BTEC Inc.

Gas Turbine No. 10 and Cogeneration System Emissions Test Report

Prepared for:

The University of Michigan

Ann Arbor, Michigan

Central Power Plant
1120 East Huron Street
Ann Arbor, Michigan

BTEC Project No. 049AS-239748
May 16, 2018

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BT Environmental Consulting, Inc.
4949 Fernlee Aveune
Royal Oak, Michigan 48073
(248) 548-8070

BTEC Inc.

EXECUTIVE SUMMARY

BT Environmental Consulting, Inc. (BTEC) was retained by The University of Michigan (U-M) Central Power Plant (CPP) to evaluate carbon monoxide (CO) and oxides of nitrogen (NOx) emission rates from the CPP gas turbine cogeneration system and to evaluate CO emission rates from CPP Gas Turbine No. 10. The CPP cogeneration system consists of Gas Turbine Nos. 9 and 10 as well as CPP Boiler Nos. 7 and 8.

The purpose of the emissions test program was to evaluate CO and NOx emission rates from Gas Turbine No. 10 and from the gas turbine cogeneration system to demonstrate compliance with the provisions of AQD Renewable Operating (RO) Permit No. MI-ROP-M0675-2014a. Table I summarizes the results of the emissions test program. As summarized by Table I, CO emission rates from Gas Turbine No. 10 and CO and NOx emission rates from the CPP cogeneration system were less than the corresponding emission limitations.

Table I
Emissions Test Program Results Summary

Equipment	Pollutant	Fuel	Emission Limit	Emission Limit Units	Average Test Result	Average Test Result Units
Turbine 10	CO	Gas	7.54	lbs/hr	0.86	lbs/hr
Turbine 10	CO	Oil	37.87	lbs/hr	2.02	lbs/hr
Cogeneration System	NOx	Gas	30.4	lbs/hr	23.5	lbs/hr
Cogeneration System	NOx	Oil	47.3	lbs/hr	39.4	lbs/hr
Cogeneration System	CO	Gas	29.0	lbs/hr	17.7	lbs/hr
Cogeneration System	CO	Oil	72.0	lbs/hr	7.9	lbs/hr

1. Introduction

BT Environmental Consulting, Inc. (BTEC) was retained by The University of Michigan Central Power Plant (CPP) to evaluate carbon monoxide (CO) and oxides of nitrogen (NOx) emission rates from the CPP gas turbine cogeneration system and to evaluate CO emission rates from CPP Gas Turbine No. 10. The CPP cogeneration system consists of Gas Turbine Nos. 9 and 10 as well as CPP Boiler Nos. 7 and 8. The purpose of this document is to present the results of the emissions test program.

The Air Quality Division (AQD) of Michigan's Department of Environmental Quality has published a guidance document entitled "Format for Submittal of Source Emission Test Plans and Reports" (December 2013). This document is provided as Appendix A. The following is a summary of the emissions test program and results in the format suggested by the aforementioned document.

1.a Identification, Location, and Dates of Test

CO emission rates from Gas Turbine No. 10 were evaluated (with the turbine firing gas and with the turbine firing oil) on March 19, 2018. CO and NOx emission rates from the CPP gas turbine cogeneration system (with the turbines firing gas and with the turbines firing oil) were evaluated on March 20 and 21, 2018. CPP is located at 1120 East Huron Street, Ann Arbor, Michigan.

1.b Purpose of Testing

The purpose of the emissions test program was to evaluate CO and NOx emission rates from Gas Turbine No. 10 and from the gas turbine cogeneration system to demonstrate compliance with the provisions of AQD Renewable Operating (RO) Permit No. MI-ROP-M0675-2014a.

1.c Source Description

CPP Gas Turbines 9 and 10 are both Centaur® Model T5900 industrial gas turbines manufactured by Solar Turbines, Inc. (Solar). The exhaust gases that exit Gas Turbines 9 and 10 are routed through heat recovery steam generators (Boiler 7 serving Gas Turbine 9 and Boiler 8 serving Gas Turbine 10). Located in the exhaust duct between the gas turbines and the heat recovery boilers are duct burners used to supply supplemental heat to the turbine exhaust gases. This duct burners fire natural gas only.

1.d Test Program Contact

The contact for information regarding the test program as well as the test report is as follows:

Mr. Stephen O'Rielly
Manager
The University of Michigan
Environmental, Health, & Safety (EHS)
Campus Safety Services Building
1239 Kipke Drive
Ann Arbor, Michigan 48109
(734) 763-4642

1.e Testing Personnel

Names and affiliations for all personnel who were present during the testing program are summarized by Table 1.

Table 1
Testing Personnel

Name	Affiliation
Brandi Campbell	UM – EHS
Jim O'Brien	UM – CPP
Randal Tysar	BTEC
Steve Smith	BTEC
Dave Trahan	BTEC
Mason Sakshaug	BTEC
Jake Zott	BTEC
Mark Dziadosz	MDEQ – AQD
Gina Hines	MDEQ-AQD

2. Summary of Results

Sections 2.a through 2.d summarize the results of the emissions test program.

2.a Operating Data

The following turbine operating data was recorded for each test run:

- Turbine operating load
- Turbine fuel flowrate
- Turbine water flowrate

The data recorded during the emissions test program is summarized by Appendix B.

2.b Applicable Permit

The CPP cogeneration system is included in RO Permit No. MI-ROP-M0675-2014a.

2.c Results

The results of the emission test program are summarized by Tables 2 through 5.

2.d Emission Regulation Comparison

Table 6 presents a comparison of the average emission rates summarized by Tables 2 through 5 to emission limitations included in RO Permit No. MI-ROP-M0675-2014a.

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3. Source Description

Sections 3.a through 3.e provide a detailed description of the process.

3.a Process Description

CPP Gas Turbines 9 and 10 are Centaur® Model T5900 industrial gas turbines manufactured by Solar Turbines, Inc. (Solar). The turbine compressor compresses air to feed to the turbine combustor. At the combustor, the compressed air is mixed with either natural gas or distillate fuel oil and the fuel is burned. The increase in gas pressure in the combustor section causes the exhaust gases to exit through the power turbine section. This power turbine is connected to a single shaft that drives the turbine compressor as well as an electrical generator.

The exhaust gases that exit Gas Turbines 9 and 10 are routed through heat recovery steam generators (Boiler 7 serving Gas Turbine 9 and Boiler 8 serving Gas Turbine 10). Located in the exhaust duct between the gas turbines and the heat recovery boilers are duct burners used to supply supplemental heat to the turbine exhaust gases. This duct burners fire natural gas only.

Relevant parameters for the Gas Turbines are summarized as follows:

Turbine Manufacturer:	Solar Turbines, Inc.
Turbine Model:	Centaur® 50-T5900
Turbine Fuels:	Natural Gas or Distillate Fuel Oil
Power Rating at 59°F:	4012 kW (natural gas); 3908 kW (distillate oil)
Power Rating at 20°F:	4503 kW (natural gas); 4393 kW (distillate oil)
Heat Input Rating (59°F):	50.8 MMBtu/hr (natural gas); 49.6 MMBtu/hr (distillate oil)
Heat Input Rating (20°F):	55.8 MMBtu/hr (natural gas); 54.6 MMBtu/hr (distillate oil)
Boiler Manufacturer:	Zurn, Inc.
Boiler Rating:	65,000 pounds steam per hour
Duct Burner Fuel:	Natural Gas

The function of the combined cycle turbine system is to provide electricity and steam on a continuous basis. Consequently, normal operation of the system includes continuous operation of the turbine at 100% load.

Exhaust gases from the combined cycle system are routed to the existing exhaust stack that currently serves Gas Turbines 9 and 10 and Boilers 7 and 8. This exhaust stack, designated SVB0260-02, discharges at a point 159 feet above grade and has a discharge point diameter of 120 inches.

3.b Process Flow Diagram

Because of the simplicity of the process, a process flow diagram is not included.

3.c Raw and Finished Materials

The raw materials used by the cogeneration system include natural gas, distillate fuel oil, and water and the finished material is electricity. The flowrate of each raw material and the electricity and steam generation rates are summarized by Appendix B.

3.d Process Capacity

The rated capacity of the cogeneration system equipment is described in Section 3a. It should be noted, however, that the capacity of the turbine (kW) is variable dependent on ambient air conditions (e.g., temperature, pressure, humidity) as well as site-specific pressure losses (i.e., static pressure losses due to inlet and outlet ducting).

3.e Process Instrumentation

Process instrumentation relevant to the emissions test program includes the measurement of natural gas, distillate fuel oil, and water flowrates as well as the measurement of electricity and steam generation rates. Natural gas, fuel oil, and water flowrates are monitored using turbine meters. These meters have been in place since the original cogeneration system was installed (in 1989).

4. Sampling and Analytical Procedures

Sections 4.a through 4.d provide a summary of the sampling and analytical procedures that were used to verify emission rates from Gas Turbine 10 and the cogeneration system.

4.a Sampling Train and Field Procedures

The NO_x content of the exhaust gas was measured using a Teledyne T200H NO_x gas analyzer, the CO content of the exhaust gas was measured using a Teledyne 300EM CO gas analyzer and the O_2 and CO_2 content was measured using a Servomex 4100 CO_2/O_2 gas analyzer. A sample of the gas stream was drawn through an insulated stainless-steel probe with an in-line glass fiber filter to remove any particulate, a heated Teflon® sample line, and through a Universal Analyzers 3080PV electronic sample conditioner to remove the moisture from the sample before it enters the analyzers. Data was recorded at 4-second intervals on a PC equipped with data acquisition software.

For analyzer calibrations, calibration gases will be mixed to desired concentrations using an Environics Series 4040 Computerized Gas Dilution System. The Series 4040 consists of a single chassis with four mass flow controllers. The mass flow controllers are factory-calibrated using a primary flow standard traceable to the United State's National Institute of Standards and Technology (NIST). Each flow controller utilizes an 11-point calibration table with linear interpolation, to increase accuracy and reduce flow controller nonlinearity. A schematic drawing of the continuous emission system is provided as Figure 1.

Stack gas velocity traverses were conducted in accordance with the procedures outlined in Methods 1 and 2. An S-type pitot tube and thermocouple assembly calibrated in accordance with Method 2, Section 4.1.1 was used to measure exhaust gas velocity pressures and temperatures during testing of the cogeneration system. Molecular weight determinations were conducted according to Method 3A.

Moisture content was determined from the condensate collected in a Method 4 sampling train. The moisture content train consisted of (1) a stainless steel probe, (2) a set of four Greensburg-Smith (GS) impingers with the first modified and second standard GS impingers each containing 100 milliliters (mL) of deionized water, a third dry modified GS impinger and a fourth modified GS impinger containing approximately 800 grams of silica gel desiccant, (3) a length of sample line, and (4) a Nutech® control case equipped with a pump, dry gas meter, and calibrated orifice.

Sampling and analysis procedures followed the methodologies of the following emissions test methods codified at Title 40, Part 60, Appendix A of the Code of Federal Regulations (40 CFR 60, Appendix A):

- Method 1 - *"Sample and Velocity Traverses for Stationary Sources"* was used to determine the sampling location and the stack traverse points for evaluation of the cogeneration system.

- Method 2 - *"Determination of Stack Gas Velocity and Volumetric Flowrate"* was used to determine average exhaust gas velocity from the cogeneration system.
- Method 3A - *"Determination of Oxygen and Carbon Dioxide Concentrations in Emissions from Stationary Sources"* was used to evaluate the oxygen content of the exhaust.
- Method 4 - *"Determination of Moisture Content in Stack Gases"* was used to determine the moisture content of the exhaust gas from the cogeneration system.
- Method 7E - *"Determination of Nitrogen Oxides Emissions from Stationary Sources"* was used to determine the concentration of nitrogen oxides in the exhaust gas from the cogeneration system.
- Method 10 - *"Determination of Carbon Monoxide Emissions from Stationary Sources"* was used to determine the carbon monoxide concentration of the exhaust gas.
- Method 19 - *"Determination of Sulfur Dioxide Removal Efficiency and Particulate Matter, Sulfur Dioxide, and Nitrogen Oxide Emission Rates"* was used to determine CO emission rates from Turbine 10.

In general, BTEC (1) monitored CO and O_2 concentrations in the Turbine 10 exhaust using Methods 3A and 10 and calculated CO emission rates using fuel flowrate and fuel higher heating value data provided by CPP, and (2) monitored exhaust gas CO, NOx, $CO_2$and O_2 concentrations in the common cogeneration system exhaust using Methods 3A, 7E, and 10 and measured exhaust gas flowrate and exhaust gas moisture content using Methods 1 through 4.

4.b Recovery and Analytical Procedures

Because all measurements were conducted using on-line analyzers, no samples were recovered during the test program.

4.c Sampling Ports

Cogeneration system sampling ports are located in the combined cogeneration system exhaust duct prior to its discharge to the masonry exhaust stack.

4.d Traverse Points

Traverse points for the cogeneration are show in Figure 2.

5. Test Results and Discussion

Sections 5.a through 5.k provide a summary of the test results.

5.a Results Tabulation

The results of the test program are summarized by Tables 2 through 6. Raw analyzer data is also provided in electronic form in Appendix C.

5.b Discussion of Results

As summarized by Table 6, all results were well below permit allowable emission limits.

5.c Sampling Procedure Variations

No sampling procedure variations were used during the emissions test program. It should be noted, however, that cogeneration system moisture content data was recorded electronically in the field and, consequently, no moisture field data sheets are available. However, tables summarizing the moisture data are included in Appendix F. In addition, CO emission rates from Gas Turbine No. 10 were determined from triplicate (on each fuel) 21-minute test runs as opposed to triplicate 60-minute test runs as specified by the MDEQ test plan approval letter included in Appendix G. This test protocol change was approved by MDEQ in the field during testing.

5.d Process or Control Device Upsets

No process or control device upsets occurred during the emissions test program.

5.e Control Device Maintenance

There is no add-on control device for the cogeneration system.

5.f Re-Test Changes

The test program performed was not previously performed.

5.g Audit Sample Analyses

No audit samples were requested by AQD.

5.h Calibration Sheets

Field quality assurance/quality control procedures consisted of the analyzer calibrations required by and in conformance with the performance specifications of Methods 2, 3A, 4, 7E, and 10. Calibration gases were mixed to desired concentrations using an Environics

Series 4040 Computerized Gas Dilution System. The Series 4040 consists of a single chassis with four mass flow controllers. The mass flow controllers are factory-calibrated using a primary flow standard traceable to the United States National Institute of Standards and Technology (NIST). Each flow controller utilizes an 11 point calibration table with linear interpolation, to increase accuracy and reduce flow controller nonlinearity.

A field quality assurance check of the system was performed pursuant to Method 205 by setting the diluted concentration to a value identical to a Protocol 1 calibration gas and then verifying that the analyzer response is the same with the diluted gas as with the Protocol 1 gas. In addition, test program quality assurance included a NO_2 to NO conversion efficiency test and system bias checks. Relevant equipment calibration information is provided in Appendix D.

5.i Sample Calculations

Sample calculations are provided as Appendix E.

5.j Field Data Sheets

Copies of field data sheets and relevant field notes are provided in Appendix F.

5.k Laboratory Data

No laboratory analysis was included in this test program.

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Table 2
Turbine 10 Gas CO Emission Rates
University of Michigan
Ann Arbor, Michigan
BTEC Project No. 049AS-239748
Sampling Date: 3/19/2018

Parameter	Run 1	Run 2	Run 3	Average
Test Run Date	3/19/2018	3/19/2018	3/19/2018	
Test Run Time	8:35-9:00	9:08-9:28	9:39-9:59	
Average Fuel Flowrate (kscfh)	52.3	52.2	52.1	**52.2**
Natural Gas Gross Heating Value (Btu/scf)	1,066	1,066	1,066	**1,066**
Turbine Heat Input Rate (MMBtu/hr)	55.7	55.7	55.6	**55.7**
Oxygen Concentration (%)	15.4	15.4	15.4	**15.4**
Oxygen Concentration (%, drift corrected as per USEPA 7E)	15.4	15.5	15.5	**15.4**
Outlet Carbon Monoxide Concentration (ppmv)	7.2	6.9	6.8	**7.0**
Outlet CO Concentration (ppmv, corrected as per USEPA 7E)	6.5	6.3	6.3	**6.4**
CO Emission Rate (lb/MMBtu)	**0.02**	**0.02**	**0.02**	**0.02**
CO Emission Rate (lb/hr)	**0.87**	**0.86**	**0.86**	**0.86**

O_2 Correction			
Co	0.22	0.26	0.19
Cma	10.06	10.06	10.06
Cm	10.17	10.14	10.08

CO Correction			
Co	0.86	0.74	0.69
Cma	50.4	50.4	50.4
Cm	49.81	49.56	49.55

kscfh = 1,000 standard cubic feet per hour
ppmv = parts per million on a volume-to-volume basis
lb/hr = pounds per hour
MW = molecular weight (CO = 28.01, NOx = 46.01, SO_2 = 64.05, C_3H_8 = 44.10, carbon = 12.01)
24.14 = molar volume of air at standard conditions (70 °F, 29.92" Hg)
35.31 = ft^3 per m^3
453600 = mg per lb

Co= Average of initial and final zero gases
Cma=Actual concentration of the calibration gas
Cm= Average of initial and final calibration gases
C_c=KC_{meas}
where Cc = Concentration as Carbon (ppmv), K= Carbon equivalent correction factor (3 for Propane)
and C_{meas} = concentration as measured (as propane)

Table 3
Turbine 10 Oil CO Emission Rates
University of Michigan
Ann Arbor, Michigan
BTEC Project No. 049AS-239748
Sampling Date: 3/19/2018

Parameter	Run 1	Run 2	Run 3	Average
Test Run Date	3/19/2018	3/19/2018	3/19/2018	
Test Run Time	12:15-12:35	12:49-13:09	13:18-13:38	
Average Fuel Flowrate (gal/hr)	388.2	387.5	385.7	**387**
Fuel Oil Gross Heating Value (Btu/gal)	138,480	138,480	138,480	**138,480**
Turbine Heat Input Rate (MMBtu/hr)	53.8	53.7	53.4	**53.6**
Oxygen Concentration (%)	16.4	16.2	15.9	**16.2**
Oxygen Concentration (%, drift corrected as per USEPA 7E)	16.3	16.0	15.8	**16.0**
Outlet Carbon Monoxide Concentration (ppmv)	13.0	13.2	14.2	**13.5**
Outlet CO Concentration (ppmv, corrected as per USEPA 7E)	12.7	12.8	13.9	**13.1**
CO Emission Rate (lb/MMBtu)	**0.04**	**0.04**	**0.04**	**0.04**
CO Emission Rate (lb/hr)	**2.07**	**1.94**	**2.04**	**2.02**

O_2 Correction			
Co	0.20	0.28	0.26
Cma	10.06	10.06	10.06
Cm	10.18	10.28	10.22

CO Correction			
Co	0.71	0.74	0.74
Cma	50.4	50.4	50.4
Cm	49.71	49.79	49.79

ppmv = parts per million on a volume-to-volume basis
lb/hr = pounds per hour
MW = molecular weight (CO = 28.01, NOx = 46.01, SO_2 = 64.05, C_3H_8 = 44.10, carbon = 12.01)
24.14 = molar volume of air at standard conditions (70 °F, 29.92" Hg)
35.31 = ft^3 per m^3
453600 = mg per lb

Co= Average of initial and final zero gases
Cma=Actual concentration of the calibration gas
Cm= Average of initial and final calibration gases

Table 4
Cogen Gas NOx and CO Emission Rates
University of Michigan
Ann Arbor, Michigan
BTEC Project No. 049AS-239748
Sampling Date: 3/20/2018

Parameter	Run 1	Run 2	Run 3	Average
Test Run Date	3/20/2018	3/20/2018	3/20/2018	
Test Run Time	8:07-9:35	9:50-10:50	11:06-12:06	
Outlet Flowrate (dscfm)	66,045	65,299	63,864	**65,069**
Oxygen Concentration (%)	10	11	12	**10.8**
Oxygen Concentration (%, drift corrected as per USEPA 7E)	9.5	10.8	11.7	**10.7**
Carbon Dioxide Concentration (%)	6.6	6	5	**5.9**
Carbon Dioxide Concentration (%, drift corrected as per USEPA 7E)	6.5	5.8	5.2	**5.8**
Outlet Oxides of Nitrogen Concentration (ppmv)	53.6	50.5	47.8	**50.6**
Outlet NOx Concentration (ppmv, corrected as per USEPA 7E)	54.0	50.3	47.5	**50.6**
NOx Emission Rate (lb/hr)	**25.3**	**23.5**	**21.8**	**23.5**
NOx Emission Rate (lb/hr) (corrected as per USEPA 7E)	**25.5**	**23.5**	**21.7**	**23.5**
Outlet Carbon Monoxide Concentration (ppmv)	34.1	65.3	86.0	**61.8**
Outlet CO Concentration (ppmv, corrected as per USEPA 7E)	34.7	66.5	87.3	**62.8**
CO Emission Rate (lb/hr)	**9.8**	**18.5**	**23.9**	**17.4**
CO Emission Rate (lb/hr) (corrected as per USEPA 7E)	**10.0**	**18.9**	**24.2**	**17.7**

O_2 Correction			
Co	0.08	0.07	0.09
Cma	10.06	10.06	10.06
Cm	10.15	10.25	10.24

CO_2 Correction			
Co	0.05	0.02	0.03
Cma	10.07	10.07	10.07
Cm	10.11	10.04	10.04

NOx Correction			
Co	0.67	0.89	0.83
Cma	50.57	50.57	50.57
Cm	50.25	50.76	50.81

CO Correction			
Co	-0.05	-0.08	-0.01
Cma	50.4	50.4	50.4
Cm	49.55	49.52	49.63

dscfm = dry standard cubic feet per minute
ppmv = parts per million on a volume-to-volume basis
lb/hr = pounds per hour
MW = molecular weight (CO = 28.01, NOx = 46.01, SO_2 = 64.05, C_3H_8 = 44.10, carbon = 12.01)
24.14 = molar volume of air at standard conditions (70 °F, 29.92" Hg)
35.31 = ft^3 per m^3
453600 = mg per lb

Co= Average of initial and final zero gases
Cma=Actual concentration of the calibration gas
Cm= Average of initial and final calibration gases

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Table 5
Cogen Oil NOx and CO Emission Rates
University of Michigan
Ann Arbor, Michigan
BTEC Project No. 049AS-239748
Sampling Date: 3/21/2018

Parameter	Run 1	Run 2	Run 3	Average
Test Run Date	3/21/2018	3/21/2018	3/21/2018	
Test Run Time	7:23-8:23	8:35-9:35	9:52-10:52	
Outlet Flowrate (dscfm)	64,909	63,405	62,406	**63,573**
Oxygen Concentration (%)	10	10	10	**10.4**
Oxygen Concentration (%, drift corrected as per USEPA 7E)	10.0	10.3	10.4	**10.2**
Carbon Dioxide Concentration (%)	7	7	7	**7.1**
Carbon Dioxide Concentration (%, drift corrected as per USEPA 7E)	7.2	7.0	7.0	**7.1**
Outlet Oxides of Nitrogen Concentration (ppmv)	85.9	84.6	84.7	**85.0**
Outlet NOx Concentration (ppmv, corrected as per USEPA 7E)	87.8	86.5	86.5	**86.9**
NOx Emission Rate (lb/hr)	**39.8**	**38.3**	**37.7**	**38.6**
NOx Emission Rate (lb/hr) (corrected as per USEPA 7E)	**40.7**	**39.1**	**38.5**	**39.4**
Outlet Carbon Monoxide Concentration (ppmv)	25.3	30.1	30.6	**28.7**
Outlet CO Concentration (ppmv, corrected as per USEPA 7E)	25.2	29.9	30.4	**28.5**
CO Emission Rate (lb/hr)	**7.1**	**8.3**	**8.3**	**7.9**
CO Emission Rate (lb/hr) (corrected as per USEPA 7E)	**7.1**	**8.2**	**8.3**	**7.9**

O_2 Correction			
Co	0.24	0.24	0.20
Cma	10.06	10.06	10.06
Cm	10.27	10.29	10.15

CO_2 Correction			
Co	0.12	0.12	0.14
Cma	10.07	10.07	10.07
Cm	10.08	10.11	10.20

NOx Correction			
Co	0.21	0.68	0.76
Cma	90.49	90.49	90.49
Cm	88.53	88.49	88.57

CO Correction			
Co	0.25	0.24	0.18
Cma	50.4	50.4	50.4
Cm	50.28	50.58	50.65

dscfm = dry standard cubic feet per minute
ppmv = parts per million on a volume-to-volume basis
lb/hr = pounds per hour
MW = molecular weight (CO = 28.01, NOx = 46.01, SO_2 = 64.05, C_3H_8 = 44.10, carbon = 12.01)
24.14 = molar volume of air at standard conditions (70 °F, 29.92" Hg)
35.31 = ft^3 per m^3
453600 = mg per lb

Co= Average of initial and final zero gases
Cma=Actual concentration of the calibration gas
Cm= Average of initial and final calibration gases

Table 6
Emission Regulation Comparison Summary
The Unversity of Michigan
Central Power Plant
Turbine 10 and Cogeneration System
Sampling Date: March 2018

Equipment	Pollutant	Fuel	Emission Limit	Emission Limit Units	Average Test Result	Average Test Result Units
Turbine 10	CO	Gas	7.54	lbs/hr	0.86	lbs/hr
Turbine 10	CO	Oil	37.87	lbs/hr	2.02	lbs/hr
Cogeneration System	NOx	Gas	30.4	lbs/hr	23.5	lbs/hr
Cogeneration System	NOx	Oil	47.3	lbs/hr	39.4	lbs/hr
Cogeneration System	CO	Gas	29.0	lbs/hr	17.7	lbs/hr
Cogeneration System	CO	Oil	72.0	lbs/hr	7.9	lbs/hr

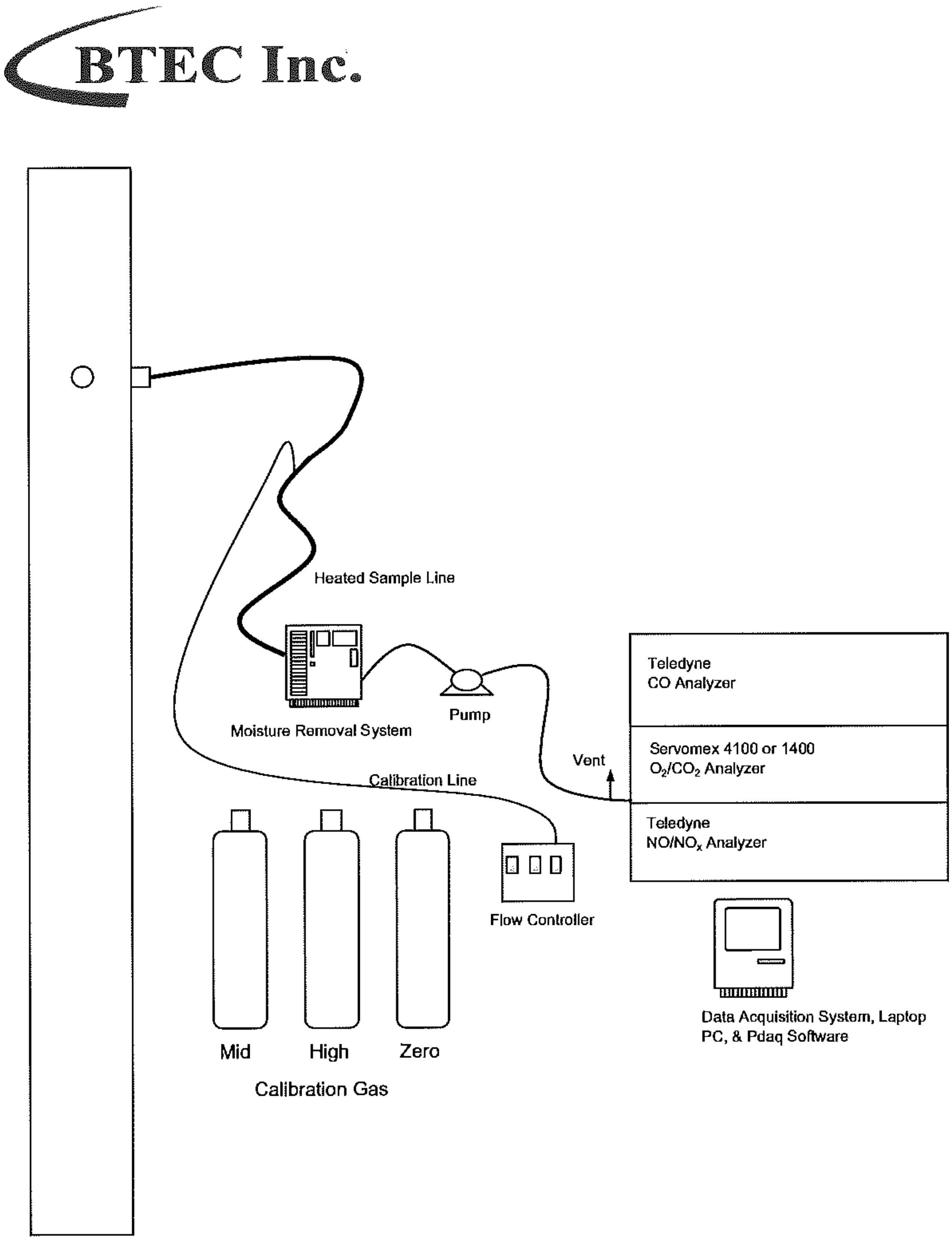


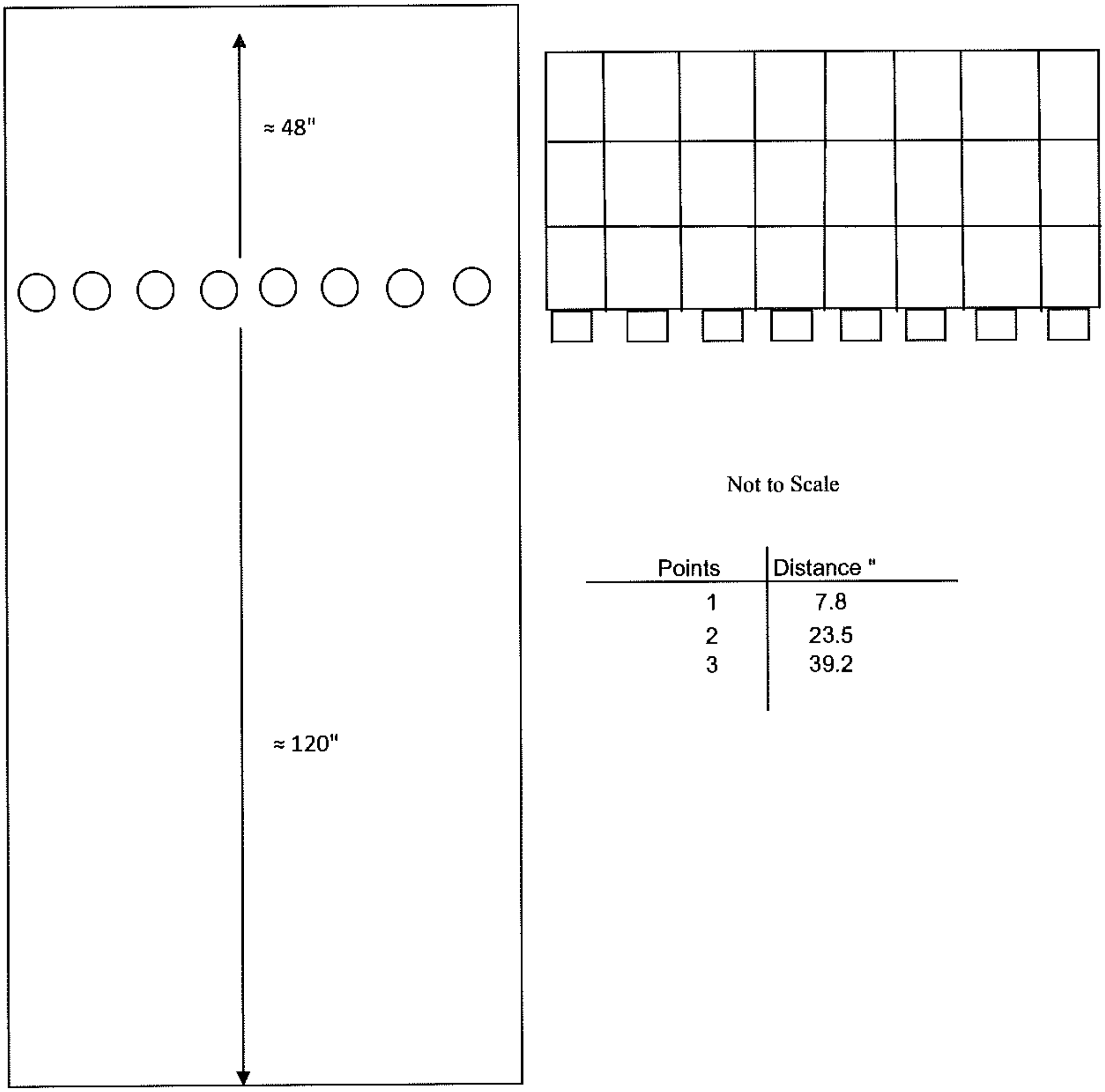
Figure No. 1

Site: **USEPA Method 3A, 7E, and 10** **University of Michigan** **Ann Arbor, Michigan**	**Sampling Date:** **March 2018**	**BT Environmental Consulting Inc.** **4949 Fernlee Avenue** **Royal Oak, MI 48073**

BTEC Inc.

Stack Dimensions:

Depth:	47	inches
Width:	93	inches



Not to Scale

Points	Distance "
1	7.8
2	23.5
3	39.2

Figure No. 2

Site: **Cogen** **University of Michigan** **Ann Arbor, Michigan**	**Sampling Date:** **March 20-21, 2018**	**BT Environmental Consulting, Inc.** **4949 Fernlee Avenue** **Royal Oak, Michigan 48073**