

**MI-ROP-B4942**  
**Renewable Operating Permit (ROP)**  
**Compliance Test Report**

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**Dow AgroSciences, LLC**  
**Harbor Beach, Michigan**

**Sampling Date(s):**

**May 25<sup>th</sup>, 2016**

**May 26<sup>th</sup>, 2016**

**May 31<sup>st</sup>, 2016**

**June 1<sup>st</sup>, 2016**

**June 2<sup>nd</sup>, 2016**

## Executive Summary

This report presents performance test results for Title V Renewable Operating Permit compliance testing in May/June 2016. This testing is required at least once during the term of the ROP but not later than five years from the date of the previous performance test. The ROP requires compliance verification of nitrogen oxides (NOx) and carbon monoxide (CO) concentrations and emission rates defined in FG-UTILITIES. There are four operating modes that are explained in detail later in this document. The Supplemental Mode is the operating mode with the greatest emission potential. This is the operating mode regulated by FG-UTILITIES.

In addition to testing in Supplemental Mode, DAS also tested Fresh Air and Turbine/TEG Modes. The Supplemental and Turbine/TEG Modes were tested with the SoLoNOx™ burner technology on and again with it off on both the North and South Units.

Results will be used to demonstrate compliance with the current ROP. The data will be used to support a permit application to define operating conditions associated with SoLoNOx operations. The emission results will also be used to establish emission factors to support MAERS.

Fresh Air Mode – EU_N_Burner								
Run	Natural Gas (MMSCF/Hr)	Stack Flow (DSCFHR)	NOx (ppm)	NOx (lb/hr)	NOx Nat Gas Factor (lb/mmSCF)	CO (ppm)	CO (lb/hr)	CO Nat Gas Factor (lb/mmSCF)
1	0.03216	1.93E+06	18.8	4.33	134.58	32.7	4.58	142.51
2	0.03216	1.90E+06	18.8	4.28	132.93	32.8	4.54	141.20
3	0.03222	1.91E+06	18.9	4.31	133.89	32.8	4.56	141.43
Average	0.03218	1.91E+06	18.8	4.31	133.80	32.8	4.56	141.71

Fresh Air Mode – EU_S_Burner								
Run	Natural Gas (MMSCF/Hr)	Stack Flow (DSCFHR)	NOx (ppm)	NOx (lb/hr)	NOx Nat Gas Factor (lb/mmSCF)	CO (ppm)	CO (lb/hr)	CO Nat Gas Factor (lb/mmSCF)
1	0.03162	1.89E+06	19.6	4.42	139.82	16.3	2.24	70.78
2	0.03180	1.86E+06	18.8	4.18	131.45	16.7	2.26	71.07
3	0.03180	1.89E+06	18.0	4.06	127.58	17.3	2.37	74.65
Average	0.03174	1.88E+06	18.8	4.22	132.95	16.8	2.29	72.17

TEG/Turbine – EU_N_Turbine SoLoNOx On								
Run	Natural Gas (MMSCF/Hr)	Stack Flow (DSCFHR)	NOx (ppm)	NOx (lb/hr)	NOx Nat Gas Factor (lb/mmSCF)	CO (ppm)	CO (lb/hr)	CO Nat Gas Factor (lb/mmSCF)
1	0.04068	1.89E+06	17.8	4.01	98.55	2.6	0.36	8.75
2	0.04008	1.91E+06	17.5	3.99	99.58	2.7	0.38	9.36
3	0.04044	1.92E+06	17.8	4.07	100.74	2.8	0.39	9.64
Average	0.04040	1.90E+06	17.7	4.02	99.62	2.7	0.37	9.25

TEG/Turbine – EU_S_Turbine SoLoNOx On								
Run	Natural Gas (MMSCF/Hr)	Stack Flow (DSCFHR)	NOx (ppm)	NOx (lb/hr)	NOx Nat Gas Factor (lb/mmSCF)	CO (ppm)	CO (lb/hr)	CO Nat Gas Factor (lb/mmSCF)
1	0.03654	1.87E+06	15.9	3.55	97.24	3.7	0.50	13.77
2	0.03636	1.87E+06	15.6	3.48	95.74	3.8	0.52	14.19
3	0.03678	1.89E+06	16.0	3.62	98.29	4.0	0.55	14.95
Average	0.03656	1.88E+06	15.8	3.55	97.09	3.8	0.52	14.30

<b>TEG/Turbine – EU N Turbine SoLoNOx Off</b>								
Run	Natural Gas (MMSCF)	Stack Flow (DSCFHR)	NOx (ppm)	NOx (lb/hr)	NOx Nat Gas Factor (lb/mmSCF)	CO (ppm)	CO (lb/hr)	CO Nat Gas Factor (lb/mmSCF)
1	0.04062	1.89E+06	44.9	10.16	250.12	67.2	9.26	227.89
2	0.04020	1.90E+06	44.3	10.06	250.17	67.9	9.39	233.46
3	0.03912	1.87E+06	42.9	9.59	245.09	71.0	9.66	246.93
Average	0.03998	1.89E+06	44.0	9.94	248.46	68.7	9.43	236.09

<b>TEG/Turbine – EU S Turbine SoLoNOx Off</b>								
Run	Natural Gas (MMSCF)	Stack Flow (DSCFHR)	NOx (ppm)	NOx (lb/hr)	NOx Nat Gas Factor (lb/mmSCF)	CO (ppm)	CO (lb/hr)	CO Nat Gas Factor (lb/mmSCF)
1	0.03810	1.88E+06	41.7	9.35	245.38	123.2	16.82	441.34
2	0.03816	1.88E+06	41.5	9.33	244.42	124.9	17.09	447.85
3	0.03798	1.88E+06	41.4	9.30	244.84	122.9	16.81	442.47
Average	0.03808	1.88E+06	41.5	9.33	244.88	123.7	16.90	443.89

<b>Supplemental Mode – EU N Burner &amp; EU N Turbine SoLoNOx Off</b>								
Run	Natural Gas (MMSCF)	Stack Flow (DSCFHR)	NOx (ppm)	NOx (lb/hr)	NOx Nat Gas Factor (lb/mmSCF)	CO (ppm)	CO (lb/hr)	CO Nat Gas Factor (lb/mmSCF)
1	0.07146	1.85E+06	58.3	12.90	180.55	69.8	9.40	131.60
2	0.07182	1.83E+06	59.2	12.95	180.28	67.2	8.95	124.58
3	0.07164	1.84E+06	59.6	13.08	182.64	65.3	8.73	121.82
Average	0.07164	1.84E+06	59.0	12.98	181.16	67.4	9.03	126.00

<b>Supplemental Mode – EU S Burner &amp; EU S Turbine SoLoNOx Off</b>								
Run	Natural Gas (MMSCF)	Stack Flow (DSCFHR)	NOx (ppm)	NOx (lb/hr)	NOx Nat Gas Factor (lb/mmSCF)	CO (ppm)	CO (lb/hr)	CO Nat Gas Factor (lb/mmSCF)
1	0.06948	1.82E+06	56.8	12.35	177.79	56.2	7.44	107.10
2	0.06954	1.81E+06	56.1	12.09	173.91	58.5	7.68	110.49
3	0.06942	1.83E+06	56.3	12.27	176.75	58.0	7.70	110.86
Average	0.06948	1.82E+06	56.4	12.24	176.15	57.6	7.60	109.45

<b>Supplemental Mode – EU N Burner &amp; EU N Turbine SoLoNOx On</b>								
Run	Natural Gas (MMSCF)	Stack Flow (DSCFHR)	NOx (ppm)	NOx (lb/hr)	NOx Nat Gas Factor (lb/mmSCF)	CO (ppm)	CO (lb/hr)	CO Nat Gas Factor (lb/mmSCF)
1	0.07344	1.82E+06	31.6	6.88	93.70	57.1	7.57	103.06
2	0.07326	1.80E+06	31.2	6.72	91.78	57.6	7.56	103.15
3	0.07344	1.84E+06	30.8	6.78	92.35	60.0	8.04	109.52
Average	0.07338	1.82E+06	31.2	6.80	92.61	58.2	7.72	105.24

<b>Supplemental Mode – EU S Burner &amp; EU S Turbine SoLoNOx On</b>								
Run	Natural Gas (MMSCF)	Stack Flow (DSCFHR)	NOx (ppm)	NOx (lb/hr)	NOx Nat Gas Factor (lb/mmSCF)	CO (ppm)	CO (lb/hr)	CO Nat Gas Factor (lb/mmSCF)
1	0.06912	1.84E+06	30.5	6.70	96.93	12.4	1.66	23.99
2	0.06888	1.84E+06	31.3	6.87	99.72	11.6	1.55	22.50
3	0.06834	1.86E+06	32.1	7.12	104.14	10.5	1.42	20.73
Average	0.06878	1.84E+06	31.3	6.90	100.27	11.5	1.54	22.41

The following are the plant and sampling contacts for questions about the information in this sample report:

Primary Dow Contact	Dow Sampling Resource
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## Introduction

### Description of Industrial and Unit Process -

DAS operates a pesticide active ingredient manufacturing facility in Harbor Beach, Michigan. Operations include two heat recovery steam generators (HRSG) identified as the north and south duct burners. For the purpose of this test plan and any associated communications, the terms HRSG and duct burners are interchangeable. Both burners are fired with natural gas. The emission units are identified as EU\_N\_BURNER and EU\_S\_BURNER. Together these units make up flexible group FG-BURNERS.

Operations also include two gas fired turbines. These are commonly identified as the north and south natural gas fired turbine engines. The emission units are identified as EU\_N\_TURBINE and EU\_S\_TURBINE. Together these units make up flexible group FG-TURBINES.

### Type and Quantity of Raw and Finished Materials used in Process

These HRSG and turbine assets only burn natural gas.

### Description of cyclical or batch operations that impact emission profiles:

These units operate continuously. The emission profile (formation of NO<sub>x</sub> and CO) is a function of the natural gas feed rate under normal operating conditions.

### Operating Parameter Requirement

The facility uses a process control computer to automatically control the process within specific ranges dictated by process limits. Operating ranges are variable and dictated by production demand. Process parameters are monitored for automatic or semi-automatic action. Parameters include, but are not limited to temperatures, pressures and flow rates. This process unit is not required to incorporate any monitoring data collection such as continuous emission monitoring systems (CEMS) into unit operations.

### Process Rate

The table below summarizes process operating rates. Following the table is a description of the four operating modes.

<b>Table 1.1 – Normal Processing Rate Summary</b>	
<b>Process Unit</b>	<b>Typical Operating Rates</b>
FG-TURBINES, NORTH (Supplemental, TEG or Turbine Modes)	~ 30 to 40 Million BTU/hr
FG-TURBINES, SOUTH (Supplemental, TEG or Turbine Modes)	~ 30 to 40 Million BTU/hr
FG-BURNERS, NORTH (Supplemental Mode)	~ 5 to 20 Million BTU/hr
FG-BURNERS, NORTH (Fresh Air Mode)	~ 20 to 25 Million BTU/hr
FG-BURNERS, SOUTH (Supplemental Mode)	~ 5 to 20 Million BTU/hr
FG-BURNERS, SOUTH (Fresh Air Mode)	~ 10 to 25 Million BTU/hr

FG-TURBINES & FG-BURNERS comprise Flexible Group FG-UTILITES and can operate in four different operating modes. These modes are identified as Supplemental, Turbine Exhaust Gas, Fresh Air, and Turbine Modes:

- Supplemental Mode = gas turbine operating, heat recovery steam generator operating. Emissions for the north unit vent through SV00007 & the south unit through SV00009.
- Turbine Exhaust Gas (TEG) Mode = gas turbine operating & heat recovery steam generator operating (the burner is not operating). Emissions for the north unit vent through SV00007 & the south unit through SV00009.
- Fresh Air Mode = burner operating & heat recovery steam generator operating (the gas turbine is not operating). Emissions for the north unit vent through SV00007 & the south unit through SV00009.
- Turbine Mode (Air Generation) = gas turbine operating (the burners & heat recovery steam generator are not operating). Emissions for the north unit vent through SV00008 & the south unit through SV00010.

Greater than 95% of the operating time these assets are operated in either Supplemental or Turbine Exhaust Gas Modes. The Fresh Air and Turbine Modes only occur when one of the associated assets are down for maintenance.

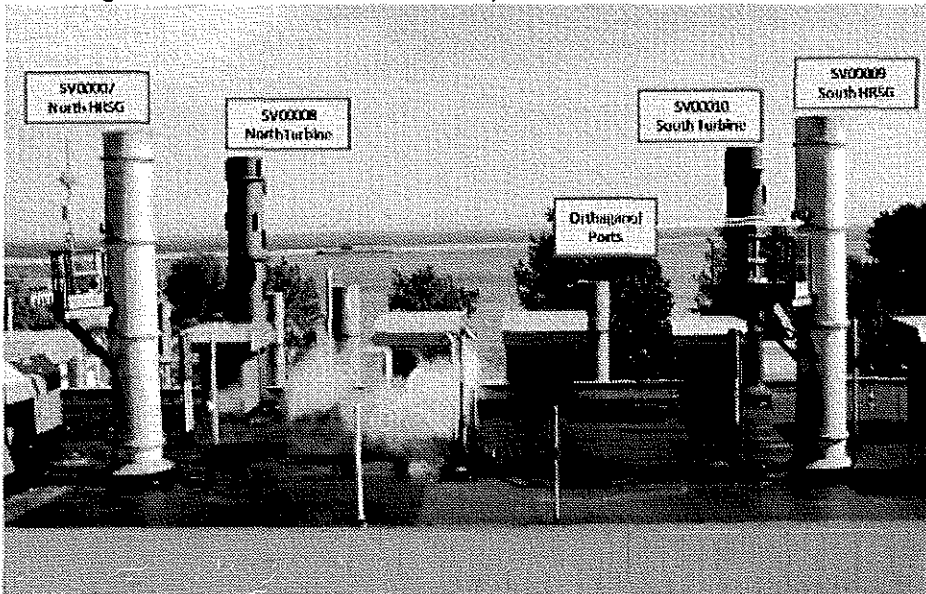
The Turbine Exhaust Gas (TEG) Mode and Turbine Mode potential to emit are identical.

### Description of Air Pollution Control Equipment

Both turbines are equipped with SoLoNOx™ technology. SoLoNOx™ is a low emissions option. SoLoNOx uses lean-premixed combustion technology to ensure uniform air/fuel mixture and to prevent formation of regulated pollutants such as NOx.

### Sampling Conditions and Runs

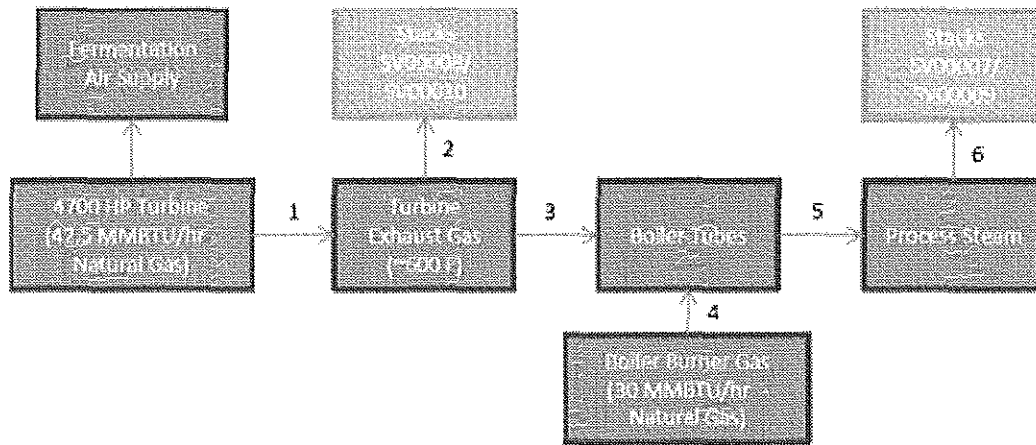
The image below shows the four atmospheric vents associated with the turbine and HRGS assets.



The table below summarizes the number and length of sampling runs which will constitute a complete test. The normal worst case emission profile occurs during Supplemental Mode because both the turbine and boiler are combusting natural gas and generating combusting by products (CO and NOx) with the SoLoNOx™ burner technology operational. The absolute worst case condition occurs when in Supplemental Mode and the SoLoNOx™ burner technology off-line which is not a normal operating condition. The SoLoNOx™ burner technology is only off-line for extended periods during sub-zero ambient conditions.

<b>Test Condition Summary</b>				
<b>Process Units</b>	<b>Stack</b>	<b>Runs</b>	<b>Mode</b>	<b>Operating Rates</b>
EU_N_Burner	SV00007	3	Fresh Air	Burner $\cong$ 32 MMBTU/Hr
EU_S_Burner	SV00009	3	Fresh Air	Burner $\cong$ 32 MMBTU/Hr
EU_N_Burner EU_N_Turbine	SV00007	3	Supplemental Mode (SoLoNOx™ - Off)	Burner $\cong$ 31 MMBTU/Hr Turbine $\cong$ 40 MMBTU/Hr Total $\cong$ 71 MMBTU/Hr
EU_S_Burner EU_S_Turbine	SV00009	3	Supplemental Mode (SoLoNOx™ - Off)	Burner $\cong$ 32 MMBTU/Hr Turbine $\cong$ 38 MMBTU/Hr Total $\cong$ 69 MMBTU/Hr
EU_N_Burner EU_N_Turbine	SV00007	3	Supplemental Mode (SoLoNOx™ - On)	Burner $\cong$ 32 MMBTU/Hr Turbine $\cong$ 41 MMBTU/Hr Total $\cong$ 73 MMBTU/Hr
EU_S_Burner EU_S_Turbine	SV00009	3	Supplemental Mode (SoLoNOx™ - On)	Burner $\cong$ 32 MMBTU/Hr Turbine $\cong$ 37 MMBTU/Hr Total $\cong$ 69 MMBTU/Hr
EU_N_Turbine	SV00007	3	TEG Mode (SoLoNOx™ - Off)	Turbine $\cong$ 40 MMBTU/Hr
EU_S_Turbine	SV00009	3	TEG Mode (SoLoNOx™ - Off)	Turbine $\cong$ 36 MMBTU/Hr
EU_N_Turbine	SV00007	3	TEG Mode (SoLoNOx™ - On)	Turbine $\cong$ 40 MMBTU/Hr
EU_S_Turbine	SV00009	3	TEG Mode (SoLoNOx™ - On)	Turbine $\cong$ 38 MMBTU/Hr

## Block Flow Diagrams



**Turbine Mode** - Air production without steam production. Pt 1 is active. Pt 3 is closed. Emission vent through Pt 2 (SV00008 for North Unit and SV00010 for South Unit.) Approx 1% of operating time.

**Supplemental Mode** - Air production and steam production. Pt 1 is active. Pt 2 is closed. Pt 3 is open. Pt 4 is active. Pt 5 is open. Emission vent through Pt 6 (SV00007 for North Unit and SV00009 for South Unit.) Approx 40% - 50% of operating time.

**Turbine Exhaust Gas Mode** - Air production and steam production without the boiler burner operating. Pt 1 is active. Pt 2 is closed. Pt 3 is open. Pt 4 is closed. Pt 5 is open. Emission vent through Pt 6 (SV00007 for North Unit and SV00009 for South Unit.) Approx 40% - 50% of operating time.

**Fresh Air Mode** - Steam production without air production. Pt 1 is closed. Pt 2 is closed. Pt 3 is closed. Pt 4 is active. Pt 5 is open. Emission vent through Pt 6 (SV00007 for North Unit and SV00009 for South Unit.) Approx 1% of operating time.



## Test Results

The boiler and turbine assets are regulated by equipment type and in combination. FG-Burner regulates the natural gas fired HRSG. FG-Turbine regulates the natural gas fired turbines. FG-Facility regulates the assets in combination. Compliance testing is required under FG-Facility for the assets operated in combination. The tables below summarize the test results.

Results of Emission Sampling				
Unit	Pollutant/Test Method	Sampling Time (Minutes)	Actual Emission Rate	Allowable Emission Rate
<b>FG Burner Emission Limits (Fresh Air Mode)</b>				
EU_N_BURNER (Fresh Air Mode)	NOx EPA Method 7E	60	4.3 lb/hr <sup>A</sup>	4.5 lb/hr <sup>A</sup> 4.8 lb/hr <sup>A</sup>
	CO EPA Method 10	60	4.6 lb/hr <sup>A</sup>	
EU_S_BURNER (Fresh Air Mode)	NOx EPA Method 7E	60	4.2 lb/hr <sup>A</sup>	
	CO EPA Method 10	60	2.3 lb/hr <sup>A</sup>	
<b>FG Utilities Emission Limits (Supplemental Mode)</b>				
FG-UTILITIES, north (Supplemental Mode SoLoNOx™ - Off)	NOx EPA Method 7E	60	13.0 lb/hr	NOx 13.6 lb/hr & 59.57 tons/yr CO 14.1 lb/hr & 61.76 tons/yr
	CO EPA Method 10	60	9.03 lb/hr	
FG-UTILITIES, south (Supplemental Mode SoLoNOx™ - Off)	NOx EPA Method 7E	60	12.2 lb/hr	
	CO EPA Method 10	60	7.6 lb/hr	
FG-UTILITIES, north (Supplemental Mode SoLoNOx™ - On)	NOx EPA Method 7E	60	6.8 lb/hr	
	CO EPA Method 10	60	7.72 lb/hr	
FG-UTILITIES, south (Supplemental Mode SoLoNOx™ - On)	NOx EPA Method 7E	60	6.9 lb/hr	
	CO EPA Method 10	60	1.5 lb/hr	
<b>FG Turbine Emission Limits (Turbine Exhaust Gas (TEG) &amp; Turbine Modes)</b>				
EU_N_Turbine (TEG Mode SoLoNOx™ - Off)	NOx EPA Method 7E	60	56.9 ppmv <sup>B</sup> 9.9 lb/hr <sup>A</sup>	NOx 25 ppmv <sup>B</sup> & 3.8 lb/hr <sup>A</sup> CO 50 ppmv <sup>B</sup> & 4.65 lb/hr
	CO EPA Method 10	60	88.8 ppmv <sup>B</sup> 9.43 lb/hr	
EU_S_Turbine (TEG Mode SoLoNOx™ - Off)	NOx EPA Method 7E	60	57.9 ppmv <sup>B</sup> 9.3 lb/hr <sup>A</sup>	
	CO EPA Method 10	60	172.4 ppmv <sup>B</sup> 16.9 lb/hr	
EU_N_Turbine (TEG Mode SoLoNOx™ - On)	NOx EPA Method 7E	60	22.2 ppmv <sup>B</sup> 4.0 lb/hr <sup>A</sup>	<sup>A</sup> Emission rate limit is a based upon a calendar day averaging period  <sup>B</sup> ppmv concentration values are reported dry and corrected to 15% Oxygen
	CO EPA Method 10	60	3.4 ppmv <sup>B</sup> 0.37 lb/hr	
EU_S_Turbine (TEG Mode SoLoNOx™ - On)	NOx EPA Method 7E	60	21.4 ppmv <sup>B</sup> 3.6 lb/hr <sup>A</sup>	
	CO EPA Method 10	60	5.2 ppmv <sup>B</sup> 0.52 lb/hr	

## Sampling and Analytical Procedures

The table below lists all the pollutants and sampling trains used to collect measurements and samples during the performance test. These methods were performed according to the protocol listed in the appropriate Appendix A, 40 CFR 60 EPA Reference Test Method. Schematic diagrams can be found in the EPA Reference Test Methods.

<b>Test Matrix for Emission Sampling:</b>						
Sampling Location	No. of Runs	Sample/Type Pollutant	Sampling Organization	Sample Run Time (Min)	Reference Method	Target Reported Units Of Measure
Stack Exhaust	3/unit	Flow Rate	AECOM (formerly URS)	~ 60 Min	US EPA Method 1 through 4	acfm
Stack Exhaust	3/unit	Nitrogen Oxides (NOx)	AECOM (formerly URS)	~ 60 Min	US EPA Method 7E	ppmv
Stack Exhaust	3/unit	Carbon Monoxide (CO)	AECOM (formerly URS)	~ 60 Min	US EPA Method 10	ppmv
Stack Exhaust	3/unit	Oxygen (O <sub>2</sub> )	AECOM (formerly URS)	~ 60 Min	US EPA Method 3A	%

### Detailed Sampling and Analytical Procedures

The sampling and analytical procedure followed during the performance test was designed to demonstrate compliance with emission limits.

The performance test was conducted while the process units were in the operating step that generated the worst case emission profile. The sampling procedure includes the following steps:

1. Documenting the sample location dimensions and using the EPA Reference Method 1 Duct Dimension and Flow Disturbance Chart to determine traverse points.
2. For nitrogen oxides (EPA Method 7E), carbon monoxide (EPA Method 10) and oxygen (EPA Method 3A) sampling, one sampling train per location, per run, was continuously extracted from the stack and transported through a heat-traced sample line to a mobile analytical laboratory. The mobile analytical laboratory had a sample header that was shared by other instruments in the trailer. A minimum of 3 runs were collected. Each run was a minimum of sixty-minutes in duration.
3. The methods provided in the table below were used to collect samples for demonstration of compliance. Samples were collected by the Dow Internal Stack Testing Team.

<b>Sampling and Analytical Plan</b>			
Sampling Method	Sampling Plan	Analytical Method	Analytical Plan
Method 1	Traverse locations were determined prior to sampling.	Not applicable	Not applicable
Method 2	Velocity measurements were collected by traversing the stack.	Not applicable	Not applicable
Method 3	Carbon dioxide concentration were determined by FYRITE analysis	Method 3 – FYRITE	Samples were completed on-site.
Method 4	Samples were collected from a single center point.	Method 4 – Gravimetric	Samples were completed on-site.
Method 3A	Samples were collected from a single center point routed to a header used by analyzer system.	Method 3A – Paramagnetic	Samples were completed on-site.
Method 7E	Samples were collected from a single center used by analyzer system.	Method 7E – Chemiluminescent	Samples were completed on-site.
Method 10	Samples were collected from a single center used by analyzer system.	Method 10 - Infrared	Samples were completed on-site.

**EPA Method 1-4**

The number and location of traverse points in the stack were determined according to the procedures outlined in EPA Method 1. The flue gas velocity and volumetric flow rate were determined according to the procedure outline in 40 CFR 60, Appendix A, EPA Method 2. Velocity measurements were made using S-type pitot tubes conforming to the geometric specifications outlined in EPA Method 2. Differential pressures were measured with fluid manometers. Flue gas temperature, velocity, and volumetric flow rate data were recorded. Flue gas analysis for oxygen (3A) and carbon dioxide (3) and the calculation of flue gas molecular weight was performed in accordance with 40 CFR 60, EPA Methods 3 and 3A. The flue gas moisture content was determined in accordance with the procedures outlined in 40 CFR 60, Appendix A, EPA Method 4. The impingers were connected in series and contained reagents as described in Method 4. The impingers were contained in an ice bath in order to assure condensation of the moisture in the flue gas stream. Any moisture that was not condensed in the impingers was captured in the silica gel; therefore, all moisture was weighed and entered into moisture content calculations. The flue gas moisture content data was recorded.

**EPA Method 7E**

Emission sampling was conducted on the stack for NO<sub>x</sub>. The NO<sub>x</sub> sampling was conducted by continuously extracting sample from a single point in the centroidal area of the stack and analyzing a portion of the sample with a chemiluminescent analyzer. The sample was delivered to the analyzer via a heated probe and sample line. This prevents any condensation of water vapor and/or pollutant in the gas stream. The gas stream was then directed into a gas conditioning system where the moisture content of the stream is removed. The sample gas that exits the gas conditioning system was then routed to the chemiluminescent analyzer for analysis on a dry basis. Three runs of approximately one-hour duration each were conducted for each condition. The instrument was calibrated before and after each run using Protocol 1 standards.

**EPA Method 10**

Emission sampling was conducted on the outlet stack. The CO sampling was conducted by continuously extracting sample from a single point in the center of the stack and analyzing a portion of the sample by infrared. Three runs of approximately one-hour duration each were conducted for each condition.

## Calculation Example

### Analyzer Calibration Error Calculations

The calibration error test consisted of challenging each reference monitor at three measurement points against known calibration gas values. Calibration error is calculated using the following equation:

$$CE_{RM} = \frac{|Analyzer\ Response - Calibration\ Gas\ Value|}{Span\ of\ Analyzer} \times 100$$

#### South Fresh Air NOx Zero Calibration Error Example

$$CE_{RM} = \frac{|0.0\ ppmv - 0.0\ ppmv|}{60.5\ ppmv} \times 100 = \underline{0.0\ \%}$$

$$CE_{RM} = \frac{|31.1\ ppmv - 31.0\ ppmv|}{60.5\ ppmv} \times 100 = \underline{0.2\ \%}$$

$$CE_{RM} = \frac{|60.5\ ppmv - 60.5\ ppmv|}{60.5\ ppmv} \times 100 = \underline{0.0\ \%}$$

### System Calibration Bias Calculations

The system bias calibration test consisted of challenging the reference sample system at two measurement points against the local calibration values. Calibration bias calculations for the reference sample system are calculated using the following equation:

$$CB_{RM} = \frac{|System\ Calibration\ Response - Analyzer\ Calibration\ Response|}{Span\ of\ Analyzer} \times 100$$

#### South Fresh Air NOx Zero Initial System Bias Run #1 Example

$$CB_{RM} = \frac{|0.3\ ppmv - 0.0\ ppmv|}{60.5\ ppmv} \times 100 = \underline{0.5\ \%}$$

$$CB_{RM} = \frac{|30.4\ ppmv - 31.1\ ppmv|}{60.5\ ppmv} \times 100 = \underline{1.2\ \%}$$

### Calibration Drift Calculations

The calibration drift tests were conducted at the beginning and end of each run. Analyzer maintenance, repair or adjustment could not be completed until the system calibration response was recorded. Calibration drifts for the reference is calculated using the following equation:

$$CD_{RM} = \frac{|Final\ System\ Cal\ Response - Initial\ System\ Cal\ Response|}{Span\ of\ Analyzer} \times 100$$

#### South Fresh Air NOx Zero Calibration Drift Run #1 Example

$$CD_{RM} = \frac{|0.3\ ppmv - 0.3\ ppmv|}{60.5\ ppmv} \times 100 = \underline{0.0\ \%}$$

$$CD_{RM} = \frac{|30.4\ ppmv - 30.4\ ppmv|}{60.5\ ppmv} \times 100 = \underline{0.0\ \%}$$

### System Calibration Drift Correction

The gas concentrations are corrected for the system calibration bias. The concentrations are calculated using the following equations:

$$C_{Gas} = (\bar{C} - C_O) \left( \frac{C_{MA}}{C_M - C_O} \right)$$

- where:  $C_{Gas}$  = Effluent Concentration, dry ppm or %  
 $\bar{C}$  = Average Analyzer Concentration, ppm or %  
 $C_O$  = Average Initial and Final System Calibration Responses for Zero Gas, ppm or %  
 $C_M$  = Average Initial and Final System Calibration Responses for Upscale Calibration Gas, ppm or %  
 $C_{MA}$  = Actual Concentration of Upscale Calibration Gas, ppm or %

#### South Fresh Air NOx System Calibration Drift Correction Run #1 Example

$$C_{Gas} = (19.3\ ppmv - 0.3\ ppmv) \left( \frac{31.0\ ppmv}{30.4\ ppmv - 0.3\ ppmv} \right) = \underline{19.6\ ppmv}$$

#### South Fresh Air CO System Calibration Drift Correction Run #1 Example

$$C_{Gas} = (15.9\ ppmv - 0.6\ ppmv) \left( \frac{31.5\ ppmv}{30.1\ ppmv - 0.6\ ppmv} \right) = \underline{16.3\ ppmv}$$

#### South Fresh Air O2 System Calibration Drift Correction Run #1 Example

$$C_{Gas} = (17.0\ \% - 0.1\ \%) \left( \frac{9.9\ \%}{9.8\ \% - 0.1\ \%} \right) = \underline{17.3\ \%}$$

### Stack Gas Velocity & Volumetric Rates (EPA M2)

The velocity and volumetric flow rate of the stack gas are calculated using the following equations:

$$V_S = K_P C_P (\sqrt{\Delta p})_{AVG} \sqrt{\frac{T_S (AVG)}{P_S M_S}}$$

$$Q_W = V_S A_S (3600 \text{ sec/hr})$$

$$Q_{SW} = Q_W \left( \frac{528 \text{ }^\circ R}{T_S} \right) \left( \frac{P_S}{29.92 \text{ " Hg}} \right)$$

$$Q_{SD} = Q_{SW} (DGF)$$

- Where:  $V_S$  = Stack gas velocity (ft/sec)  
 $K_P$  = Pitot Tube Constant,  $85.49 \frac{ft}{sec} \sqrt{\frac{(lb/lb \text{ mol})(\text{" Hg})}{(\text{ }^\circ R)(\text{" H}_2\text{O})}}$   
 $C_P$  = Pitot Tube Coefficient, 0.84 (dimensionless)  
 $\Delta p$  = Velocity Head of Stack Gas, ("H<sub>2</sub>O)  
 $T_S$  = Stack Temperature (°R)  
 $P_S$  = Absolute Stack Pressure ("Hg)  
 $M_S$  = Molecular weight of stack gas, wet basis (lb/lb-mole)  
 $Q_W$  = Stack Gas Wet Volumetric Flow at Stack Conditions (ft<sup>3</sup>/hr)  
 $Q_{SW}$  = Stack Gas Wet Volumetric Flow at Standard Conditions (ft<sup>3</sup>/hr)  
 $A_S$  = Stack Area (ft<sup>2</sup>)  
 $Q_{SD}$  = Stack Gas Flow @ Std. Conditions, dry basis (dscf/hr)  
 $DGF$  = Dry Gas Fraction

### Volumetric Flow

#### South Fresh Air Run 1 Example

$$V_S = \left( 85.49 \frac{ft}{sec} \sqrt{\frac{(lb/lb \text{ mol})(\text{" Hg})}{(\text{ }^\circ R)(\text{" H}_2\text{O})}} \right) (0.84) (1.227 \text{ " H}_2\text{O}) \sqrt{\frac{771 \text{ }^\circ R}{(29.83 \text{ " Hg})(28.5 \text{ lb/lb mol})}} = \underline{83.9 \text{ ft/sec}}$$

$$Q_W = \left( \frac{83.9 \text{ ft}}{sec} \right) \left( \frac{9.621 \text{ ft}^2}{1} \right) \left( \frac{3600 \text{ sec}}{hr} \right) = \underline{2.91 \times 10^6 \text{ cf/hr}}$$

$$Q_{SW} = \left( \frac{2.91 \times 10^6 \text{ cf}}{hr} \right) \left( \frac{528 \text{ }^\circ R}{771 \text{ }^\circ R} \right) \left( \frac{29.83 \text{ " Hg}}{29.92 \text{ " Hg}} \right) = \underline{1.98 \times 10^6 \text{ scf/hr}}$$

$$Q_{SD} = (1.98 \times 10^6) (0.952) = \underline{1.89 \times 10^6 \text{ dscf/hr}}$$

**NOx and CO Concentration and Emission Rate**

$$E_{Gas} = \frac{(C_{Gas})(Q_{SD})(Gas_{MW})(28.32 \text{ L/ft}^3)}{(10^6 \text{ ppmv})(24.056 \text{ L/mol})(453.6 \text{ g/lb})}$$

where:  $C_{Gas}$  = Effluent Concentration (*dry ppmv*)

$E_{Gas}$  = Emission of Gas, (*lb/hr*)

$C_{Gas}$  = Concentration of Gas, (*dry ppmv*)

$Q_{SD}$  = Stack Gas Flow @ Std. Conditions, dry basis (*dscf/hr*)

$Gas_{MW}$  = Molecular Weight of Gas (*g/g mol*) Where:

$NO_{xMW}$  = Molecular Weight of NOx (*46.01 g/g mol*)

$CO_{MW}$  = Molecular Weight of CO (*28.01 g/g mol*)

**Pollutant Gas Emissions South Run #1 Example**

$$E_{NOx} = \frac{(19.6 \text{ ppmv NOx})(1.89 \times 10^6 \text{ dscf/hr})(46.01 \text{ g/gmol})(28.32 \text{ L/ft}^3)}{(10^6 \text{ ppmv})(24.056 \text{ L/mol})(453.6 \text{ g/lb})} = \underline{4.42 \text{ lb/hr}}$$

$$E_{CO} = \frac{(16.3 \text{ ppmv CO})(1.89 \times 10^6 \text{ dscf/hr})(28.01 \text{ g/gmol})(28.32 \text{ L/ft}^3)}{(10^6 \text{ ppmv})(24.056 \text{ L/mol})(453.6 \text{ g/lb})} = \underline{2.24 \text{ lb/hr}}$$