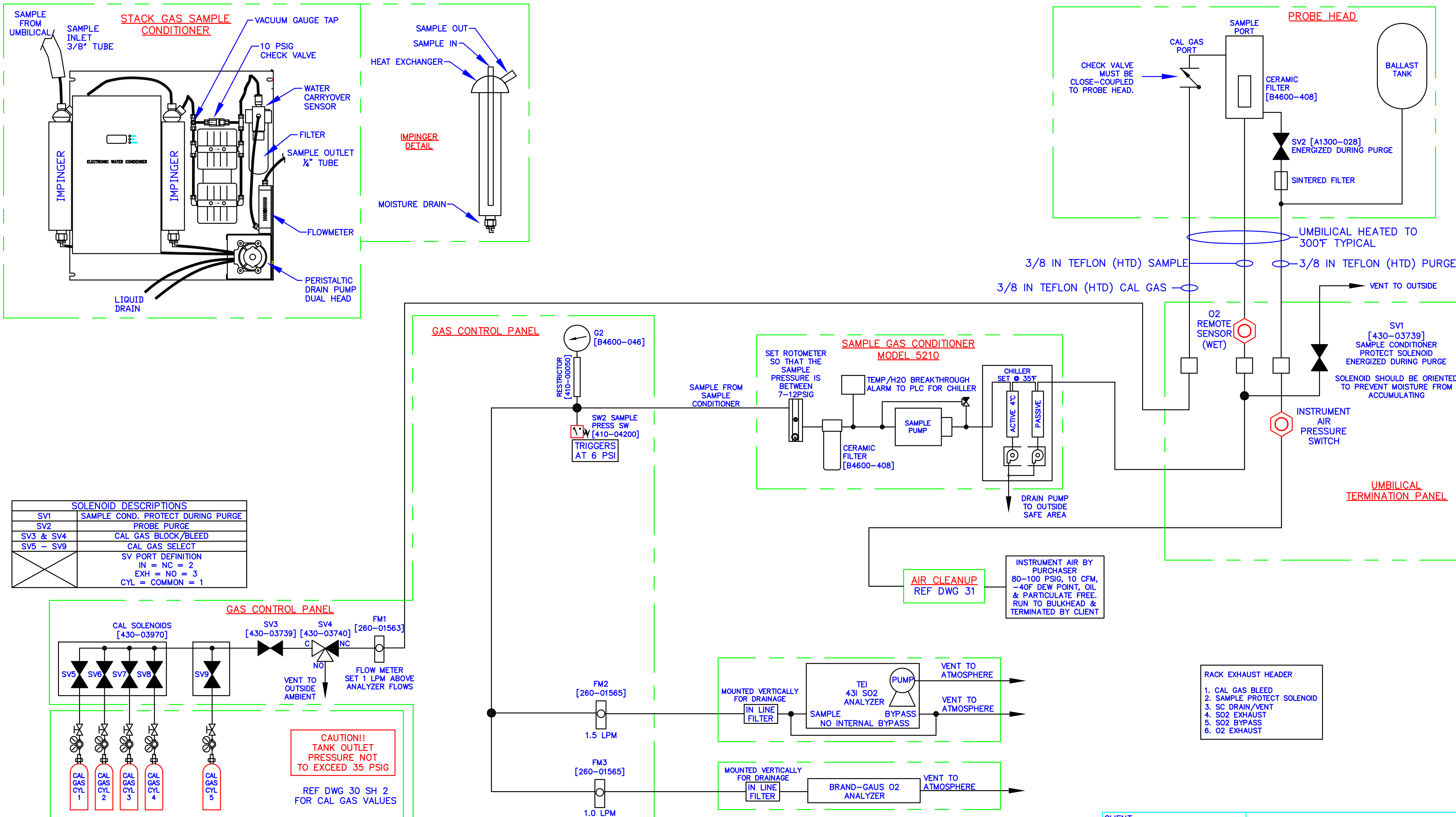
Attachment 2 – Example HRSG Maintenance Outage Work Orders

Example of standard package of maintenance Work Orders (WO) for annual HRSG outage, for HRSG D4.

WO list is exported in MSExcel format from Maximo

HRSG Complete Offline Task Packet		HRSG D4		
PM	**Description**	**Asset**	**Location**	**Status**
1086	D4 Boiler Cleaning	300-CL-D4	HRSG D4	ACTIVE
1149	Boiler Main Power Transformer Cleaning - D4		HRSG D4	ACTIVE
15 DLAD4	Drum Level A Calibration - D4	300-IN-D4	HRSG D4	ACTIVE
15 DLBD4	Drum Level B Calibration - D4	300-IN-D4	HRSG D4	ACTIVE
15 EIPD4	Economizer Inlet Pressure Calibration - D4	300-IN-D4	HRSG D4	ACTIVE
15 EOPD4	Economizer Outlet Pressure Calibration - D4	300-IN-D4	HRSG D4	ACTIVE
15 FCVD4	Boiler Feedwater Control Valve Calibration - D4	300-IN-D4	HRSG D4	ACTIVE
15 FGDD4	Flue Gas Damper Calibration - D4	300-IN-D4	HRSG D4	ACTIVE
15 FIGD4	Flue Gas Iso Guillotine Damper Calibration - D4	300-IN-D4	HRSG D4	ACTIVE
15 FWFD4	Boiler Feed Water Flow Calibration - D4	300-IN-D4	HRSG D4	ACTIVE
15 FWMD4	Feed Water Isolation MOV - D4	300-IN-D4	HRSG D4	ACTIVE
15 INPD4	Boiler Inlet Pressure Calibration - D4	300-IN-D4	HRSG D4	ACTIVE
15 SDPD4	Steam Drum Pressure Calibration - D4	300-IN-D4	HRSG D4	ACTIVE
15 SVVD4	Start-up Vent Valve Calibration - D4	300-IN-D4	HRSG D4	ACTIVE
15-GR-D4	BLR Main Steam Block Valve Lubrication, 1Y	300	HRSG D4	ACTIVE
15-IN-D4	Inspection of D4 boiler	300-BR-D4	HRSG D4	ACTIVE
15DUCTD4	Louver and Casing Repairs D4 boiler cleaning	300-DU-D4	HRSG D4	ACTIVE
15FNTSD4	Boiler Functional Test - D4	300-IN-D4	HRSG D4	ACTIVE
15GUID4	Boiler Guillotine damper PM D4	300	HRSG D4	ACTIVE
15INSD4	Inspection Support and Prep for D4	300-MM-D4	HRSG D4	ACTIVE
15INSPD4	Boiler Cleaning and Inspection Checklist - D4	300-D4	HRSG D4	ACTIVE
15MOV-D4	Feedwater MOV Greasing PM	300-VA-D4E	HRSG D4	ACTIVE
15PFNTD4	Boiler Pre-Start Functional Test - D4	300-IN-D4	HRSG D4	ACTIVE
15REFD4	Refractory work during boiler outage D4	300-DU-D1	HRSG D4	ACTIVE
15SUPD4	Inspect any bad superheater shields D4	300-BR-D4	HRSG D4	ACTIVE
15VLV-D4	D4 Boiler Valve PM	300-PI-D4	HRSG D4	ACTIVE

Attachment 3 – CEMS Shelter Layout



SOLENOID DESCRIPTIONS	
SV1	SAMPLE COND. PROTECT DURING PURGE
SV2	PROBE PURGE
SV3 & SV4	CAL GAS BLOCK/BLEED
SV5 – SV9	CAL GAS SELECT
	SV PORT DEFINITION IN = NC = 2 EXH = NO = 3 CYL = COMMON = 1

RACK EXHAUST HEADER
1. CAL GAS BLEED
2. SAMPLE PROTECT SOLENOID
3. SC DRAIN/VENT
4. SO2 EXHAUST
5. SO2 BYPASS
6. O2 EXHAUST

REV	DATE	BY	CKD	APD	REVISION DESCRIPTION
B	06/30/15	TAB	EJM	TAB	CORRECTED ANALYZER MODEL NUMBER
A	06/11/15	TAB	EJM	TAB	INITIAL RELEASE

CLIENT:
PRIMARY ENERGY
EAST CHICAGO, IN
STACK 201

MONITORING SOLUTIONS
4440 S. HIGH SCHOOL RD. * SUITE D * INDPLS, IN 46241 * 317-856-9400 * FAX: 317-856-9410
78 ROUTE 173 * SUITE 7 * HAMPTON, NJ 08827 * 908-713-0172 * FAX: 908-713-0221

	DATE	INT.
DRAWN	06/11/15	TAB
DESIGN	06/11/15	TAB
CHECKED	06/11/15	EJM
APPRD	06/11/15	TAB
SCALE	NONE	

SAMPLE FLOW OVERVIEW

FULL EXTRACTIVE

MONITORING SOLUTIONS P.A. NO.	CAD FILE NO.	DRAWING NO.	SHEET	REV
5590	5590302	30	2 OF 3	B