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AIR EMISSION TEST REPORT FOR THE VERIFICATION OF AIR POLLUTANT EMISSIONS FROM LANDFILL GAS FUELED TURBINES

Prepared for:

ARBOR HILLS ENERGY, LLC
SRN N2688

ICT Project No.: 2300185

December 8, 2023

IMPACT COMPLIANCE & TESTING

Report Certification

AIR EMISSION TEST REPORT
FOR THE
VERIFICATION OF AIR POLLUTANT EMISSIONS
FROM
LANDFILL GAS FUELED TURBINES

Arbor Hills Energy, LLC
Northville, MI

The material and data in this document were prepared under the supervision and direction of the undersigned.

Report Prepared By:
Blake Beddow Senior Project Manager Impact Compliance & Testing, Inc.

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1.0 Introduction

Arbor Hills Energy, LLC (Arbor Hills Energy) operates three (3) EGT Typhoon gas-fired turbines and one (1) Solar Taurus gas-fired turbine at its renewable energy facility located at the Arbor Hills Landfill in Northville, Washtenaw County, Michigan. The turbines are fueled by landfill gas (LFG) that is collected from the Arbor Hills Landfill. Testing was performed with only the turbines in operation. Currently, the facility does not run or plan to run the duct burners in the foreseeable future. In the event that the duct burners are planned to be run, testing will be performed prior to them being placed in routine operation.

The conditions of Renewable Operating (RO) Permit No. MI-ROP-N2688-2011a, and Permit to Install (PTI) No. 68-23 issued to the facility specify that for EUTURBINE/DB1, EUTURBINE/DB2, EUTURBINE/DB3 (collectively, FGTURBINES) and EUTURBINE4, verification of the following emission rates is required: for nitrogen oxides (NOx), carbon monoxide (CO), sulfur dioxide (SO_2), volatile organic compounds (VOC), formaldehyde (HCOH), and hydrogen chloride (HCl).

The compliance testing presented in this report was performed by Impact Compliance & Testing, Inc. (ICT), a Michigan-based environmental consulting and testing company. ICT representatives Andy Rusnak, Andrew Eisenberg, and Blake Beddow performed the field sampling and measurements on October 18-19, 2023.

The turbine emission performance tests consisted of triplicate, one-hour sampling periods for NOx, CO, SO_2, VOC, HCOH and HCl. Exhaust gas velocity, moisture, oxygen (O_2) content, and carbon dioxide (CO_2) content were determined for each test period to calculate volumetric exhaust gas flowrate and pollutant mass emission rates.

The exhaust gas sampling and analysis was performed using procedures specified in the Test Plan dated September 13, 2023, that was reviewed and approved by the State of Michigan Department of Environment, Great Lakes, and Energy-Air Quality Division (EGLE-AQD). Mr. Andrew Riley and Ms. Diane Kavanaugh Vetort of EGLE-AQD observed portions of the compliance testing.

Questions regarding this air emission test report should be directed to:

Test Methods and Procedures	Facility Compliance Manager	Responsible Official
Blake Beddow Sr. Project Manager Impact Compliance & Testing, Inc. 37660 Hills Tech Drive Farmington Hills, MI 48331 (734) 357-8383 blake.beddow@impactcandt.com	Suparna Chakladar Vice President – Fuel Supply & Environmental Services Opal Fuels 5087 Junction Road Lockport, NY 14094 (951) 833-4153 schakladar@opalfuels.com	Anthony Falbo Chief Operating Officer Opal Fuels

2.0 Summary of Test Results and Operating Conditions

2.1 Purpose and Objective of the Tests

Stack testing was performed to measure NOx, CO, SO_2, VOC, HCOH, and HCl emissions for three (3) EGT Typhoon turbines that are identified as EUTURBINE/DB1, EUTURBINE/DB2, and EUTURBINE/DB3 (collectively, FGTURBINES) and one (1) Solar Taurus turbine that is identified as EUTURBINE4 and to satisfy the annual and 5-year testing requirements specified in RO Permit No. MI-ROP-N2688-2011a and PTI No. 68-23.

The compliance test results presented in this report are for testing that was performed on October 18-19, 2023.

2.2 Operating Conditions During the Compliance Tests

Testing was performed while the unit operated at normal, maximum levels during the test periods. Fuel flowrate (standard cubic feet per minute (scfm)), fuel methane content (%), power production (kW/MW), and verification of no duct burner fuel usage (scfm) were recorded at 15-minute intervals for each test period. Turbine Heat Input (MMBtu/hr) was calculated based off the analyzed fuel samples.

Appendix 2 provides operating records provided by Arbor Hills Energy representatives for the test periods. Appendix 4 provides turbine heat input calculations. Appendix 7 presents lab reports for the fuel samples.

Table 2.1 presents a summary of the average turbine process operating conditions during the test periods.

2.3 Summary of Air Pollutant Sampling Results

The gas exhausted from each LFG fueled turbine was sampled for three (3) one-hour test periods during the compliance testing performed October 18-19, 2023.

Tables 2.2 and 2.3 present the average measured pollutant emission rates for the turbines (average of the three test periods).

Test results for each one-hour sampling period and comparison to the permitted emission rates are presented in Section 6.0 of this report.

Table 2.1 Average turbine operating conditions during the test periods

Turbine Parameter	EUTURBINE/ DB1	EUTURBINE/ DB2	EUTURBINE/ DB3	EUTURBINE4
Turbine Output (MW)	4.43	3.26	4.46	4.77
Turbine Fuel Use (scfm)	1,920	1,645	1,979	2,185
LFG Methane Content (%)	49.0	50.2	50.0	50.9
Duct Burner Fuel Use (scfm)	0.0	0.0	0.0	N/A
Turbine Heat Input (MMBtu/hr)	53.2	46.3	56.5	62.4

Table 2.2 Measured emission rates for FGTURBINES (three-test average)

Emission Unit	NO_x		CO	SO_2	VOC[1]	HCOH	HCl
	lb/hr	ppmvd @ 15% O_2, ISO	lb/hr	lb/hr	lb/hr	lb/MMBtu	lb/hr
EUTURBINE/DB1	6.70	35.6	5.34	0.3	0.14	$1.1x10^{-3}$	0.17
EUTURBINE/DB2	6.17	37.6	2.97	0.3	0.05	$9.8x10^{-4}$	0.17
EUTURBINE/DB3	7.28	37.6	5.43	0.3	0.12	$1.4x10^{-3}$	0.18
Emission Limit	*11.3*	*> 150*[3]	*15.4*	*0.5*	*2.9*	*1.072*	*1.9*

1. VOC emission rate includes formaldehyde (HCOH).
2. Emission concentration of NO_x at 15 percent O_2 and ISO standard ambient conditions ppmvd.
3. Each turbine's allowable NOx emission concentration is dependent on fuel sample variables. Please see Section 6.0 and table 6.1, 6.2, and 6.3 for each turbine's allowable NOx emission concentration.

Table 2.3 Measured emission rates for EUTURBINE4 (three-test average)

Emission Unit	NO_x		CO	SO_2		VOC[1]	HCOH	HCl
	lb/hr	ppmvd @ 15% O_2	lb/hr	lb/hr	lb/MMBtu	lb/hr	lb/MMBtu	lb/hr
EUTURBINE4	6.0	26	11.1	0.30	$4.8x10^{-3}$	0.25	$3.1x10^{-3}$	0.23
Emission Limit	*8.49*	*74*	*13.2*	*0.41*	*0.15*	*0.80*	*1.072*	*0.6*

1. VOC emission rate includes formaldehyde (HCOH).

3.0 Source and Sampling Location Description

3.1 General Process Description

Landfill gas (LFG) containing methane is generated in the Landfill from the anaerobic decomposition of disposed waste materials. The LFG is collected from both active and capped landfill cells using a system of wells (gas collection system). The collected LFG is transferred to the Arbor Hills Energy facility where it is treated and used as fuel to produce electricity, which is transferred to the local utility.

3.2 Rated Capacities and Air Emission Controls

FGTURBINES and EUTURBINE4 are fueled exclusively with LFG recovered from the adjacent Landfill, transferred to Arbor Hills Energy, and treated (compressed, dewatered, sulfur removed, and filtered) prior to its use as fuel. The fuel (treated LFG) consumption rate for FGTURBINES and EUTURBINE4 is regulated automatically to maintain the required heat input rate to support the desired operating rate and is dependent on the fuel heat value (methane content).

FGTURBINES typically produce 3.2-4.5 Megawatts (MW) of electricity and EUTURBINE4 typically produces up to 5.2 MW. The combustion turbines are not equipped with add-on emission control equipment. NOX emissions are suppressed using dry low-NOX combustors.

3.3 Sampling Locations

The turbine exhaust gas is released to the atmosphere through a dedicated vertical exhaust stack with a vertical release point.

The sampling ports for FGTURBINES are identical and are located in the exhaust stack, which has an inner diameter of 45 inches. Four (4) sampling ports are located 90° offset from one another and provide a sampling location 98 inches (2.17 duct diameters) upstream and 240 inches (5.33 duct diameters) downstream from any flow disturbance. These dimensions satisfy the USEPA Method 1 criteria for a representative sample location. Individual traverse points were determined in accordance with USEPA Method 1.

The sampling ports for EUTURBINE4 are located in the exhaust stack, which has an inner diameter of 42 inches. Three (3) sampling ports are located 90° offset from one another and provide a sampling location 8.33 feet (2.38 duct diameters) upstream and 15.5 feet (4.43 duct diameters) downstream from any flow disturbance. These dimensions satisfy the USEPA Method 1 criteria for a representative sample location.
Individual traverse points were determined in accordance with USEPA Method 1.

All sample port locations satisfy the USEPA Method 1 criteria for a representative sample location.

Appendix 1 provides diagrams of the emission test sampling locations.

4.0 Sampling and Analytical Procedures

A Stack Test Protocol for the air emission testing was reviewed and approved by EGLE-AQD. This section provides a summary of the sampling and analytical procedures that were used during the testing periods.

4.1 Summary of Sampling Methods

USEPA Method 1	Exhaust gas velocity measurement locations were determined based on the physical stack arrangement and requirements in USEPA Method 1.
USEPA Method 2	Exhaust gas velocity pressure was determined using a Type-S Pitot tube connected to a red oil incline manometer; temperature was measured using a K-type thermocouple connected to the Pitot tube.
USEPA Method 3A	Exhaust gas O_2 and CO_2 content was determined using paramagnetic and infrared instrumental analyzers, respectively.
USEPA Method 4	Exhaust gas moisture was determined based on the water weight gain in chilled impingers.
USEPA Method 7E	Exhaust gas NOx concentration was determined using chemiluminescence instrumental analyzers.
USEAP Method 10	Exhaust gas CO concentration was determined using infrared instrumental analyzers.
GPA Method 2261	Fuel gas methane and heat content analysis by gas chromatography.
ASTM Method D-5504	Fuel gas sulfur analysis by gas chromatography and chemiluminescence.
ASTM Method D-6348	Exhaust gas formaldehyde and SO_2 concentrations were determined using an FTIR instrumental analyzer.

4.2 Exhaust Gas Velocity Determination (USEPA Method 2)

The turbine exhaust stack gas velocities and volumetric flow rates were determined using USEPA Method 2 during each test period. An S-type Pitot tube connected to a red-oil manometer was used to determine velocity pressure at each traverse point across the stack cross section. Gas temperature was measured using a K-type thermocouple mounted to the Pitot tube. The Pitot tube and connective tubing were leak-checked periodically throughout the test periods to verify the integrity of the measurement system.

The absence of significant cyclonic flow at the sampling location was verified using an S-type Pitot tube and oil manometer. The Pitot tube was positioned at each velocity traverse point with the planes of the face openings of the Pitot tube perpendicular to the stack cross-sectional plane. The Pitot tube was then rotated to determine the null angle (rotational angle as measured from the perpendicular, or reference, position at which the differential pressure is equal to zero).

Appendix 3 provides exhaust gas flowrate calculations and field data sheets.

4.3 Exhaust Gas Molecular Weight Determination (USEPA Method 3A)

CO_2 and O_2 content in the turbine exhaust gas stream was measured continuously throughout each test period in accordance with USEPA Method 3A. The CO_2 content of the exhaust was monitored using a M&C GenTwo infrared gas analyzer. The O_2 content of the exhaust was monitored using a M&C GenTwo gas analyzer that uses a paramagnetic sensor.

During each sampling period, a continuous sample of the turbine exhaust gas stream was extracted from the stack using a stainless-steel probe connected to a Teflon® heated sample line. The sampled gas was conditioned by removing moisture prior to being introduced to the analyzers; therefore, measurement of O_2 and CO_2 concentrations correspond to standard dry gas conditions. Instrument response data were recorded using an ESC Model 8816 data acquisition system that monitored the analog output of the instrumental analyzers continuously and logged data as one-minute averages.

Prior to, and at the conclusion of each test, the instruments were calibrated using upscale calibration and zero gas to determine analyzer calibration error and system bias (described in Section 5.0 of this document). Sampling times were recorded on field data sheets.

Appendix 4 provides O_2 and CO_2 calculation sheets. Raw instrument response data are provided in Appendix 5.

4.4 Exhaust Gas Moisture Determination (USEPA Method 4)

Moisture content of the turbine exhaust gas was determined in using the USEPA Method 4 chilled impinger method as part of the isokinetic sampling procedures for HCl. The amount of moisture removed from the sample stream by the chilled impingers was determined gravimetrically by weighing the impinger contents before and after the test period to determine net weight gain.

Appendix 3 provides moisture train sampling data and calculations.

4.6 NO_x and CO Concentration Measurements (USEPA Method 7E and 10)

NO_X and CO pollutant concentrations in the turbine exhaust gas streams were determined using a Thermo Environmental Instruments, Inc. (TEI) Model 42i High Level chemiluminescence NO_X analyzer and an M&C GenTwo infared CO analyzer.

Throughout each test period, a continuous sample of the turbine exhaust gas was extracted from the stack using the Teflon® heated sample line and gas conditioning system and delivered to the instrumental analyzers. Instrument response for each analyzer was recorded on an ESC Model 8816 data acquisition system that logged data as one-minute averages. Prior to, and at the conclusion of each test, the instruments were calibrated using upscale calibration and zero gas to determine analyzer calibration error and system bias.

Appendix 4 provides CO and NO_X calculation sheets. Raw instrument response data are provided in Appendix 5.

4.7 HCl by Sampling Train (USEPA Method 26)

HCl concentrations in the turbine exhaust gas were determined using a modified version of USEPA Method 26. A sample of the exhaust gas was withdrawn from the exhaust stack at a constant rate (i.e., non-isokinetic rate) using a glass lined probe and a quartz filter. The gas sample was bubbled through chilled impingers containing 0.1 normality sulfuric acid (0.1N H2SO4). The NaOH portion of the Method 26 sampling train was not used since halogen (Cl2) concentrations were not included in the analysis.

The wetted portions of the sampling train were constructed of glass. A silonite-coated stainless-steel probe union was used. At the end of each one-hour test period, the impinger solutions and rinses were recovered and shipped to a third-party laboratory (Enthalpy Analytical in Durham, North Carolina) for HCl analysis by ion chromatography (IC) analysis in accordance with USEPA Method 26.

Appendix 4 provides HCl calculation sheets. Appendix 8 provides a copy of the HCl laboratory analytical report.

4.8 Fuel Gas Analysis (ASTM D-5504 and GPA 2261)

In addition to the exhaust gas SO_2 concentration measurements, three (3) samples of the treated LFG used as fuel were analyzed for sulfur content and for methane content and heat content. Two (2) samples of the treated LFG were collected on October 18, 2023 (the day Turbine Nos. 1 and 2 were tested) using canisters. One (1) sample of the treated LFG was collected on October 19, 2023 (the day Turbine Nos. 3 and 4 were tested) using tedlar bags. For each sample, sample tubing was connected to the fuel header at a location after the treatment system and gas blower.

The gas samples were analyzed by SPL (Traverse City, MI). Each gas sample was analyzed for sulfur bearing compounds by ASTM D-5504, and for methane content and heat content by GPA 2261.

In addition, inlet LFG was sampled for hydrogen sulfide (H_2S) concentrations during each LFG sample collection period using Draeger® tubes. Arbor Hills Energy representatives also sampled the LFG pre and post Sulfur Treatment System (STS) on each day of testing.

Appendix 4 provides the SO_2 emission rates calculations based on analysis of the gas sample. Appendix 7 provides a copy of the laboratory analytical report for the treated LFG samples and photos of the Draeger® tubes.

4.9 Measurement of SO_2 and HCOH Concentrations via FTIR (ASTM D6348)

SO_2 and HCOH concentrations in the turbine exhaust gas stream were determined using an MKS Multi-Gas 2030 Fourier transform infrared (FTIR) spectrometer in accordance with test method ASTM D6348.

Samples of the exhaust gas were delivered directly to the instrumental analyzer using a Teflon® heated sample line to prevent condensation. The sample to the FTIR analyzer was not conditioned to remove moisture. Therefore, measurements correspond to standard conditions with no moisture correction (wet basis).

A calibration transfer standard (CTS), ethylene standard, and nitrogen zero gas were analyzed before and after each test run. Analyte spiking, of the turbine, with acetaldehyde, SO_2, and sulfur hexafluoride was performed to verify the ability of the sampling system to quantitatively deliver a sample containing the compound of interest from the base of the probe to the FTIR. Data was collected at 0.5 cm-1 resolution. Instrument response was recorded using MG2000 data acquisition software.

Appendix 4 provides HCOH and SO_2 calculation sheets. Moisture content data is provided in the flowrate calculations presented in Appendix 3. Raw instrument response data for the FTIR analyzer is provided in Appendix 5.

5.0 QA/QC Activities

5.1 Flow Measurement Equipment

Prior to arriving onsite, the instruments used during the source test to measure exhaust gas properties and velocity (pyrometer, Pitot tube, and scale) were calibrated to specifications in the sampling methods.

The absence of cyclonic flow for each sampling location was verified using an S-type Pitot tube and oil manometer. The Pitot tube was positioned at each of the velocity traverse points with the planes of the face openings of the Pitot tube perpendicular to the stack cross-sectional plane. The Pitot tube was then rotated to determine the null angle (rotational angle as measured from the perpendicular, or reference, position at which the differential pressure is equal to zero).

5.2 NO_x Converter Efficiency Test

The NO_2 – NO conversion efficiency of the Model 42i analyzer was verified prior to the testing program. A USEPA Protocol 1 certified concentration of NO_2 was injected directly into the analyzer, following the initial three-point calibration, to verify the analyzer's conversion efficiency. The analyzer's NO_2 – NO converter uses a catalyst at high temperatures to convert the NO_2 to NO for measurement. The conversion efficiency of the analyzer is deemed acceptable if the measured NO_2 concentration is within 90% of the expected value.

The NO_2 – NO conversion efficiency test satisfied the USEPA Method 7E criteria (measured NO_2 concentration was 103.8% of the expected value).

5.3 Gas Divider Certification (USEPA Method 205)

A STEC Model SGD-710C 10-step gas divider was used to obtain appropriate calibration span gases. The ten-step STEC gas divider was NIST certified (within the last 12 months) with a primary flow standard in accordance with Method 205. When cut with an appropriate zero gas, the ten-step STEC gas divider delivered calibration gas values ranging from 0% to 100% (in 10% step increments) of the USEPA Protocol 1 calibration gas that was introduced into the system. The field evaluation procedures presented in Section 3.2 of Method 205 were followed prior to use of gas divider. The field evaluation yielded no errors greater than 2% of the triplicate measured average and no errors greater than 2% from the expected values.

5.4 Instrumental Analyzer Interference Check

The instrumental analyzers used to measure NO_X, CO, O_2 and CO_2 have had an interference response test preformed prior to their use in the field, pursuant to the interference response test procedures specified in USEPA Method 7E. The appropriate interference test gases (i.e., gases that would be encountered in the exhaust gas stream) were introduced into each analyzer, separately and as a mixture with the analyte that each analyzer is designed to measure. All of analyzers exhibited a composite deviation of less than 2.5% of the span for all measured interferent gases. No major analytical components of the analyzers have been replaced since performing the original interference tests.

5.5 Instrument Calibration and System Bias Checks

At the beginning of each day of the testing program, initial three-point instrument calibrations were performed for the NO_x, CO, CO_2 and O_2 analyzers by injecting calibration gas directly into the inlet sample port for each instrument. System bias checks were performed prior to and at the conclusion of each sampling period by introducing the upscale calibration gas and zero gas into the sampling system (at the base of the stainless-steel sampling probe prior to the particulate filter and Teflon® heated sample line) and determining the instrument response against the initial instrument calibration readings.

At the beginning of each test day, appropriate high-range, mid-range, and low-range span gases followed by a zero gas were introduced to the NMHC analyzer, in series at a tee connection, which is installed between the sample probe and the particulate filter, through a poppet check valve. After each one-hour test period, mid-range and zero gases were re-introduced in series at the tee connection in the sampling system to check against the method's performance specifications for calibration drift and zero drift error.

The instruments were calibrated with USEPA Protocol 1 certified concentrations of CO_2, O_2, NO_x, and SO_2 in nitrogen and zeroed using hydrocarbon free nitrogen. The NMHC (VOC) instrument was calibrated with USEPA Protocol 1 certified concentrations of propane in air and zeroed using hydrocarbon-free air. A STEC Model SGD-710C ten-step gas divider was used to obtain intermediate calibration gas concentrations as needed.

5.6 Determination of Exhaust Gas Stratification

A stratification test was performed for each turbine exhaust stack. The stainless-steel sample probe was positioned at sample points according to USEPA Method 1. Pollutant concentration data were recorded at each sample point for a minimum of twice the maximum system response time.

The recorded concentration data for each turbine exhaust stack indicated that the measured NOx concentrations did not vary by more than 5% of the mean across the stack diameter. Therefore, each turbine exhaust gas stream was considered to not be stratified and the compliance test sampling was performed at a single point (centroid) within each turbine exhaust stack.

5.7 System Response Time

The response time of the sampling system was determined prior to the compliance test program by introducing upscale gas and zero gas, in series, into the sampling system using a tee connection at the base of the sample probe. The elapsed time for the analyzer to display a reading of 95% of the expected concentration was determined using a stopwatch.

Sampling periods did not commence until the sampling probe had been in place for at least twice the greatest system response time.

5.8 Meter Box Calibrations

The dry gas meter sampling console used for moisture testing was calibrated prior to and after the testing program. This calibration uses the critical orifice calibration technique presented in USEPA Method 5. The metering console calibration exhibited no data outside the acceptable ranges presented in USEPA Method 5.

The digital pyrometer in the metering consoles were calibrated using a NIST traceable Omega® Model CL 23A temperature calibrator.

5.9 Cyclonic Flow Check

The absence of cyclonic flow for each sampling location was verified using an S-type Pitot tube and oil manometer. The Pitot tube was positioned at multiple velocity traverse points with the planes of the face openings of the Pitot tube perpendicular to the stack cross-sectional plane. The Pitot tube was then rotated to determine the null angle (rotational angle as measured from the perpendicular, or reference, position at which the differential pressure is equal to zero).

Appendix 6 presents test equipment quality assurance data (NO_2 – NO conversion efficiency test data, instrument calibration and system bias check records, calibration gas and gas divider certifications, interference test results, meter box calibration records, field equipment calibration records, and stratification checks).

5.10 FTIR QA/QC Activities

At the beginning of each day a calibration transfer standard (CTS, ethylene gas), analyte of interest (acetaldehyde and sulfur hexafluoride) and nitrogen calibration gas was directly injected into the FTIR to evaluate the unit response.

Prior to and after each test run the CTS was analyzed. The ethylene was passed through the entire system (system purge) to verify the sampling system response and to ensure that the sampling system remained leak-free at the stack location. Nitrogen was also passed through the sampling system to ensure the system was free of contaminants.

Analyte spiking, of each emission unit, with acetaldehyde was performed to verify the ability of the sampling system to quantitatively deliver a sample containing the compound of interest from the base of the probe to the FTIR and assure the ability of the FTIR to quantify that compound in the presence of effluent gas.

As part of the data validation procedure, reference spectra were manually fit to that of the sample spectra (two spectra from each test period) and a concentration was determined.

Concentration data was manually validated using the MKS MG2000 method analyzer software. The software used multi-point calibration curves to quantify each spectrum. The software-calculated results were compared with the measured concentrations to ensure the quality of the data.

Appendix 7 presents test equipment quality assurance data (NO_2 – NO conversion efficiency test data, instrument calibration and system bias check records, calibration gas and gas divider certifications, interference test results, FTIR QA/QC data, stratification checks, and field equipment calibration records).

6.0 Results

6.1 Test Results and Allowable Emission Limits

Turbine operating data and air pollutant concentration and emission measurement results for each one-hour test period are presented in Tables 6.1 through 6.4.

Each turbine under FGTURBINES has the following allowable emission limits specified in PTI 68-23:

- 11.3 lb/hr, and fuel based emission factor (40 cfr 60.332(A)(2) Subpart GG) for NO_x.
- 15.4 lb/hr for CO.
- 0.5 lb/hr for SO_2.
- 2.9 lb/hr (includes HCOH) for VOC.
- 1.072 lb/MMBtu for HCOH.
- 1.9 lb/hr for HCl.

EUTURBINE4 has the following allowable emission limits specified in PTI 68-23:

- 8.49 lb/hr and 74 ppm @ 15% O_2 for NO_x.
- 13.2 lb/hr for CO.
- 0.41 lb/hr and 0.15 lb/MMBtu for SO_2.
- 0.80 lb/hr (includes HCOH) for VOC.
- 1.072 lb/MMBtu for HCOH.
- 0.60 lb/hr for HCl.

The measured air pollutant concentrations and emission rates for FGTURBINES and EUTURBINE4 are less than the allowable limits specified in PTI 68-23.

6.2 Variations from Normal Sampling Procedures or Operating Conditions

The testing for all pollutants was performed in accordance with USEPA methods and the approved Stack Test Protocol dated September 13, 2023. The turbine operated at maximum achievable load conditions during the test periods.

Table 6.1 Measured exhaust gas conditions and air pollutant emission rates for Turbine No. 1 (EUTURBINE/DB1)

Test No. Test date Test period (24-hr clock)	1 10/18/2023 0720-0750, 0752-0822	2 10/18/2023 0900-0938, 1015-1037	3 10/18/2023 1112-1212	Three Test Average
Fuel flowrate (scfm)	1,975	1,924	1,861	1,920
Turbine output (kW)	4,552	4,455	4,284	4,430
Turbine output (MW)	4.55	4.46	4.28	4.42
LFG methane content (%)	48.6	49.1	49.5	49.0
Duct burner fuel use (scfm)	0.0	0.0	0.0	0.0
Turbine Heat Input (MMBtu/hr)	54.8	53.3	51.6	53.2
<u>Exhaust Gas Composition</u>				
CO_2 content (% vol)	5.66	5.61	5.64	5.64
O_2 content (% vol)	15.2	15.3	15.3	15.3
Moisture (% vol)	7.29	6.78	6.88	6.98
Exhaust gas flowrate (scfm)	30,703	31,354	30,162	30,740
Exhaust gas flowrate (dscfm)	28,465	29,228	28,087	28,593
Exhaust gas temperature (°F)	956	923	929	936
<u>Nitrogen Oxides</u>				
NO_X conc. (ppmvd)	32.9	32.7	32.3	32.7
NO_X emissions (lb/hr)	6.72	6.86	6.50	6.70
Permit Limit (lb/hr)	-	-	-	*11.3*
NO_X emissions (ppmvd @ 15% O_2)	34.3	34.5	34.0	34.3
NO_X emissions (ppmvd @ 15% O_2, ISO Corrected)	35.9	35.8	35.1	35.6
Emission Limit (ppmvd @ 15% O_2, ISO Corrected)[1]	-	-	-	*195*
<u>Carbon Monoxide</u>				
CO conc. (ppmvd)	46.9	42.0	39.5	42.8
CO emissions (lb/hr)	5.83	5.36	4.84	5.34
Permit Limit (lb/hr)	-	-	-	*15.4*
<u>Sulfur Dioxide</u>				
SO_2 conc. (ppmv)	1.12	0.98	0.86	0.99
SO_2 emissions (lb/hr)	0.34	0.31	0.26	0.30
Permit Limit (lb/hr)	-	-	-	*0.5*
<u>Hydrogen Chloride</u>				
HCl conc. (ug)	1,952	1,897	2,002	1,950
HCl emissions (lb/hr)	0.17	0.17	0.18	0.17
Permit Limit (lb/hr)	-	-	-	*1.9*

1. Each turbine's allowable NOx emission concentration is dependent on fuel sample variables. Calculations are presented in Appendix 4.

Table 6.1 Measured exhaust gas conditions and air pollutant emission rates for Turbine No. 1 (EUTURBINE/DB1), Continued

Test No. Test date Test period (24-hr clock)	1 10/18/2023 0720-0750, 0752-0822	2 10/18/2023 0900-0938, 1015-1037	3 10/18/2023 1112-1212	Three Test Average
Fuel flowrate (scfm)	1,975	1,924	1,861	1,920
Turbine output (kW)	4,552	4,455	4,284	4,430
Turbine output (MW)	4.55	4.46	4.28	4.42
LFG methane content (%)	48.6	49.1	49.5	49.0
Duct burner fuel use (scfm)	0.0	0.0	0.0	0.0
Turbine Heat Input (MMBtu/hr)	54.8	53.3	51.6	53.2
<u>Exhaust Gas Composition</u>				
CO_2 content (% vol)	5.66	5.61	5.64	5.64
O_2 content (% vol)	15.2	15.3	15.3	15.3
Moisture (% vol)	7.29	6.78	6.88	6.98
Exhaust gas flowrate (scfm)	30,703	31,354	30,162	30,740
Exhaust gas flowrate (dscfm)	28,465	29,228	28,087	28,593
Exhaust gas temperature (°F)	956	923	929	936
<u>Formaldehyde</u>				
HCOH conc. (ppmv)	0.43	0.45	0.34	0.40
HCOH emissions (lb/hr)	0.06	0.07	0.05	0.06
HCOH emissions (lb/MMBtu)	$1.1x10^{-3}$	$1.2x10^{-3}$	$9.3x10^{-4}$	$1.1x10^{-3}$
Permit Limit (lb/MMBtu)	-	-	-	*1.072*
<u>Volatile Organic Compounds</u>				
VOC conc. (ppmv)	0.18	0.94	0.06	*0.40*
VOC emissions (lb/hr)[2]	*0.10*	*0.27*	*0.07*	*0.15*
Permit Limit (lb/hr)	-	-	-	*2.9*

2. VOC emission rate includes formaldehyde.

Table 6.2 Measured exhaust gas conditions and air pollutant emission rates for Turbine No. 2 (EUTURBINE/DB2)

Test No. Test date Test period (24-hr clock)	1 10/18/2023 1245-1315, 1319-1349	2 10/18/2023 1417-1517	3 10/18/2023 1542-1642	Three Test Average
Fuel flowrate (scfm)	1,655	1,644	1,637	1,6454
Turbine output (kW)	3,336	3,234	3,212	3,261
Turbine output (MW)	3.34	3.23	3.21	3.26
LFG methane content (%)	50.1	50.3	50.3	50.2
Duct burner fuel use (scfm)	0.0	0.0	0.0	0.0
Turbine Heat Input (MMBtu/hr)	46.6	46.3	46.1	46.3
<u>Exhaust Gas Composition</u>				
CO_2 content (% vol)	5.22	5.21	5.21	5.21
O_2 content (% vol)	15.7	15.7	15.8	15.8
Moisture (% vol)	6.50	6.58	6.32	6.47
Exhaust gas flowrate (scfm)	28,842	28,217	28,409	28,489
Exhaust gas flowrate (dscfm)	26,967	26,360	26,613	26,646
Exhaust gas temperature (°F)	903	900	906	903
<u>Nitrogen Oxides</u>				
NO_X conc. (ppmvd)	32.2	32.4	32.4	32.3
NO_X emissions (lb/hr)	6.22	6.11	6.18	6.17
Permit Limit (lb/hr)	-	-	-	*11.3*
NO_X emissions (ppmvd @ 15% O_2)	36.8	37.0	37.2	34.3
NO_X emissions (ppmvd @ 15% O_2, ISO Corrected)	37.7	37.8	37.3	37.6
Emission Limit (ppmvd @ 15% O_2, ISO Corrected)[1]	-	-	-	*166*
<u>Carbon Monoxide</u>				
CO conc. (ppmvd)	24.2	26.4	26.0	25.5
CO emissions (lb/hr)	2.84	3.04	3.02	2.97
Permit Limit (lb/hr)	-	-	-	*15.4*
<u>Sulfur Dioxide</u>				
SO_2 conc. (ppmv)	0.78	0.94	0.92	0.88
SO_2 emissions (lb/hr)	0.23	0.26	0.26	0.25
Permit Limit (lb/hr)	-	-	-	*0.5*
<u>Hydrogen Chloride</u>				
HCl conc. (ug)	2,018	2,024	2,070	2,037
HCl emissions (lb/hr)	0.17	0.17	0.17	0.17
Permit Limit (lb/hr)	-	-	-	*1.9*

1. Each turbine's allowable NOx emission concentration is dependent on fuel sample variables. Calculations are presented in Appendix 4.

Table 6.2 Measured exhaust gas conditions and air pollutant emission rates for Turbine No. 2 (EUTURBINE/DB2), Continued

Test No. Test date Test period (24-hr clock)	1 10/18/2023 1245-1315, 1319-1349	2 10/18/2023 1417-1517	3 10/18/2023 1542-1642	Three Test Average
Fuel flowrate (scfm)	1,655	1,644	1,637	1,6454
Turbine output (kW)	3,336	3,234	3,212	3,261
Turbine output (MW)	3.34	3.23	3.21	3.26
LFG methane content (%)	50.1	50.3	50.3	50.2
Duct burner fuel use (scfm)	0.0	0.0	0.0	0.0
Turbine Heat Input (MMBtu/hr)	46.6	46.3	46.1	46.3
Exhaust Gas Composition				
CO_2 content (% vol)	5.22	5.21	5.21	5.21
O_2 content (% vol)	15.7	15.7	15.8	15.8
Moisture (% vol)	6.50	6.58	6.32	6.47
Exhaust gas flowrate (scfm)	28,842	28,217	28,409	28,489
Exhaust gas flowrate (dscfm)	26,967	26,360	26,613	26,646
Exhaust gas temperature (°F)	903	900	906	903
Formaldehyde				
HCOH conc. (ppmv)	0.33	0.35	0.34	0.34
HCOH emissions (lb/hr)	0.04	0.05	0.05	0.05
HCOH emissions (lb/MMBtu)	9.5×10^{-4}	9.9×10^{-4}	9.8×10^{-4}	9.8×10^{-4}
Permit Limit (lb/MMBtu)	-	-	-	*1.072*
Volatile Organic Compounds				
VOC conc. (ppmv)	0.00	0.00	0.00	*0.00*
VOC emissions (lb/hr)[2]	*0.04*	*0.05*	*0.05*	*0.05*
Permit Limit (lb/hr)	-	-	-	*2.9*

2. VOC emission rate includes formaldehyde.

Table 6.3 Measured exhaust gas conditions and air pollutant emission rates for Turbine No. 3 (EUTURBINE/DB3)

Test No. Test date Test period (24-hr clock)	1 10/19/2023 0701-0731, 0734-0804	2 10/19/2023 0830-0930	3 10/19/2023 0957-1057	Three Test Average
Fuel flowrate (scfm)	1,992	1,986	1,958	1,979
Turbine output (kW)	4,484	4,480	4,422	4,462
Turbine output (MW)	4.48	4.48	4.42	4.46
LFG methane content (%)	49.8	49.8	50.4	50.0
Duct burner fuel use (scfm)	0.0	0.0	0.0	0.0
Turbine Heat Input (MMBtu/hr)	56.9	56.7	55.9	56.5
<u>Exhaust Gas Composition</u>				
CO_2 content (% vol)	5.65	5.76	5.77	5.73
O_2 content (% vol)	15.3	15.2	15.2	15.2
Moisture (% vol)	6.72	7.03	7.11	6.95
Exhaust gas flowrate (scfm)	30,924	31,299	31,731	31,318
Exhaust gas flowrate (dscfm)	28,845	29,097	29,474	29,139
Exhaust gas temperature (°F)	940	940	939	940
<u>Nitrogen Oxides</u>				
NO_X conc. (ppmvd)	34.2	35.2	35.2	34.8
NO_X emissions (lb/hr)	7.08	7.34	7.43	7.28
Permit Limit (lb/hr)	-	-	-	*11.3*
NO_X emissions (ppmvd @ 15% O_2)	36.0	36.1	36.2	36.1
NO_X emissions (ppmvd @ 15% O_2, ISO Corrected)	37.3	37.8	37.6	37.6
Emission Limit (ppmvd @ 15% O_2, ISO Corrected)[1]	-	-	-	*184*
<u>Carbon Monoxide</u>				
CO conc. (ppmvd)	43.4	42.3	42.5	42.7
CO emissions (lb/hr)	5.46	5.38	5.46	5.43
Permit Limit (lb/hr)	-	-	-	*15.4*
<u>Sulfur Dioxide</u>				
SO_2 conc. (ppmv)	0.85	0.84	0.87	0.85
SO_2 emissions (lb/hr)	0.26	0.26	0.28	0.27
Permit Limit (lb/hr)	-	-	-	*0.5*
<u>Hydrogen Chloride</u>				
HCl conc. (ug)	1,973	1,970	2,082	2,008
HCl emissions (lb/hr)	0.17	0.17	0.20	0.18
Permit Limit (lb/hr)	-	-	-	*1.9*

1. Each turbine's allowable NOx emission concentration is dependent on fuel sample variables. Calculations are presented in Appendix 4.

Table 6.3 Measured exhaust gas conditions and air pollutant emission rates for Turbine No. 3 (EUTURBINE/DB3), Continued

Test No. Test date Test period (24-hr clock)	1 10/19/2023 0701-0731, 0734-0804	2 10/19/2023 0830-0930	3 10/19/2023 0957-1057	Three Test Average
Fuel flowrate (scfm)	1,992	1,986	1,958	1,979
Turbine output (kW)	4,484	4,480	4,422	4,462
Turbine output (MW)	4.48	4.48	4.42	4.46
LFG methane content (%)	49.8	49.8	50.4	50.0
Duct burner fuel use (scfm)	0.0	0.0	0.0	0.0
Turbine Heat Input (MMBtu/hr)	56.9	56.7	55.9	56.5
Exhaust Gas Composition				
CO_2 content (% vol)	5.65	5.76	5.77	5.73
O_2 content (% vol)	15.3	15.2	15.2	15.2
Moisture (% vol)	6.72	7.03	7.11	6.95
Exhaust gas flowrate (scfm)	30,924	31,299	31,731	31,318
Exhaust gas flowrate (dscfm)	28,845	29,097	29,474	29,139
Exhaust gas temperature (°F)	940	940	939	940
Formaldehyde				
HCOH conc. (ppmv)	0.54	0.53	0.56	0.54
HCOH emissions (lb/hr)	0.08	0.08	0.08	0.08
HCOH emissions (lb/MMBtu)	1.4×10^{-3}	1.4×10^{-3}	1.5×10^{-3}	1.4×10^{-3}
Permit Limit (lb/MMBtu)	-	-	-	*1.072*
Volatile Organic Compounds				
VOC conc. (ppmv)	0.18	0.15	0.19	*0.17*
VOC emissions (lb/hr)[2]	*0.12*	*0.11*	*0.12*	*0.12*
Permit Limit (lb/hr)	-	-	-	*2.9*

2. VOC emission rate includes formaldehyde.

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Table 6.4 Measured exhaust gas conditions and air pollutant emission rates for Turbine No. 4 (EUTURBINE4)

Test No.	1	2	3	
Test date	10/19/2023	10/19/2023	10/19/2023	Three Test
Test period (24-hr clock)	1202-1232, 1236-1306	1337-1437	1458-1558	Average
Fuel flowrate (scfm)	2,202	2,187	2,165	2,185
Turbine output (kW)	4,776	4,782	4,744	4,767
Turbine output (MW)	4.78	4.78	4.74	4.77
LFG methane content (%)	50.9	-	-	50.9
Duct burner fuel use (scfm)	0.0	0.0	0.0	0.0
Turbine Heat Input (MMBtu/hr)	62.9	62.5	61.8	62.4
Exhaust Gas Composition				
CO_2 content (% vol)	5.44	5.50	5.42	5.45
O_2 content (% vol)	15.5	15.5	15.5	15.5
Moisture (% vol)	7.20	7.14	6.49	6.94
Exhaust gas flowrate (scfm)	38,052	37,703	37,855	37,870
Exhaust gas flowrate (dscfm)	35,313	35,011	35,399	35,241
Exhaust gas temperature (°F)	944	931	935	937
Nitrogen Oxides				
NO_X conc. (ppmvd)	24.1	23.5	23.4	23.7
NO_X emissions (lb/hr)	6.10	5.91	5.93	5.98
Permit Limit (lb/hr)	-	-	-	*8.2*
NO_X emissions (ppmvd @ 15% O_2)	26.2	25.5	25.4	25.7
Emission Limit (ppmvd @ 15% $O_{2,}$)	-	-	-	*74*
Carbon Monoxide				
CO conc. (ppmvd)	71.6	74.7	70.5	72.3
CO emissions (lb/hr)	11.0	11.4	10.9	11.1
Permit Limit (lb/hr)	-	-	-	*13.2*
Sulfur Dioxide				
SO_2 conc. (ppmv)	0.78	0.78	0.82	0.79
SO_2 emissions (lb/hr)	0.30	0.29	0.31	0.30
Permit Limit (lb/hr)	-	-	-	*0.41*
SO_2 emissions (lb/MMBtu)	4.7×10^{-3}	4.7×10^{-3}	5.0×10^{-3}	4.8×10^{-3}
Permit Limit (lb/MMBtu)	-	-	-	*0.15*
Hydrogen Chloride				
HCl conc. (ug)	2,297	2,204	1,957	2,153
HCl emissions (lb/hr)	0.24	0.24	0.22	0.23
Permit Limit (lb/hr)	-	-	-	*0.60*

1. Each turbine's allowable NOx emission concentration is dependent on fuel sample variables. Calculations are presented in Appendix 4.

Table 6.4 Measured exhaust gas conditions and air pollutant emission rates for Turbine No. 4 (EUTURBINE4), Continued

Test No. Test date Test period (24-hr clock)	1 10/19/2023 1202-1232, 1236-1306	2 10/19/2023 1337-1437	3 10/19/2023 1458-1558	Three Test Average
Fuel flowrate (scfm)	2,202	2,187	2,165	2,185
Turbine output (kW)	4,776	4,782	4,744	4,767
Turbine output (MW)	4.78	4.78	4.74	4.77
LFG methane content (%)	50.9	-	-	50.9
Duct burner fuel use (scfm)	0.0	0.0	0.0	0.0
Turbine Heat Input (MMBtu/hr)	62.9	62.5	61.8	62.4
Exhaust Gas Composition				
CO_2 content (% vol)	5.44	5.50	5.42	5.45
O_2 content (% vol)	15.5	15.5	15.5	15.5
Moisture (% vol)	7.20	7.14	6.49	6.94
Exhaust gas flowrate (scfm)	38,052	37,703	37,855	37,870
Exhaust gas flowrate (dscfm)	35,313	35,011	35,399	35,241
Exhaust gas temperature (°F)	944	931	935	937
Formaldehyde				
HCOH conc. (ppmv)	1.12	1.08	1.13	1.11
HCOH emissions (lb/hr)	0.20	0.19	0.20	0.10
HCOH emissions (lb/MMBtu)	3.2×10^{-3}	3.0×10^{-3}	3.2×10^{-3}	3.1×10^{-3}
Permit Limit (lb/MMBtu)	-	-	-	*1.072*
Volatile Organic Compounds				
VOC conc. (ppmv)	0.31	0.16	0.06	0.18
VOC emissions (lb/hr)[2]	0.28	0.23	0.21	0.24
Permit Limit (lb/hr)	-	-	-	*0.8*

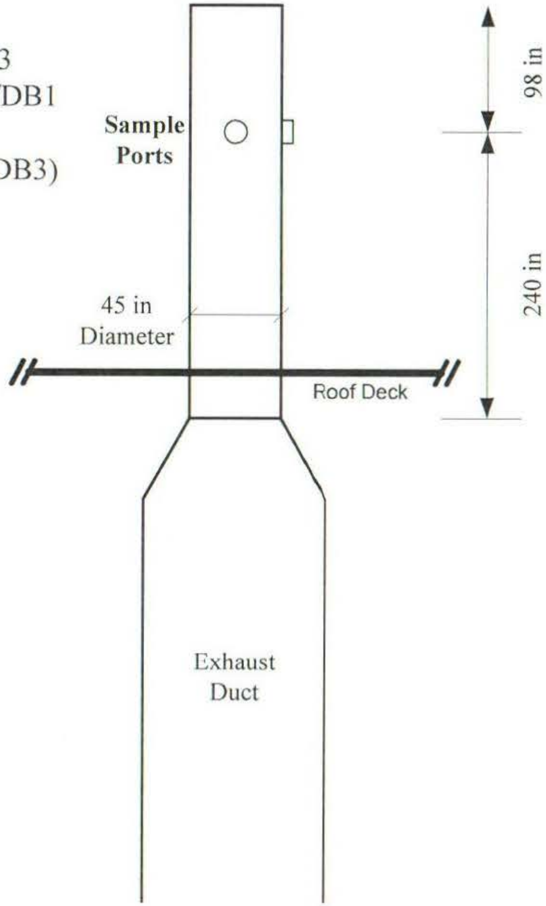
2. VOC emission rate includes formaldehyde.

3.

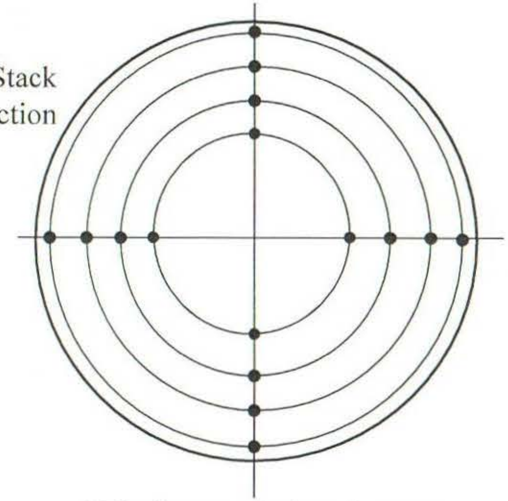
APPENDIX 1

- Turbine Sample Port Diagrams

Turbines 1-3
(EUTURBINE/DB1
through
EUTURBINE/DB3)



Exhaust Stack
Cross-Section

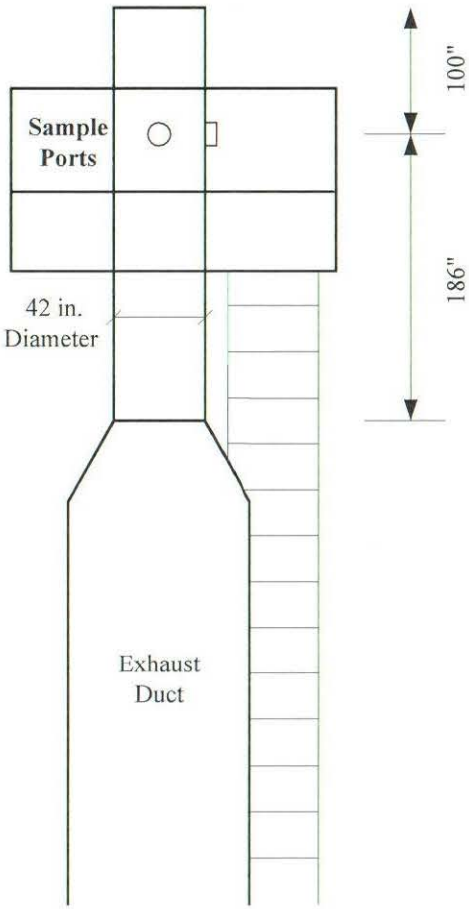


Velocity sample locations as
measured from stack wall
(not including 9.5" sampling port nipple)

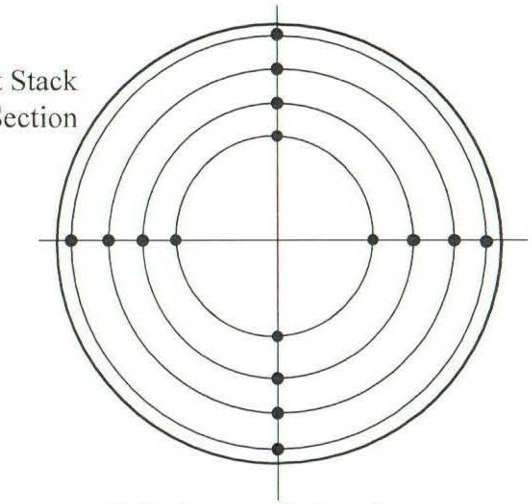
Pt. #	in.
1	1.44
2	4.73
3	8.73
4	14.49
5	30.47
6	36.27
7	40.28
8	43.56

11/14/23	**Arbor Hills Energy** **Exhaust Sampling Location – Turbine #1-3**		
	Scale None	Sheet 1 of 1	Impact Compliance & Testing

Turbine 4
(EUTURBINE4-S3)



Exhaust Stack
Cross-Section



Velocity sample locations as measured from stack wall (not including 6" sampling port nipple)

Pt. #	in.
1	1.34
2	4.41
3	8.15
4	13.52
5	28.43
6	33.85
7	37.59
8	40.66

7/20/18	**Arbor Hills Energy** **Exhaust Sampling Location – Turbine #4**		
	Scale None	Sheet 1 of 1	IMPACT COMPLIANCE & TESTING