Derenzo Environmental Services
Consulting and Testing

AIR EMISSION TEST REPORT

Title	AIR EMISSION TEST REPORT FOR THE VERIFICATION OF AIR POLLUTANT EMISSIONS FROM A LANDFILL GAS FUELED TURBINES
Report Date	November 8, 2018
Test Dates	October 16-19, 2018

Facility Information	
Name	Arbor Hills Energy, LLC
Street Address	1611 W. Five Mile Road
City, County	Northville, Oakland
SRN	N2688

Facility Permit Information	
Permit No.	MI-ROP-N2688-2011a
Emission Units	FGTURBINES-S3 (EGT Typhoon) FGDUCTBURNERS-S3 EUTURBINE4-S3 (Solar Taurus)

Testing Contractor	
Company	Derenzo Environmental Services
Mailing Address	39395 Schoolcraft Road Livonia, MI 48150
Phone	(734) 464-3880
Project No.	1807015

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

ARBOR HILLS ENERGY, LLC

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, Oakland County, Michigan. The turbines are fueled with landfill gas (LFG) that is collected from the Arbor Hills Landfill.

The three (3) EGT Typhoon turbines are combined cycle units equipped with heat recovery steam generators (HRSG) and duct burners to provide additional heat input. These emission units are identified as EUTURBINE1-S3 through EUTURBINE3-S3 and EUDUCTBURNER1-S3 through EUDUCTBURNER3-S3 in Section 3 of Renewable Operating (RO) Permit MI-ROP-N2688-2011a issued by the Michigan Department of Environmental Quality-Air Quality Division (MDEQ-AQD). The Solar Taurus is a simple cycle turbine identified as EUTURBINE4-S3 (i.e., it is not equipped with HRSG).

The conditions of RO Permit No. MI-ROP-N2688-2011a specify that for:

1. FGTURBINES-S3 and FGDUCTBURNERS-S3, verification of the emission rates for nitrogen oxides (NO_X), sulfur dioxide (SO_2), carbon monoxide (CO), hydrogen chloride (HCl), and volatile organic compounds (VOC) is required, by testing, every 20 calendar quarters.

2. EUTURBINE4-S3, verification of the emission rates for NO_X and SO_2 is required, by testing, annually.

The compliance test results presented in this report are for testing that was performed on October 16-19, 2018. This test event was a follow-up to testing that was performed earlier this year (May 29 through June 1, 2018). The exhaust gas sampling and analysis was performed using procedures specified in the Test Plan dated March 27, 2018. A notification was submitted August 29, 2018 for the October test event.

Questions regarding this emission test report should be directed to:

Test Methods and Procedures	Tyler J. Wilson Livonia Office Supervisor Derenzo Environmental Services 39395 Schoolcraft Road Livonia, MI 48150 (734) 464-3880 / twilson@derenzo.com
Facility Compliance Manager	Andrew Zalenski Environmental Manager Fortistar Methane Group 5087 Junction Road Lockport, NY 14094 (716) 439-1004 ext. 118 / azalenski@fortistar.com
Responsible Official	Anthony Falbo Vice President, Operations

Report Certification

This test report was prepared by Derenzo Environmental Services (DES) based on field sampling data collected by DES personnel Tyler Wilson, Brad Thome, Kevin Anderson, and Blake Beddow. Facility process data were collected and provided by Arbor Hills Energy employees or representatives.

A ROP Report Certification Form signed by the facility's Responsible Official accompanies this report.

I certify that the testing was conducted in accordance with the specified test methods and submitted test plan unless otherwise specified in this report. I believe the information provided in this report and its attachments are true, accurate, and complete.

Report Prepared By:	Reviewed By:
Tyler J. Wilson Livonia Office Supervisor Derenzo Environmental Services	Robert L. Harvey, P.E. General Manager Derenzo Environmental Services

2.0 SUMMARY OF TEST RESULTS AND OPERATING CONDITIONS

2.1 Purpose and Objective of the Tests

Stack testing was performed for three (3) EGT Typhoon combined cycle turbines (units equipped with duct burners and HRSG). These emission units must demonstrate compliance with the CO, NO_X, VOC, SO_2, and HCl permit emission limits specified in the Renewable Operating Permit MI-ROP-N2688-2011. Testing was also performed to measure NOx and SO_2 emissions for one Solar Taurus turbine that is identified as EUTURBINE4-S3.

The facility is required to perform testing on FGTURBINES-S3 and FGDUCTBURNERS-S3 every 20 calendar quarters. Annual testing is required for EUTURBINE4-S3.

The compliance test results presented in this report are for testing that was performed on October 16-19, 2018. This test event was a retest following a test event performed earlier this year on May 29 through June 1, 2018.

2.2 Operating Conditions During the Compliance Tests

Testing was performed while the units were operated at normal, maximum levels during the test periods. During the test events, the electricity generators connected to the three (3) EGT Typhoon gas combustion turbines produced between 3.4 and 3.8 MW each. The electricity generator connected to the Solar Taurus gas combustion turbine produced about 5.1 MW.

Fuel flowrate (cubic feet per minute), fuel methane content (%), and power production (MW) were recorded at 15-minute intervals for each test period. For tests that included duct burner operation, fuel flowrate to the duct burner (cubic feet per minute) and steam turbine power production (MW) were recorded.

Appendix 2 provides operating records provided by Arbor Hills Energy representatives for the test periods.

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

Table 2.1 Average engine operating conditions during the test periods

Device	Power Production (MW)	Fuel Flowrate (scfm)	Methane Content (%)	Fuel Flowrate to Duct Burner (scfm)	Power Prod. Steam Turbine (scfm)
#1 / Typhoon	3.66	1,710	47.9	--	--
#2 / Typhoon	3.55	1,807	47.4	--	--
#3 / Typhoon	3.76	1,880	45.8	--	--
#1 / Typhoon DB*	3.43	1,592	49.2	402	4.27
#2 / Typhoon DB*	3.48	1,803	47.1	376	4.81
#3 / Typhoon DB*	3.40	1,744	47.0	377	4.75
#4 / Taurus	5.05	2,192	48.3	--	--

*DB denotes duct burner operation.

2.3 Summary of Air Pollutant Sampling Results

The gas exhausted from each turbine, or the combined turbine/duct burner exhaust gas, was sampled for three (3) one-hour test periods during the compliance testing performed October 16-19, 2018.

Table 2.2 presents a summary of emission rates for FGTURBINES-S3 and FGDUCTBURNERS-S3 compared to allowable emission rates.

Table 2.3 presents a summary of results for EUTURBINE4-S3.

Test data presented in Tables 2.2 and 2.3 are the three-test average for each unit and operating mode. Annual ton per year (ton/yr) values are based on continuous operation (8,760 hr/yr) at the measured lb/hr emission rate. Actual ton/yr values will be reported by facility based on actual operating time.

The test results demonstrate compliance with the emission rates specified in MI-ROP-N2688-2011a for all regulated air pollutants with the exception of SO_2. Measured SO_2 emission rates exceeded the pounds per hour (lb/hr) rate specified in MI-ROP-N2688-2011a for each of the four turbines and the three duct burners. Measured NO_X emissions (TPY) for Turbine No. 3 would exceed the allowable annual emission rate specified in MI-ROP-N2688-2011a if it operated continuously throughout the calendar year (8,760 hr/yr). At the measured NO_X emission rate, annual Turbine No. 3 NO_X emissions would be less than the permitted TPY emission limit if it operates approximately 90% of the calendar year.

Test results for each one hour sampling period are presented in Section 6.0 of this report.

Table 2.2 Summary of FGTURBINES-S3 and FGDUCTBURNERS-S3 emission rates compared to allowable emission rates

	Turbine 1	Turbine 2	Turbine 3	*Permit Limit*
Turbine Only Mode				
CO Emission Rate (lb/hr)	2.79	8.81	3.52	*13.1*
CO Emission Rate (ton/yr)	12.2	38.6	15.4	*57.2*
NOx Emission Rate (lb/hr)	5.63	6.95	8.28	*8.8*
NOx Emission Rate (ton/yr)	24.7	30.5	36.3	*33.0*
VOC Emission Rate (lb/hr)	0.05	0.11	0.04	*2.4*
VOC Emission Rate (ton/yr)	0.20	0.49	0.15	*10.4*
SO_2 Emission Rate (lb/hr)	4.46	6.32	7.56	*2.9*
SO_2 Emission Rate (ton/yr)	19.5	27.7	33.1	*12.5*
HCl Emission Rate (lb/hr)	0.16	0.22	0.27	*1.9*
HCl Emission Rate (ton/yr)	0.70	0.95	1.20	*8.2*
Calculated Duct Burner				
CO Emission Rate (lb/hr)	0.87	<0.1	<0.1	*2.2*
CO Emission Rate (ton/yr)	3.81	<0.1	<0.1	*9.7*
NOx Emission Rate (lb/hr)	0.30	0.25	0.38	*1.6*
NOx Emission Rate (ton/yr)	1.32	1.11	1.65	*7.1*
VOC Emission Rate (lb/hr)	0.02	<0.1	0.00	*0.9*
VOC Emission Rate (ton/yr)	0.10	<0.1	<0.1	*4.0*
SO_2 Emission Rate (lb/hr)	1.87	1.63	1.84	*0.3*
SO_2 Emission Rate (ton/yr)	8.17	7.15	8.05	*1.5*
HCl Emission Rate (lb/hr)	0.05	0.04	0.12	*0.8*
HCl Emission Rate (ton/yr)	0.21	0.16	0.53	*3.3*

Table 2.3 Summary of EUTURBINE4-S3 emission rates compared to allowable emission rates

Emission Parameter		Turbine No. 4 Emissions	Permit Limit
NOx	NO_X emissions (lb/hr)	7.42	9.02
	NO_X emissions (ton/yr)	32.5	39.5
SO_2	SO_2 emissions (lb/MWhr)	1.45	0.9

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

The three (3) EGT Typhoon turbines typically produce 3.2 to 3.7 Megawatts (MW) of electricity each, while the Solar Taurus turbine can produce up to 4.9 MW. The three EGT Typhoon turbines are equipped with HRSG units that supply steam to steam turbines for additional electricity generation.

The four turbines and HRSG supplemental heat duct burners are fueled exclusively with LFG recovered from the adjacent Landfill, transferred to Arbor Hills Energy, and treated (compressed, dewatered and filtered) prior to its use as fuel. The fuel (treated LFG) consumption rate for each turbine 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).

The turbines are not equipped with add-on emission control equipment. NO_X emissions are suppressed by the use of dry low-NO_X combustors and CO emissions are limited by proper operation of the combustion units to completely combust (oxidize) the methane and other hydrocarbons in the treated LFG fuel.

3.3 Sampling Locations

The turbine and duct burner exhaust gas is released to the atmosphere through dedicated vertical exhaust stacks with vertical release points.

The exhaust stack sampling ports for EUTURBINE1-S3 through EUTURBINE3-S3 (which includes the exhaust from the associated duct burners) are identical. The stack sampling location has an inner diameter of 48 inches and is equipped with two (2) sample ports, opposed 90°, that provide a sampling location greater than 8 feet (2 duct diameters) upstream and greater than 20 feet (5 duct diameters) downstream from any flow disturbance and satisfies the USEPA Method 1 criteria for a representative sample location.

The sampling ports for EUTURBINE4-S3 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.

Appendix 1 provides a diagram of the emission test sampling locations.

4.0 SAMPLING AND ANALYTICAL PROCEDURES

A test protocol for the air emission testing was reviewed and approved by the MDEQ-AQD. This section provides a summary of the sampling and analytical procedures that were used during the Arbor Hills Energy 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 zirconia ion/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 6C	SO_2 by pulsed ultraviolet florescence instrument analyzer
USEPA Method 7E	Exhaust gas NOx concentration was determined using chemiluminescence instrumental analyzers.
USEPA Method 10	Exhaust gas CO concentration was measured using an NDIR instrumental analyzer
USEPA Method 25A	Measurement of total hydrocarbon (THC) concentrations
USEPA Method 26A	Exhaust gas HCl concentration by single point (non-isokinetic) sampling and analysis by ion chromatography
ASTM Method D-5504	Fuel gas sulfur analysis by gas chromatography and chemiluminescence

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.

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 single beam single wavelength (SBSW) infrared gas analyzer. The O_2 content of the exhaust was monitored using a 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 Content (USEPA Method 4)

Moisture content of the turbine exhaust gas was determined in accordance with USEPA Method 4 using a chilled impinger sampling train. For the turbines in which HCl sampling was performed, moisture content was measured as part of the USEPA sampling procedures for HCl (i.e., not as a separate measurement train), which was performed concurrently with the instrumental analyzer test periods. During each sampling period, a gas sample was extracted from the source where moisture was removed from the sampled gas stream using impingers that were submersed in an ice bath. At the conclusion of each sampling period, the moisture gain in the impingers was determined gravimetrically by weighing each impinger to determine net weight gain.

4.5 Sulfur Dioxide by Instrumental Analyzer (USEPA Method 6C)

Turbine exhaust gas SO_2 concentration measurements was performed using a Thermo Environmental Instruments, Inc. (TEI) Model 43i that uses pulsed ultraviolet fluorescence technology in accordance with USEPA Method 6C for the measurement of SO_2 concentration.

Appendix 4 provides SO_2 calculation sheets. Raw instrument response data are provided in Appendix 5.

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

NO_X and CO pollutant concentrations in the turbine exhaust gas stream were determined using a chemiluminescence NO_X analyzer and an infrared 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 NOx calculation sheets. Raw instrument response data are provided in Appendix 5.

4.7 Measurement of Total Hydrocarbon (THC) Concentration (USEPA Method 25A)

USEPA Method 25A, *Determination of Total Gaseous Organic Concentration Using A Flame Ionization Detector*, was used to determine the total hydrocarbon (THC) concentration, relative to a propane standard, for the turbine exhaust measurement locations. The measured THC concentration was used with the measured volumetric air flowrate to calculate a THC mass flow rate (pounds per hour as propane) for each test period.

Throughout each test period, a sample of the gas from the measurement location was delivered to a TEI Model 51c Total Hydrocarbon Flame Ionization Analyzer (FIA) using an extractive gas sampling system and heated Teflon® sample line equipped with a heating element and temperature controller to maintain the temperature of the sample line at 250°F or above. The sampled gas stream was not be dried prior to being introduced to the FIA instrument; therefore, THC concentration measurements correspond to standard conditions with no moisture correction.

Appendix 4 provides THC calculation sheets. Raw instrument response data are provided in Appendix 5.

4.8 Hydrogen Chloride Emission Sampling (UESPA Method 26A)

HCl concentration in the turbine or combined turbine/duct burner exhaust gas was determined using USEPA Method 26A. An integrated sample of the exhaust gas was withdrawn at a constant rate (i.e., non-isokinetic rate) through chilled impingers containing 0.1 normal sulfuric acid (0.1N H_2SO_4). All sample train components in contact with the gas stream were constructed of glass, except for the probe union, which was silonite-coated stainless steel.

At the end of the one-hour test period, the impinger solutions were recovered and picked up by a third-party laboratory (Enthalpy Analytical in Wilmington, NC) for chlorine analysis by ion specific electrode analysis in accordance with USEPA Method 26A.

Appendix 1 provides a diagram of the HCl sampling train. Appendix 4 provides HCl emission rate calculations. Appendix 7 provides a copy of the laboratory analytical report.

4.9 Fuel Gas Analysis for Sulfur (ASTM Method D-5504)

In addition to the exhaust gas SO_2 concentration measurements, samples of the treated LFG used as fuel were analyzed for sulfur content and SO_2 emission calculations were performed based on the conversion of sulfur to SO_2. A representative sample of the treated LFG was collected on two (2) days of the test event (October 17 and 18, 2018) using evacuated, inert (silonite-coated) stainless steel canisters. The sample Teflon tubing was connected to the fuel header at a location after the treatment system and gas blower. Sample canister vacuum was recorded before and after sampling and verified by the laboratory upon receipt.

The gas samples were analyzed by ALS Analytical (Simi Valley, CA) for sulfur bearing compounds by ASTM D-5504.

In addition, the MDEQ-AQD requested that inlet LFG be sampled for hydrogen sulfide (H_2S) concentration once each day of the test event using Draeger® tubes

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

5.0 QA/QC ACTIVITIES

5.1 Exhaust Gas Flow

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

The Pitot tube and connective tubing were leak-checked periodically throughout the test event to verify the integrity of the measurement system.

The absence of significant cyclonic flow for the exhaust configurations were 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).

5.2 NO_x Converter Efficiency Test

The NO_2 – NO conversion efficiency of the chemiluminescence NOx 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_x concentration is at least 90% of the expected value.

The NO_2 – NO conversion efficiency test satisfied the USEPA Method 7E criteria (measured NOx concentration was greater than 90% of the expected value as required by Method 7E).

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 NOx, CO, SO_2, 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 NOx, CO, SO_2, 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.

The instruments were calibrated with USEPA Protocol 1 certified concentrations of CO_2, O_2, NOx, SO_2, and CO in nitrogen and zeroed using hydrocarbon free nitrogen. 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 the exhaust stacks. The stainless steel sample probe was positioned at sample points correlating to 16.7, 50.0 (centroid) and 83.3% of the stack diameter. Pollutant concentration data were recorded at each sample point for a minimum of twice the maximum system response time. For all four (4) turbine exhaust stacks each sample point had less than 5% variation from the mean, therefore, the turbine exhaust stacks were determined to be unstratified. A single point was used for instrument sampling.

5.7 Meter Box Calibrations and Isokinetic Sampling

The dry gas meter sampling console, which was used for HCl 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 console was calibrated using a NIST traceable Omega® Model CL 23A temperature calibrator.

5.8 HCl Recovery and Analysis

All recovered Method 26A impinger solutions and rinses were stored in appropriate HDPE bottles with Teflon® lined caps. The liquid level on each bottle was marked with a permanent marker prior to shipment and the caps were secured closed with tape. A blank solution was prepared using 0.1 N H_2SO_4 and the high-purity water used for recovery and analyzed by the laboratory with the sample train solutions. QA/QC procedures used by the laboratory are included in the final report provided by Enthalpy.

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, Pitot tube, scale, and barometer calibration records).

6.0 RESULTS

6.1 Turbine Exhaust Test Results and Allowable Emission Limits

Turbine operating data and air pollutant emission measurement results for each one-hour test period are presented in Tables 6.1 through 6.8.

Hourly (lb/hr) emission rates are compared to the allowable lb/hr (pph) limit specified in the RO Permit. Maximum annual (ton/yr) emissions presented in Tables 6.1 through 6.8 are calculated based on continuous operation (8,760 hours/yr) at the measured lb/hr emission rate. However, it should be noted that actual annual emissions will be calculated by the facility based on actual process operating hours.

The measured air pollutant emission rates for FGTURBINES-S3 are less than the allowable limits for all pollutants, except for SO_2, as specified in the RO Permit:

- 8.8 pounds per hour (pph) and 33.0 tons per year (tpy) NOx;
- 13.1 pph and 57.2 tpy CO;
- 2.9 pph and 12.5 tpy SO_2;
- 1.9 pph and 8.2 tpy HCl;
- 2.4 pph and 10.4 tpy VOC.

Duct burner emissions were calculated by subtracting the 'turbine only' emission rate from the emission rate measured when the turbine and duct burner were operating in combination.

The RO Permit specifies the following air pollutant emission limits for each duct burner in FGDUCTBURNERS-S3:

- 1.6 pph and 7.1 tpy NOx;
- 2.2 pph and 9.7 tpy CO;
- 0.3 pph and 1.5 tpy SO_2;
- 0.8 pph and 3.3 tpy HCl;
- 0.9 pph and 4.0 tpy VOC.

The measured air pollutant emission rates for EUTURBINE4-S3, are less than the allowable limits specified in Section 3 of RO Permit No. MI-ROP-N2688-2011a, except for SO_2,:

- 9.02 pph and 39.5 tpy NOx;
- 0.9 pounds per megawatt-hour (lb/MWhr) or 0.15 pounds per million British Thermal Unit (lb/MMBtu) SO_2.

6.2 Results of LFG Fuel Sulfur Content Analyses

The treated LFG used as fuel for the Arbor Hills Energy facility was sampled on:

- Two days of the test event (October 17 and 18, 2018) using vacuum canisters and sent to a third-party laboratory for analysis of sulfur-bearing compounds.
- All four days of the test event using Draeger® tubes.

The laboratory reported an H_2S content of 350 and 360 ppmv for the two (2) canister samples. The calculated total reduced sulfur (TRS) for the samples was 377 and 371 ppmv, respectively. The Draeger® tube results for the four (4) samples ranged from approximately 220 to 340 ppm H_2S.

6.3 Variations from Normal Sampling Procedures or Operating Conditions

The testing for all pollutants was performed in accordance with USEPA methods, the test protocol dated March 27, 2018, and the retest notification dated August 29, 2018. The turbines were operated at maximum achievable load during the test periods.

Exhaust gas HCl sampling was performed at a constant sample rate at a single point in each exhaust stack (i.e., not using isokinetic procedures). Tom Gasloli of MDEQ-AQD approved this method prior to the test event pending a stratification check on the exhaust stacks verifying that the stacks were not stratified. During Test No. 1 for all four (4) turbines (HCl sampling was only performed for Turbine Nos. 1-3), O_2 and CO_2 were measured at three (3) points throughout the stack for at least twice the system response time. The response for O_2 and CO_2 for all turbine stacks differed by no more than 5% from the three (2) point average, so HCl was measured at one point (centroid).

Table 6.1 Measured exhaust gas conditions and pollutant emission rates
Turbine No. 1 (Turbine only mode)

Test No. Test date Test period (24-hr clock)	1 10/16/18 0820-0920	2 10/16/18 0955-1055	3 10/16/18 1123-1223	Three Test Average
Fuel flowrate (scfm)	1,773	1,697	1,660	1,710
Generator output (MW)	3.80	3.62	3.55	3.66
LFG methane content (%)	47.4	47.9	48.5	47.9
Exhaust O_2 Content (%)	15.0	15.1	15.2	15.1
Exhaust CO_2 Content (%)	5.31	5.26	5.23	5.27
Exhaust Moisture Content (%)	6.16	6.16	5.12	5.82
Exhaust Temperature (°F)	510	514	512	512
Exhaust Flowrate (scfm)	23,721	23,895	23,921	23,846
Exhaust Flowrate (dscfm)	22,259	22,422	22,695	22,459
CO Concentration (ppmvd)	32.7	28.5	24.2	28.5
CO Emission Rate (lb/hr)	3.18	2.79	2.39	2.79
CO Emission Rate (ton/yr)	13.9	12.2	10.5	12.2
NOx Concentration (ppmvd)	34.2	34.9	35.8	35.0
NOx Emission Rate (lb/hr)	5.46	5.62	5.83	5.63
NOx Emission Rate (ton/yr)	23.9	24.6	25.5	24.7
VOC Concentration (ppmvd)	0.43	0.22	0.17	0.28
VOC Emission Rate (lb/hr)	0.07	0.04	0.03	0.05
VOC Emission Rate (ton/yr)	0.31	0.16	0.12	0.20
SO_2 Concentration (ppmvd)	18.3	20.7	20.7	19.9
SO_2 Emission Rate (lb/hr)	4.06	4.64	4.69	4.46
SO_2 Emission Rate (ton/yr)	17.8	20.3	20.5	19.5
HCl Weight (µg)	2,325	2,311	2,312	2,316
DGM Sample Volume (ft^3)	45.0	44.6	44.5	44.7
HCl Emission Rate (lb/hr)	0.16	0.16	0.16	0.16
HCl Emission Rate (ton/yr)	0.68	0.70	0.72	0.70

Table 6.2 Measured exhaust gas conditions and pollutant emission rates
Turbine No. 1 with Duct Burner operation

Test No. Test date Test period (24-hr clock)	1 10/16/18 1255-1355	2 10/16/18 1427-1527	3 10/16/18 1556-1656	Three Test Average
Fuel flowrate (scfm)	1,625	1,597	1,592	1,605
Generator output (MW)	3.46	3.42	3.40	3.43
LFG methane content (%)	48.8	49.3	49.6	49.2
Steam Turbine Output (MW)	4.33	4.25	4.24	4.27
Duct Burner Fuel Use (scfm)	402	401	403	402
Exhaust O_2 Content (%)	13.5	13.5	13.5	13.5
Exhaust CO_2 Content (%)	6.74	6.73	6.75	6.74
Exhaust Moisture Content (%)	7.36	7.43	7.22	7.34
Exhaust Temperature (°F)	558	558	560	558
Exhaust Flowrate (scfm)	23,106	24,337	22,881	23,441
Exhaust Flowrate (dscfm)	21,404	22,530	21,229	21,721
CO Concentration (ppmvd)	38.4	38.6	38.7	38.6
CO Emission Rate (lb/hr)	3.59	3.80	3.58	3.66
CO Emission Rate (ton/yr)	15.7	16.6	15.7	16.0
NOx Concentration (ppmvd)	37.6	37.9	38.8	38.1
NOx Emission Rate (lb/hr)	5.77	6.12	5.91	5.94
NOx Emission Rate (ton/yr)	25.3	26.8	25.9	26.0
VOC Concentration (ppmvd)	0.46	0.41	0.39	0.42
VOC Emission Rate (lb/hr)	0.07	0.07	0.06	0.07
VOC Emission Rate (ton/yr)	0.32	0.30	0.27	0.30
SO_2 Concentration (ppmvd)	28.0	29.8	29.7	29.2
SO_2 Emission Rate (lb/hr)	5.99	6.69	6.30	6.33
SO_2 Emission Rate (ton/yr)	26.2	29.3	27.6	27.7
HCl Weight (µg)	2,325	2,311	2,312	2,316
DGM Sample Volume (ft^3)	45.0	44.6	44.5	44.7
HCl Emission Rate (lb/hr)	0.21	0.21	0.20	0.21
HCl Emission Rate (ton/yr)	0.91	0.93	0.88	0.91

Table 6.3 Measured exhaust gas conditions and pollutant emission rates
Turbine No. 2 (Turbine only mode)

Test No. Test date Test period (24-hr clock)	1 10/17/18 0736-0836	2 10/17/18 0902-1002	3 10/17/18 1025-1125	Three Test Average
Fuel flowrate (scfm)	1,813	1,807	1,801	1,807
Generator output (MW)	3.59	3.55	3.50	3.55
LFG methane content (%)	47.7	47.3	47.2	47.4
Exhaust O_2 Content (%)	14.9	15.0	15.0	15.0
Exhaust CO_2 Content (%)	5.44	5.43	5.40	5.42
Exhaust Moisture Content (%)	6.36	6.30	6.15	6.27
Exhaust Temperature (°F)	485	483	484	484
Exhaust Flowrate (scfm)	31,926	31,884	31,395	31,735
Exhaust Flowrate (dscfm)	29,897	29,875	29,465	29,745
CO Concentration (ppmvd)	69.4	68.1	65.9	67.8
CO Emission Rate (lb/hr)	9.06	8.89	8.48	8.81
CO Emission Rate (ton/yr)	39.7	38.9	37.1	38.6
NOx Concentration (ppmvd)	32.2	32.4	33.2	32.6
NOx Emission Rate (lb/hr)	6.91	6.94	7.01	6.95
NOx Emission Rate (ton/yr)	30.2	30.4	30.7	30.5
VOC Concentration (ppmvd)	0.53	0.53	0.47	0.51
VOC Emission Rate (lb/hr)	0.12	0.12	0.10	0.11
VOC Emission Rate (ton/yr)	0.51	0.51	0.45	0.49
SO_2 Concentration (ppmvd)	19.5	21.5	22.8	21.3
SO_2 Emission Rate (lb/hr)	5.83	6.42	6.70	6.32
SO_2 Emission Rate (ton/yr)	25.5	28.1	29.4	27.7
HCl Weight (µg)	2,412	2,357	2,261	2,343
DGM Sample Volume (ft^3)	44.7	44.7	44.0	44.4
HCl Emission Rate (lb/hr)	0.22	0.22	0.21	0.22
HCl Emission Rate (ton/yr)	0.97	0.96	0.93	0.95

Table 6.4 Measured exhaust gas conditions and pollutant emission rates
Turbine No. 2 with Duct Burner operation

Test No. Test date Test period (24-hr clock)	1 10/17/18 1200-1300	2 10/17/18 1321-1421	3 10/17/18 1444-1544	Three Test Average
Fuel flowrate (scfm)	1,802	1,802	1,804	1,803
Generator output (MW)	3.48	3.48	3.47	3.48
LFG methane content (%)	47.0	47.2	47.1	47.1
Steam Turbine Output (MW)	4.84	4.84	4.77	4.81
Duct Burner Fuel Use (scfm)	375	376	376	376
Exhaust O_2 Content (%)	13.8	13.8	13.8	13.8
Exhaust CO_2 Content (%)	6.50	6.49	6.48	6.49
Exhaust Moisture Content (%)	6.76	7.19	7.22	7.06
Exhaust Temperature (°F)	496	487	493	492
Exhaust Flowrate (scfm)	31,739	31,921	31,799	31,820
Exhaust Flowrate (dscfm)	29,593	29,626	29,504	29,574
CO Concentration (ppmvd)	65.1	64.7	64.5	64.8
CO Emission Rate (lb/hr)	8.41	8.36	8.31	8.36
CO Emission Rate (ton/yr)	36.8	36.6	36.4	36.6
NOx Concentration (ppmvd)	34.4	33.6	34.0	34.0
NOx Emission Rate (lb/hr)	7.30	7.13	7.19	7.21
NOx Emission Rate (ton/yr)	32.0	31.2	31.5	31.6
VOC Concentration (ppmvd)	0.41	0.34	0.24	0.33
VOC Emission Rate (lb/hr)	0.09	0.07	0.05	0.07
VOC Emission Rate (ton/yr)	0.39	0.33	0.23	0.32
SO_2 Concentration (ppmvd)	25.5	27.5	27.8	26.9
SO_2 Emission Rate (lb/hr)	7.53	8.12	8.19	7.95
SO_2 Emission Rate (ton/yr)	33.0	35.6	35.9	34.8
HCl Weight (µg)	2,734	2,635	2,792	2,720
DGM Sample Volume (ft^3)	44.3	44.0	44.4	44.2
HCl Emission Rate (lb/hr)	0.26	0.25	0.26	0.25
HCl Emission Rate (ton/yr)	1.12	1.09	1.14	1.12

Table 6.5 Measured exhaust gas conditions and pollutant emission rates
Turbine No. 3 (Turbine only mode)

Test No. Test date Test period (24-hr clock)	1 10/18/18 0730-0830	2 10/18/18 0853-0953	3 10/18/18 1014-1114	Three Test Average
Fuel flowrate (scfm)	1,935	1,863	1,841	1,880
Generator output (MW)	3.93	3.74	3.61	3.76
LFG methane content (%)	45.8	45.9	45.8	45.8
Exhaust O_2 Content (%)	15.0	15.2	15.2	15.1
Exhaust CO_2 Content (%)	5.35	5.23	5.20	5.26
Exhaust Moisture Content (%)	5.64	4.51	6.00	5.38
Exhaust Temperature (°F)	508	506	500	504
Exhaust Flowrate (scfm)	35,141	34,771	34,774	34,895
Exhaust Flowrate (dscfm)	33,160	33,201	32,689	33,017
CO Concentration (ppmvd)	24.8	24.6	23.7	24.4
CO Emission Rate (lb/hr)	3.59	3.57	3.39	3.52
CO Emission Rate (ton/yr)	15.7	15.6	14.8	15.4
NOx Concentration (ppmvd)	34.9	35.0	35.0	35.0
NOx Emission Rate (lb/hr)	8.30	8.34	8.19	8.28
NOx Emission Rate (ton/yr)	36.4	36.5	35.9	36.3
VOC Concentration (ppmvd)	0.17	0.12	0.15	0.15
VOC Emission Rate (lb/hr)	0.04	0.03	0.04	0.04
VOC Emission Rate (ton/yr)	0.18	0.13	0.16	0.15
SO_2 Concentration (ppmvd)	22.5	22.8	23.4	22.9
SO_2 Emission Rate (lb/hr)	7.46	7.56	7.65	7.56
SO_2 Emission Rate (ton/yr)	32.7	33.1	33.5	33.1
HCl Weight (µg)	2,371	46.8	2,187	1,535
DGM Sample Volume (ft^3)	45.2	44.7	44.4	44.8
HCl Emission Rate (lb/hr)	0.24	0.00	0.22	0.15
HCl Emission Rate (ton/yr)	1.03	0.02	0.97	0.68

Table 6.6 Measured exhaust gas conditions and pollutant emission rates
Turbine No. 3 with Duct Burner operation

Test No. Test date Test period (24-hr clock)	1 10/18/18 1140-1240	2 10/18/18 1302-1402	3 10/18/18 1424-1524	Three Test Average
Fuel flowrate (scfm)	1,774	1,749	1,711	1,744
Generator output (MW)	3.44	3.40	3.35	3.40
LFG methane content (%)	46.5	47.0	47.6	47.0
Steam Turbine Output (MW)	4.59	4.80	4.86	4.75
Duct Burner Fuel Use (scfm)	382	386	364	377
Exhaust O_2 Content (%)	13.7	13.7	13.8	13.8
Exhaust CO_2 Content (%)	6.56	6.56	6.47	6.53
Exhaust Moisture Content (%)	7.10	6.93	6.73	6.92
Exhaust Temperature (°F)	534	532	527	531
Exhaust Flowrate (scfm)	34,775	33,857	33,958	34,197
Exhaust Flowrate (dscfm)	32,305	31,512	31,674	31,830
CO Concentration (ppmvd)	21.0	19.9	17.9	19.6
CO Emission Rate (lb/hr)	2.96	2.74	2.48	2.73
CO Emission Rate (ton/yr)	13.0	12.0	10.9	11.9
NOx Concentration (ppmvd)	37.5	37.9	38.4	37.9
NOx Emission Rate (lb/hr)	8.68	8.57	8.72	8.66
NOx Emission Rate (ton/yr)	38.0	37.5	38.2	37.9
VOC Concentration (ppmvd)	0.17	0.17	0.08	0.14
VOC Emission Rate (lb/hr)	0.04	0.04	0.02	0.03
VOC Emission Rate (ton/yr)	0.17	0.18	0.08	0.14
SO_2 Concentration (ppmvd)	30.0	29.6	29.2	29.6
SO_2 Emission Rate (lb/hr)	9.66	9.30	9.23	9.40
SO_2 Emission Rate (ton/yr)	42.3	40.7	40.4	41.2
HCl Weight (µg)	2,761	2,793	2,733	2,762
DGM Sample Volume (ft^3)	44.0	43.8	45.6	44.5
HCl Emission Rate (lb/hr)	0.28	0.28	0.26	0.27
HCl Emission Rate (ton/yr)	1.23	1.22	1.16	1.20

Table 6.7 Summary of FGTURBINES-S3 and FGDUCTBURNERS-S3 emission rates compared to allowable emission rates

	Turbine 1	Turbine 2	Turbine 3	*Permit Limit*
Combined Turbine / Duct Burner				
CO Emission Rate (lb/hr)	3.66	8.36	2.73	
NOx Emission Rate (lb/hr)	5.94	7.21	8.66	
VOC Emission Rate (lb/hr)	0.07	0.07	0.03	
SO_2 Emission Rate (lb/hr)	6.33	7.95	9.40	
HCl Emission Rate (lb/hr)	0.21	0.25	0.27	
Turbine Only Mode				
CO Emission Rate (lb/hr)	2.79	8.81	3.52	*13.1*
CO Emission Rate (ton/yr)	12.2	38.6	15.4	*57.2*
NOx Emission Rate (lb/hr)	5.63	6.95	8.28	*8.8*
NOx Emission Rate (ton/yr)	24.7	30.5	36.3	*33.0*
VOC Emission Rate (lb/hr)	0.05	0.11	0.04	*2.4*
VOC Emission Rate (ton/yr)	0.20	0.49	0.15	*10.4*
SO_2 Emission Rate (lb/hr)	4.46	6.32	7.56	*2.9*
SO_2 Emission Rate (ton/yr)	19.5	27.7	33.1	*12.5*
HCl Emission Rate (lb/hr)	0.16	0.22	0.15	*1.9*
HCl Emission Rate (ton/yr)	0.70	0.95	0.68	*8.2*
Calculated Duct Burner				
CO Emission Rate (lb/hr)	0.87	<0.1	<0.1	*2.2*
CO Emission Rate (ton/yr)	3.81	<0.1	<0.1	*9.7*
NOx Emission Rate (lb/hr)	0.30	0.25	0.38	*1.6*
NOx Emission Rate (ton/yr)	1.32	1.11	1.65	*7.1*
VOC Emission Rate (lb/hr)	0.02	<0.1	0.00	*0.9*
VOC Emission Rate (ton/yr)	0.10	<0.1	<0.1	*4.0*
SO_2 Emission Rate (lb/hr)	1.87	1.63	1.84	*0.3*
SO_2 Emission Rate (ton/yr)	8.17	7.15	8.05	*1.5*
HCl Emission Rate (lb/hr)	0.05	0.04	0.12	*0.8*
HCl Emission Rate (ton/yr)	0.21	0.16	0.53	*3.3*

Table 6.7 Notes

Test data presented in table is the three-test average. Ton/yr values are based on continuous operation (8,760 hr/yr) at the measured lb/hr emission rate. Actual ton/yr values will be reported by facility based on actual operating time.

Duct Burner emissions calculated by subtracting 'Turbine Only' emission rate from 'Combined Turbine / Duct Burner' emission rate. If subtraction results in a negative value, the emission rate is reported as <0.1.

Table 6.8 Measured exhaust gas conditions and pollutant emission rates
Turbine No. 4

Test No. Test date Test period (24-hr clock)	1 10/19/18 0745-0845	2 10/19/18 0908-1014	3 10/19/18 1035-1135	Three Test Average
Fuel flowrate (scfm)	2,232	2,214	2,132	2,192
Generator output (MW)	5.16	5.08	4.91	4.50
LFG methane content (%)	48.1	48.0	48.6	48.3
Exhaust O_2 Content (%)	15.2	15.2	15.2	15.2
Exhaust CO_2 Content (%)	5.22	5.20	5.19	5.20
Exhaust Moisture Content (%)	3.92	7.56	5.54	5.67
Exhaust Temperature (°F)	913	910	911	911
Exhaust Flowrate (scfm)	39,975	39,675	40,433	40,028
Exhaust Flowrate (dscfm)	38,406	36,674	38,194	37,758
NOx Concentration (ppmvd)	27.3	27.1	27.8	27.4
NOx Emission Rate (lb/hr)	7.51	7.13	7.61	7.42
NOx Permit Limit (lb/hr)	-	-	-	*9.02*
NOx Emission Rate (ton/yr)	32.9	31.2	33.3	32.5
NOx Permit Limit (ton/yr)	-	-	-	*39.5*
SO_2 Concentration (ppmvd)	17.4	17.8	23.0	19.4
SO_2 Emission Rate (lb/MWhr)	1.29	1.29	1.79	1.45
SO_2 Permit Limit (lb/MWhr)	-	-	-	*0.9*

Table 6.9 Summary of LFG fuel sulfur content analyses

Sample Date	10/16/18	10/17/18	10/18/18	10/19/19
Draeger® tube[1] (ppm H_2S)	340	320	310	220
Lab result (ppm H_2S)	--	350	360	--
Lab result[2] (ppm TRS)	--	377	371	--
SO_2 emission factor (lb/MMcf)	--	62.66	61.80	--
Turbine fuel use rate[3] (scfm)	--	1,801	1,841	--
Turbine SO_2 emissions[4] (lb/hr)	--	6.77	6.83	--

Table 6.9 Notes

1. Estimated from observation of Draeger® tubes. Photos are provided in Appendix 7.
2. TRS concentration based on the total of all sulfur-bearing compounds detected in the sample. See laboratory report in Appendix 7.
3. Samples were collected between 10:00 and 11:00 on each day. The fuel use rate recorded for that turbine test period was used for the calculation.
4. SO_2 emission rate calculated using the fuel use rate and emission factor derived from the laboratory analysis.