Alternative Monitoring Protocol
Predictive Emissions Monitoring Systems

For

Natural Gas-Fired Boiler No. 6 (EU-BOILER6)
Natural Gas-Fired Boiler No. 7 (EU-BOILER7)

Prepared for:

Detroit Thermal Beacon Heating Plant
Detroit, Michigan

Prepared by:

AMP-Cherokee Environmental Solutions
Angier, North Carolina

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INTRODUCTION

Detroit Renewable Energy (d.b.a. Detroit Thermal) operates a heating plant (the Beacon Plant) located at 541 Madison Avenue in Detroit, Michigan. Detroit Thermal operates several steam boilers at the plant to supply steam to commercial customers in the downtown Detroit area. Two of the boilers at the facility (Boilers 6 and 7) are package boilers with rated heat inputs of 180.2 million British Thermal Units per hour (MMBtu/hr). The boilers combust natural gas, and are equipped with low NO_X burners and flue gas recirculation for the control of NO_X emissions. Renewable Operating Permit (ROP) No. MI-ROP-B2814-2014 was issued to Detroit Thermal on August 23, 2014 by the Michigan Department of Environmental Quality Air Quality Division. A copy of the permit is included in Appendix A.

Air emissions from the boilers are regulated under the ROP as well as 40 CFR Part 60 Subpart Db, *Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units*. Detroit Thermal is required to install, certify, maintain, and operate continuous emissions monitoring systems (CEMS) to determine the hourly NO_X emission rates in parts per million (ppm) or pounds per million British thermal units (lb/MMBtu). Detroit Thermal has elected to install, certify, maintain, and operate Predictive Emissions Monitoring Systems (PEMS) in lieu of CEMS. A PEMS will be installed on each boiler. Each PEMS will be commissioned and certified following the procedures in 40 CFR 60 Appendix B, Performance Specification 16, *Specifications and Test Procedures for Predictive Emission Monitoring Systems in Stationary Sources.*

Appendix 7 of the ROP requires Detroit Thermal to calculate emissions of sulfur dioxide (SO_2) and carbon monoxide (CO) based on the amount of fuel fired. Sulfur dioxide is calculated using a default emission factor for natural gas of 0.06 lb SO_2 per $MMft^3$ of natural gas combusted. Emissions of CO are calculated based on CO emission factors developed during 2015 stack testing. The CO emission factor for Boiler No. 6 is 0.0014 lb/MMBtu. The CO emission factor for Boiler No. 7 is 0.0111 lb/MMBtu.

Detroit Thermal has contracted AMP-Cherokee Environmental Solutions (AMP-Cherokee) of Angier, North Carolina to design, fabricate, install and commission a Predictive Emissions Monitoring System (PEMS) for each boiler. Each PEMS will consist of an Allen-Bradley CompactLogix programmable logic controller (PLC) and a touch panel personal computer (PPC). Each PEMS will monitor up to 15 process inputs and predict the stack concentrations of NO_X and O_2, and calculate NO_X emissions in units of lb/MMBtu using fuel factors for natural gas. Emissions data from both PEMS will be recorded by a data acquisition and handling system (DAHS) which will also be supplied by AMP-Cherokee. The ProLogix P60™ DAHS (ProLogix) will record emissions data predicted by each PEMS, process the data, and provide daily concentrations, emissions, and excess emissions reports. The ProLogix DAHS will operate on a PEMS Polling PC, which will also serve as the emissions data historian.

This Alternative Monitoring Protocol describes the methodology, certification, and quality assurance procedures that will be used to ensure that the PEMS calculates and reports emissions data that are representative of actual conditions. The following sections provide discussions of:

- Cogeneration unit process description;
- Monitoring system design;
- Procedures that will be used during emissions model development;
- Initial verification procedures; and,
- Ongoing quality assurance

PROCESS DESCRIPTION

The following paragraphs present discussions of the steam boilers and the PEMS that will be used to calculate emissions from the boiler.

The steam boilers are Nebraska package steam boilers that are used to supply steam to Detroit Thermal customers in the downtown Detroit area. The boilers are designated EU-BOILER6 (Boiler No. 6) and EU-BOILER7 (Boiler No. 7). The boilers were built in 2006 and reclassified to higher operating pressure in 2014. Each boiler is a 180.2 MMBtu/hour natural gas-fired boiler, and is equipped with low-NOx burners and flue gas recirculation. Basic design specifications are presented in Table 1.

Table 1
Steam Boiler No. 6 and No. 7 Specifications

Equipment	Natural Gas-fired Steam Boiler
Steam Capacity	150,000 pounds per hour
Heat Input	180.2 MMBtu per hour
Steam Pressure	
Steam Temperature	
Design Pressure	
NOX Permit Limit	0.036 lb/MMBtu
CO Permit Limit	84.6 lb/hr
SO2 Permit Limit	39 tons/yr (Rolling 12-months)

Mechanisms of NOX Formation

The primary pollutants of interest from the boilers is NO_X, and to a lesser extent carbon monoxide (CO). Based on the requirements of the ROPs, each PEMS will calculate emissions of NO_X. Oxygen will be calculated as the diluent gas.

Natural gas is one of the major combustion fuels used throughout the country. It is mainly used to generate industrial and utility electric power, produce industrial process steam and heat, and heat residential and commercial space. Natural gas consists of a high percentage of methane (generally above 85 percent) and varying amounts of ethane, propane, butane, and inert compounds (typically nitrogen, carbon dioxide, and helium). The average gross heating value of natural gas is approximately 1,020 British thermal units per standard cubic foot (Btu/scf), usually varying from 950 to 1,050 Btu/scf.

There are three mechanisms by which nitrogen oxides are formed during natural gas combustion. The principal mechanism of NO_X formation in natural gas combustion is thermal NO_X. The thermal NO_X mechanism occurs through the thermal dissociation and subsequent reaction of nitrogen (N_2) and oxygen (O_2) molecules in the combustion air. Most NO_X formed through the thermal NO_X mechanism occurs in the high temperature flame zone near the burners. The formation of thermal NO_X is affected by three furnace-zone factors: (1) oxygen concentration, (2) peak temperature, and (3) time of exposure at peak temperature. As these three factors increase, NO_X emission levels increase. The emission trends due to changes in these factors are fairly consistent for all types of natural gas-fired boilers and furnaces. Emission levels vary considerably with the type and size of combustor and with operating conditions (e.g., combustion air temperature, volumetric heat release rate, load, and excess oxygen level).

The second mechanism of NO_X formation, called prompt NO_X, occurs through early reactions of nitrogen molecules in the combustion air and hydrocarbon radicals from the fuel. Prompt NO_X reactions occur within the flame and are usually negligible when compared to the amount of NO_X formed through the thermal NO_X mechanism. However, prompt NO_X levels may become significant with ultra-low-NO_X burners.

The third mechanism of NO_X formation, called fuel NO_X, stems from the evolution and reaction of fuel-bound nitrogen compounds with oxygen. Due to the characteristically low fuel nitrogen content of natural gas, NO_X formation through the fuel NO_X mechanism is insignificant.

Currently, the two most prevalent combustion control techniques used to reduce NO_X emissions from natural gas-fired boilers are flue gas recirculation (FGR) and low NO_X burners. In an FGR system, a portion of the flue gas is recycled from the stack to the burner windbox. Upon entering the windbox, the recirculated gas is mixed with combustion air prior to being fed to the burner. The recycled flue gas consists of combustion products which act as inerts during combustion of the fuel/air mixture. The FGR system reduces NO_X emissions by two mechanisms. Primarily, the recirculated gas acts as a dilutent to reduce combustion temperatures, thus suppressing the thermal NO_X mechanism. To a lesser extent, FGR also reduces NO_X formation by lowering the oxygen concentration in the primary flame zone. The amount of recirculated flue gas is a key operating parameter influencing NO_X emission rates for these systems. An FGR system is normally used in combination with specially designed low NO_X burners capable of sustaining a stable flame with the increased inert gas flow resulting from the use of FGR. When low NO_X burners and FGR are used in combination, these techniques are capable of reducing NO_X emissions by 60 to 90 percent.

Low NO_X burners reduce NO_X by accomplishing the combustion process in stages. Staging partially delays the combustion process, resulting in a cooler flame which suppresses thermal NO_X formation. The two most common types of low NO_X burners being applied to natural gas-fired boilers are staged air burners and staged fuel burners. NO_X emission reductions of 40 to 85 percent (relative to uncontrolled emission levels) have been observed with low NO_X burners.

MONITORING SYSTEM DESIGN

The AMP-Cherokee Prologix P60™ PEMS is a PLC-based system which calculates pollutant emissions from sensor inputs using high-order polynomial equations. The PEMS design is an extension of AMP-Cherokee's CEMS controller software; the PEMS portion of the software calculates pollutant and diluent gas concentrations as functions of process sensor inputs. The process sensor inputs are read by the PLC via analog and/or digital signals, MODBUS or serial communications, PLC to PLC messaging, or via OPC server software from the facility distributive control system (DCS). Sensor data is validated, and predicted gas concentrations for each sensor are calculated using relationships that are defined during emissions model development. The final prediction for each parameter is determined by calculating a weighted average of the individual predictions. After the final prediction has been made, additional data processing and validation is conducted using the proven procedures in the CEMS controller algorithm. The PEMS prediction algorithm replaces the gas analyzers, and the validated gas predictions are processed in a similar fashion to gas analyzer data.

PEMS Hardware

The PEMS hardware is comprised of three basic components: the PLC, a touch panel PC, and a data historian and report server. The base PLC is an Allen-Bradley PLC assembly comprised of a CompactLogix 1769-L33ER processor, 1769-PA2 AC power supply, and 1769-QI16 16-point 24 VDC digital input module. Additional I/O modules (analog signal, temperature, digital output) can be added and configured as needed to meet project requirements. Protocol converters (TCP/IP, MODBUS, serial) can also be added and configured as needed to allow the collection of data by the PLC processor from devices that use these communications protocols.

The PLC is supported by a touch panel PC which is installed into the same instrument enclosure as the PLC. The panel PC is manufactured by Protech Technologies. The touch panel PC has a 15-inch touch screen, an Intel i3 processor, 8 Gb of RAM, and two 500 Gb hard disk drives that are configured in a redundant array. The components are mounted into a customer-supplied instrument enclosure, along with an uninterruptable power supply and associated support equipment.

The data historian and report server software is installed onto a Dell Precision T3620 Mini-tower Workstation. The data historian (also known as the polling PC) is equipped with a 23-inch monitor and Intel i5-6600 processor, 16 Gb of RAM and two 500 Gb hard disk drives that are configured in a redundant array. The polling PC provides data redundancy, secure storage of data, and will serve as a backup to the local panel PCs should they fail.

PEMS Software

The main software components include the PLC ladder logic program, AMP-Cherokee's Human/Machine Interface (HMI) software, Status Server Calculation Engine, and Microsoft SQL Express database software. The PEMS are supported by a data acquisition and handling system (DAHS). The DAHS is composed of Microsoft SQL Server software packages, Iconics ReportWorx report generation software, and Microsoft Excel software.

Drawings of the PEMS data flow and calculation algorithms are included in Appendix B. Drawing 00464-CP104 shows the hardware, software, and communications configuration of the PEMS PLCs, the PEMS touch panel PCs and the PEMS Polling virtual PC. In addition to the software packages that are used to collect, process, and store data, the PEMS PCs and the desktop PC will be configured with Kepware OPC server software. The software servers use the Open Platform Communications standard to transmit data between the PLCs the PCs and devices on the plant DCS.

Modeling Algorithm

Drawing 00464-CP105 shows the PEMS algorithm. Sensor data can be read by the PEMS PLC through a variety of inputs, such as analog or digital, PLC messaging, via MODBUS protocol, or via OPC across facility DCS. Process variables are read by the PLC and passed through a sensor validation system, and an emission calculation algorithm.

Sensor validation is accomplished through a 2-step process. During Level 1 validation, data from each sensor is validated in the PLC against a valid sensor range. If the measured sensor data is within the range of valid values for that sensor, the sensor is considered valid. If the measured sensor data is not within the range of valid values, the sensor is set to invalid by assigning a value of zero to the sensor value. During Level 2 validation, the number of sensors that have passed Level 1 validation are counted. If the total number of sensor inputs that have passed Level 1 validation are greater than or equal to three, then sensor data that has passed Level 1 validation is stored in the validated sensor database, and the values for each sensor are passed to the Status Server Calculation Engine. If less than three sensors are validated, the PLC data invalid status bit is set, which results in a PEMS DATA INVALID alarm.

The emission calculation algorithm (the calculation engine) calculates a parameter value for each validated sensor input. The PEMS parameters for the boilers are nitrogen oxides and oxygen. Each parameter is calculated using the following basic equations:

$$Pa_x = A(Sx) + B(Sx)^2 + C(Sx)^3 + D(Sx)^4 + bSx$$

Where:

Pa_x = Preliminary Parameter value for sensor x;

A, B, C, D = polynomial coefficients, derived through statistical comparison of parameter concentration versus sensor value during testing for model development;

Sx = Engineering value of sensor x;

b = coefficient for y-intercept, derived through statistical comparison of parameter value concentration sensor value during testing for model development.

The polynomial coefficients are programmed into the PLC via the HMI by authorized personnel, and are secured via password to prevent unauthorized changes to the equation.

Parameter values (i.e., NO_X and O_2 concentrations) are calculated for each valid sensor input. If a sensor has been invalidated by the validation sequence, then the parameter values calculated for that sensor are zero. Weighted parameters for each sensor are calculated by multiplying the preliminary parameter values by a user-defined weighting factor:

$$Pa_w = WPa_x$$

Where:

Pa_w = Weighted parameter value for sensor x;

W = User defined weighting factor;

Pa_x = Parameter value for sensor x;

The final parameter value is calculated from a weighted average of the parameter values calculated from each of the valid sensor values:

$$Pa_f = \frac{\sum Pa_w}{\sum W}$$

Where:

Pa_f = Final parameter value;

Pa_w = Weighted parameter value for sensor x;

W = User defined weighting factor;

The weighting factors for each sensor are configured via the HMI by field technicians as part of the emission modeling process. The final parameter value is then stored in the SQL database for further processing.

Process Sensors

There are numerous process sensors available on both boilers which can be used to develop statistical relationships between the measured sensor values and NO_X and O_2 concentrations. Tables 2 and 3 present the sensor inputs for the boilers that were monitored during emissions testing for model development.

Table 2
Boiler No. 6 Process Sensors

Sensor Input No.	TAG ID	Description	LOW VALIDATION	HIGH VALIDATION
1	FT_60370_EU	Fuel Gas Flow	0	167500
2	FT_64310	Steam Flow Rate	0	160
3	FT_62070	Combustion Air Differential Pressure	3	96
4	BE_61300A	Flame Intensity Signal A	0	0
5	BE_61300B	Flame Intensity Signal B	0	0
6	TT_62600	Economizer Outlet Temperature	0	0
7	AIT_62200	Oxygen Analyzer	2.5	19.8
8	FT_60370	Gas Flow Transmitter	0	90.5
9	BOILER_DEM	Boiler Demand	9	90
10	FZ_62070	Air Damper Position (ACTUAL)	4.5	81
11	FT_62170	Flue Gas Recirculation Flow	0	0
12	PT_63450	Steam Header	0	0
13	FI_62070_O2_TRIMED	Air Flow percentage with O2 trim	2.9	96
14	FT_63000	Feedwater Flow Rate	0	0
15	FT_63812	Mud Drum Steam Flow	0	0

Table 3
Boiler No. 7 Process Sensors

Sensor Input No.	TAG ID	Description	LOW VALIDATION	HIGH VALIDATION
1	FT_70370_EU	Fuel Gas Flow	0	167600
2	FT_74310	Steam Flow Rate	0	160000
3	FT_72070	Combustion Air Differential Pressure	1.0	100
4	BE_71300A	Flame Intensity Signal A	0	0
5	BE_71300B	Flame Intensity Signal B	0	0
6	TT_72600	Economizer Outlet Temperature	0	0
7	AIT_72200	Oxygen Analyzer	3.0	21.1
8	FT_70370	Gas Flow Transmitter	0	90.1
9	BOILER_DEM	Boiler Demand	10	90
10	FZ_72070	Air Damper Position (ACTUAL)	4.8	80
11	FT_72170	Flue Gas Recirculation Flow	0	0
12	PT_73450	Steam Header	0	0
13	FI_72070_O2_TRIMED	Air Flow percentage with O2 trim	0.9	100
14	FT_73000	Feedwater Flow Rate	0	0
15	FT_73812	Mud Drum Steam Flow	0	0

Data Reporting

Emissions data will be handled by the AMP-Cherokee Prologix P60 Data Acquisition and Handling System. Emissions and sensor data is stored into a Microsoft SQL Server database. Daily reports for concentration, emissions, and excess emissions are automatically generated each day using SQL procedures which query the database for the required records. Concentration, emissions, or excess emissions reports can also be manually requested for custom timeframes via the ReportWorx software interface. Users select the type of report desired and specify the beginning and ending of the time period. ReportWorx queries the SQL database and populates the report. The reports are available in Microsoft Excel, Adobe Portable Document Format (.pdf), and Hypertext Markup Language (html) formats.

EMISSIONS MODEL DEVELOPMENT

Emissions model development consisted of collecting quality assured emissions data from each boiler while operating over the entire design range of the units. Each unit was operated for approximately 1 hour at 10-percent load increments. Each load condition was run three times, and data from start up and shut down events was also collected. Emissions and sensor data was collected from Boiler 6 during the period from October 31 to November 2, 2016. Emissions and sensor data was recorded during 35 load conditions. Emissions and sensor data was collected from Boiler 7 during the period from October 29 to November 2, 2016. Emissions and sensor data was recorded during 35 load conditions. The load schedules were designed to ensure that emissions and sensor data was collected over the entire operating envelope of each unit. The load schedules were developed based on fuel inputs. The boilers were operated across a range of fuel inputs, from zero (i.e., shutdown) to maximum load (100%). Emissions data was collected during unit operations as well as during several startup and shutdown cycles.

Sensor QA

Prior to the start of emissions testing for model development, sensor data to the PEMS PLC was evaluated to ensure that the data being read by the PEMS PLCs was the same as the sensor data being sent by the boiler PLCs. Each boiler was operated at minimal loads, and the sensor data displayed by the boiler control HMIs were compared to the data displayed by the PEMS HMIs to ensure accuracy between the boiler control systems and the PEMS. Sensor ranges (operating envelopes) of each sensor was defined using the sensor data that was collected during emissions testing for model development.

Emissions Testing for Model Development

As stated previously, quality-assured emissions data was collected from each boiler while the boilers were being operated according to the pre-defined load schedules. An AMP-Cherokee MiniCEMS temporary CEMS was used to collect emissions data. The MiniCEMS consists of a portable, climate controlled shelter. The shelter contains sample conditioning, sample distribution, calibration, and probe blowback systems, a PLC-based CEMS controller, and a touch panel PC for data storage and operator interface with the CEMS. A MiniCEMS 200M NO_X/O_2 analyzer was used to measure concentrations of NO_X and O_2 in the boiler exhaust duct. The MiniCEMS 200M analyzer is custom-built for AMP-Cherokee by Teledyne Advanced Pollution Instrumentation and is based on the T200M NO_X/O_2 analyzer. Gas samples from the boiler exhaust duct were extracted using a heated sample probe and transported to the MiniCEMS shelter via a heated sample line. One-minute average concentration data was recorded by the MiniCEMS DAHS, and downloaded for subsequent data analysis.

Statistical Analysis of Sensor Data

At the conclusion of the emissions testing, the emissions data and the process data were analyzed to develop statistical relationships. Sensor parameters identified previously were compared to NO_X and O_2 concentrations and polynomial equations developed using a statistical data analysis software package such as Analyse-it®. After the equations and weighting factors were developed, the model was tested by inputting sensor data into the algorithm and comparing the calculated values of NO_X and O_2 with the CEMS test data.

Each model was installed into each PEMS PLC and the boilers were operated at low, mid, and high firing rates while the CEMS collected emissions data. One hour of data was collected at each load condition (approximately 30, 60, and 90 percent).

INITIAL VERIFICATION TEST PROCEDURES

The initial verification of each PEMS will be conducted via a Relative Accuracy Test Audit (RATA). Each PEMS is designed to provide emissions data for continual compliance. Therefore, emissions testing will be required to be conducted at three unit operating loads corresponding to low, mid, and high operating levels. A minimum of 10 Reference Method (RM) tests will be conducted at each operating load. The calculation of relative accuracy will be made by comparing a minimum of 9 sets of PEMS data with RM data.

Sensor Validation

Prior to starting the RATA, the PEMS input sensors to be used to calculate emissions will be documented. The range of minimum and maximum values (operating envelope) for each sensor will be defined and the integrity of the sensor operating envelope will be confirmed from statistical data analysis generated during the emissions model development process. If a sensor operates outside of the envelope, then that sensor will be invalidated and pollutant predictions calculated from that sensor will not be used. If the number of validated sensors at any time is less than three, then the PEMS data will be invalidated.

Relative Accuracy Test Audit

The RATA will consist of paired sets of reference method test runs and PEMS data. Relative accuracy will be calculated at each load condition in concentration units and in units of the emission standard (lb/MMBtu). The results of the RA data collected at the mid-level load condition will be analyzed to determine if bias exists between and PEMS data and the RM data. In addition to the calculation of RA, statistical tests will be performed on the data. A statistical variance (F-test) analysis will be conducted on the paired RA data from each operating level to determine if the PEMS and RM variances differ by more than might be expected from chance. A correlation analysis will be performed using the RA paired data from all operating levels to determine how well the PEMS and the RM data correlate. Note that the correlation analysis will not be conducted if the collected RM data does not exhibit a variation of more than 30 percent.

The PEMS will be considered to meet relative accuracy requirements of Performance Specification 16 (PS-16) if the relative accuracy of the PEMS does not exceed:

- 10 percent (if the PEMS pollutant measurements are greater than 100 ppm); or,
- 20 percent (if the PEMS pollutant measurements are between 100 ppm and 10 ppm); or,

- An absolute difference of 2 ppm (if the PEMS pollutant measurements are less than 10 ppm); and,
- An absolute difference of less than 1 percent (for PEMS diluent measurements)

The PEMS data will be considered to be biased if the result of the bias test shows that the arithmetic mean of the differences between the PEMS data and the RM data is greater that the absolute value of the confidence coefficient of the data set. If the PEMS is biased, then a bias adjustment factor as described in PS-16 equation 16-5 will be applied. The variance of the PEMS data will be considered acceptable if the calculated F-value is not greater that the critical F-value at the 95-percent confidence level. The PEMS correlation will be considered to be acceptable if the calculated r-value is greater than or equal to 0.8.

Test Methods

The basic test methods that will be employed will be EPA Test Methods 3A (oxygen) and 7E (nitrogen oxides). Gas samples will be extracted from the stack through a heated filter/probe, and transported to the RM analyzers via a heated sample line. Prior to introducing the gas sample to the analyzers, the gas will be filtered to remove entrained particulate matter, and cooled to condense uncombined moisture in the gas sample. The RM CEMS analyzers will be calibrated prior to each day of testing, and CEMS system bias checks will be conducted periodically during testing. The average analyzer responses recorded during each test run will be corrected using the results of the pre- and post-test bias checks.

During each test run, gas samples will be collected at each of 3 traverse points, for an equivalent amount of time (i.e., 7 minutes each for a 21-minute test run). Sample points will be located on a traverse line at 16.7, 50.0, and 83.3 percent of the stack cross-section.

ONGONG QUALITY ASSURANCE

To ensure the reliability and accuracy of each PEMS after the initial verification, ongoing quality assurance will be required. The following paragraphs describe the procedures that will be used to ensure reliability of the PEMS.

Sensor Evaluation

Sensors will be evaluated by the PEMS controller continuously using the 2-level sensor validation sub-model. For sensors that do not pass Level 1 validation, a value of zero is substituted for the senor input value and parameter values are not calculated. If the total number of validated sensors at any time is less than three, no parameter values are calculated and the PEMS logic sets a data invalid flag.

Relative Accuracy Audits

During the first year of operation of the PEMS after the initial certification, relative accuracy audits (RAAs) will be conducted quarterly on each PEMS. The RAAs will be conducted using a properly calibrated portable analyzer. A minimum of three 30-minute test runs will be conducted. The PEMS will be considered to meet relative accuracy requirements of Performance Specification 16 (PS-16) if the relative accuracy of the PEMS does not exceed:

- 10 percent (if the PEMS pollutant measurements are greater than 100 ppm); or,
- 20 percent (if the PEMS pollutant measurements are between 100 ppm and 10 ppm); or,
- An absolute difference of 2 ppm (if the PEMS pollutant measurements are less than 10 ppm); and,
- An absolute difference of less than 1 percent (for PEMS diluent measurements)

For the RAA, the statistical tests conducted during the RATA are not required. If either of the PEMS passes all quarterly RAAs in the first year, and passes the subsequent yearly RATA in the second year, the owner may elect to perform a single mid-year RAA in the second year in lieu of the quarterly RAAs, and this option may be repeated as long as the PEMS continues to pass the annual RATAs and the mid-year RAAs. If the PEMS fails a mid-year RAA or an annual RATA, then RAAs will be conducted each quarter until the PEMS passes both a year of quarterly RAAs and a subsequent RATA.

Relative Accuracy Test Audit

A RATA will be performed on each PEMS at the normal operating load on a yearly basis in the quarter that an RAA has not been performed. The RATA will consist of a minimum of 9 test runs using a CEMS composed of reference method analyzers. The PEMS will be considered to meet relative accuracy requirements of Performance Specification 16 (PS-16) if the relative accuracy of the PEMS does not exceed:

- 10 percent (if the PEMS pollutant measurements are greater than 100 ppm); or,
- 20 percent (if the PEMS pollutant measurements are between 100 ppm and 10 ppm); or,
- An absolute difference of 2 ppm (if the PEMS pollutant measurements are less than 10 ppm); and,
- An absolute difference of less than 1 percent (for PEMS diluent measurements)

APPENIDIX A
RENEWABLE OPERATING PERMIT

DEQ

Michigan Department of Environmental Quality
Air Quality Division

EFFECTIVE DATE: April 23, 2014

ISSUED TO

DETROIT THERMAL BEACON HEATING PLANT

State Registration Number (SRN): B2814

LOCATED AT

541 Madison, Detroit, Michigan 48226

RENEWABLE OPERATING PERMIT

Permit Number: MI-ROP-B2814-2014

Expiration Date: April 23, 2019

Administratively Complete ROP Renewal Application Due Between
October 23, 2017 and October 23, 2018

This Renewable Operating Permit (ROP) is issued in accordance with and subject to Section 5506(3) of Part 55, Air Pollution Control, of the Natural Resources and Environmental Protection Act, 1994 PA 451, as amended (Act 451). Pursuant to Michigan Air Pollution Control Rule 210(1), this ROP constitutes the permittee's authority to operate the stationary source identified above in accordance with the general conditions, special conditions and attachments contained herein. Operation of the stationary source and all emission units listed in the permit are subject to all applicable future or amended rules and regulations pursuant to Act 451 and the federal Clean Air Act.

SOURCE-WIDE PERMIT TO INSTALL

Permit Number: MI-PTI-B2814-2014

This Permit to Install (PTI) is issued in accordance with and subject to Section 5505(5) of Act 451. Pursuant to Michigan Air Pollution Control Rule 214a, the terms and conditions herein, identified by the underlying applicable requirement citation of Rule 201(1)(a), constitute a federally enforceable PTI. The PTI terms and conditions do not expire and remain in effect unless the criteria of Rule 201(6) are met. Operation of all emission units identified in the PTI is subject to all applicable future or amended rules and regulations pursuant to Act 451 and the federal Clean Air Act.

Michigan Department of Environmental Quality

Wilhemina McLemore, Detroit District Supervisor

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AUTHORITY AND ENFORCEABILITY

For the purpose of this permit, the **permittee** is defined as any person who owns or operates an emission unit at a stationary source for which this permit has been issued. The **department** is defined in Rule 104(d) as the Director of the Michigan Department of Environmental Quality (MDEQ) or his or her designee.

The permittee shall comply with all specific details in the permit terms and conditions and the cited underlying applicable requirements. All terms and conditions in this ROP are both federally enforceable and state enforceable unless otherwise footnoted. Certain terms and conditions are applicable to most stationary sources for which an ROP has been issued. These general conditions are included in Part A of this ROP. Other terms and conditions may apply to a specific emission unit, several emission units which are represented as a flexible group, or the entire stationary source which is represented as a Source-Wide group. Special conditions are identified in Parts B, C, D and/or the appendices.

In accordance with Rule 213(2)(a), all underlying applicable requirements are identified for each ROP term or condition. All terms and conditions that are included in a PTI, are streamlined, subsumed and/or are state-only enforceable will be noted as such.

In accordance with Section 5507 of Act 451, the permittee has included in the ROP application a compliance certification, a schedule of compliance, and a compliance plan. For applicable requirements with which the source is in compliance, the source will continue to comply with these requirements. For applicable requirements with which the source is not in compliance, the source will comply with the detailed schedule of compliance requirements that are incorporated as an appendix in this ROP. Furthermore, for any applicable requirements effective after the date of issuance of this ROP, the stationary source will meet the requirements on a timely basis, unless the underlying applicable requirement requires a more detailed schedule of compliance.

Issuance of this permit does not obviate the necessity of obtaining such permits or approvals from other units of government as required by law.

A. GENERAL CONDITIONS

Permit Enforceability

- All conditions in this permit are both federally enforceable and state enforceable unless otherwise noted. **(R 336.1213(5))**
- Those conditions that are hereby incorporated in a federally enforceable Source-Wide PTI pursuant to Rule 201(2)(d) are designated by footnote one. **(R 336.1213(5)(a), R 336.1214a(5))**
- Those conditions that are hereby incorporated in a state-only enforceable Source-Wide PTI pursuant to Rule 201(2)(c) are designated by footnote two. **(R 336.1213(5)(b), R 336.1214a(3))**

General Provisions

1. The permittee shall comply with all conditions of this ROP. Any ROP noncompliance constitutes a violation of Act 451, and is grounds for enforcement action, for ROP revocation or revision, or for denial of the renewal of the ROP. All terms and conditions of this ROP that are designated as federally enforceable are enforceable by the Administrator of the United States Environmental Protection Agency (USEPA) and by citizens under the provisions of the federal Clean Air Act (CAA). Any terms and conditions based on applicable requirements which are designated as "state-only" are not enforceable by the USEPA or citizens pursuant to the CAA. **(R 336.1213(1)(a))**

2. It shall not be a defense for the permittee in an enforcement action that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of this ROP. **(R 336.1213(1)(b))**

3. This ROP may be modified, revised, or revoked for cause. The filing of a request by the permittee for a permit modification, revision, or termination, or a notification of planned changes or anticipated noncompliance does not stay any ROP term or condition. This does not supersede or affect the ability of the permittee to make changes, at the permittee's own risk, pursuant to Rule 215 and Rule 216. **(R 336.1213(1)(c))**

4. The permittee shall allow the department, or an authorized representative of the department, upon presentation of credentials and other documents as may be required by law and upon stating the authority for and purpose of the investigation, to perform any of the following activities **(R 336.1213(1)(d))**:
   a. Enter, at reasonable times, a stationary source or other premises where emissions-related activity is conducted or where records must be kept under the conditions of the ROP.
   b. Have access to and copy, at reasonable times, any records that must be kept under the conditions of the ROP.
   c. Inspect, at reasonable times, any of the following:
      i. Any stationary source.
      ii. Any emission unit.
      iii. Any equipment, including monitoring and air pollution control equipment.
      iv. Any work practices or operations regulated or required under the ROP.
   d. As authorized by Section 5526 of Act 451, sample or monitor at reasonable times substances or parameters for the purpose of assuring compliance with the ROP or applicable requirements.

5. The permittee shall furnish to the department, within a reasonable time, any information the department may request, in writing, to determine whether cause exists for modifying, revising, or revoking the ROP or to determine compliance with this ROP. Upon request, the permittee shall also furnish to the department copies of any records that are required to be kept as a term or condition of this ROP. For information which is claimed by the permittee to be confidential, consistent with the requirements of the 1976 PA 442, MCL §15.231 et seq., and known as the Freedom of Information Act, the person may also be required to furnish the records directly to the USEPA together with a claim of confidentiality. **(R 336.1213(1)(e))**

6. A challenge by any person, the Administrator of the USEPA, or the department to a particular condition or a part of this ROP shall not set aside, delay, stay, or in any way affect the applicability or enforceability of any other condition or part of this ROP. **(R 336.1213(1)(f))**

7. The permittee shall pay fees consistent with the fee schedule and requirements pursuant to Section 5522 of Act 451. **(R 336.1213(1)(g))**

8. This ROP does not convey any property rights or any exclusive privilege. **(R 336.1213(1)(h))**

Equipment & Design

9. Any collected air contaminants shall be removed as necessary to maintain the equipment at the required operating efficiency. The collection and disposal of air contaminants shall be performed in a manner so as to minimize the introduction of contaminants to the outer air. Transport of collected air contaminants in Priority I and II areas requires the use of material handling methods specified in Rule 370(2). **(R 336.1370)**

10. Any air cleaning device shall be installed, maintained, and operated in a satisfactory manner and in accordance with the Michigan Air Pollution Control rules and existing law. **(R 336.1910)**

Emission Limits

11. Unless otherwise specified in this ROP, the permittee shall comply with Rule 301, which states, in part, "Except as provided in subrules 2, 3, and 4 of this rule, a person shall not cause or permit to be discharged into the outer air from a process or process equipment a visible emission of a density greater than the most stringent of the following: **(R 336.1301(1))**
    a. A 6-minute average of 20 percent opacity, except for one 6-minute average per hour of not more than 27 percent opacity.
    b. A limit specified by an applicable federal new source performance standard.

    The grading of visible emissions shall be determined in accordance with Rule 303.

12. The permittee shall not cause or permit the emission of an air contaminant or water vapor in quantities that cause, alone or in reaction with other air contaminants, either of the following:
    a. Injurious effects to human health or safety, animal life, plant life of significant economic value, or property.[1] **(R 336.1901(a))**
    b. Unreasonable interference with the comfortable enjoyment of life and property.[1] **(R 336.1901(b))**

Testing/Sampling

13. The department may require the owner or operator of any source of an air contaminant to conduct acceptable performance tests, at the owner's or operator's expense, in accordance with Rule 1001 and Rule 1003, under any of the conditions listed in Rule 1001(1). **(R 336.2001)**

14. Any required performance testing shall be conducted in accordance with Rule 1001(2), Rule 1001(3) and Rule 1003. **(R 336.2001(2), R 336.2001(3), R 336.2003(1))**

15. Any required test results shall be submitted to the Air Quality Division (AQD) in the format prescribed by the applicable reference test method within 60 days following the last date of the test. **(R 336.2001(5))**

Monitoring/Recordkeeping

16. Records of any periodic emission or parametric monitoring required in this ROP shall include the following information specified in Rule 213(3)(b)(i), where appropriate **(R 336.1213(3)(b))**:
    a. The date, location, time, and method of sampling or measurements.
    b. The dates the analyses of the samples were performed.
    c. The company or entity that performed the analyses of the samples.
    d. The analytical techniques or methods used.
    e. The results of the analyses.
    f. The related process operating conditions or parameters that existed at the time of sampling or measurement.

17. All required monitoring data, support information and all reports, including reports of all instances of deviation from permit requirements, shall be kept and furnished to the department upon request for a period of not less than 5 years from the date of the monitoring sample, measurement, report or application. Support information includes all calibration and maintenance records and all original strip-chart recordings, or other original data records, for continuous monitoring instrumentation and copies of all reports required by the ROP. **(R 336.1213(1)(e), R 336.1213(3)(b)(ii))**

Certification & Reporting

18. Except for the alternate certification schedule provided in Rule 213(3)(c)(iii)(B), any document required to be submitted to the department as a term or condition of this ROP shall contain an original certification by a Responsible Official which states that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete. **(R 336.1213(3)(c))**

19. A Responsible Official shall certify to the appropriate AQD District Office and to the USEPA that the stationary source is and has been in compliance with all terms and conditions contained in the ROP except for deviations that have been or are being reported to the appropriate AQD District Office pursuant to Rule 213(3)(c). This certification shall include all the information specified in Rule 213(4)(c)(i) through (v) and shall state that, based on information and belief formed after reasonable inquiry, the statements and information in the certification are true, accurate, and complete. The USEPA address is: USEPA, Air Compliance Data - Michigan, Air and Radiation Division, 77 West Jackson Boulevard, Chicago, Illinois 60604. **(R 336.1213(4)(c))**

20. The certification of compliance shall be submitted annually for the term of this ROP as detailed in the special conditions, or more frequently if specified in an applicable requirement or in this ROP. **(R 336.1213(4)(c))**

21. The permittee shall promptly report any deviations from ROP requirements and certify the reports. The prompt reporting of deviations from ROP requirements is defined in Rule 213(3)(c)(ii) as follows, unless otherwise described in this ROP. **(R 336.1213(3)(c))**
    a. For deviations that exceed the emissions allowed under the ROP, prompt reporting means reporting consistent with the requirements of Rule 912 as detailed in Condition 25. All reports submitted pursuant to this paragraph shall be promptly certified as specified in Rule 213(3)(c)(iii).
    b. For deviations which exceed the emissions allowed under the ROP and which are not reported pursuant to Rule 912 due to the duration of the deviation, prompt reporting means the reporting of all deviations in the semiannual reports required by Rule 213(3)(c)(i). The report shall describe reasons for each deviation and the actions taken to minimize or correct each deviation.
    c. For deviations that do not exceed the emissions allowed under the ROP, prompt reporting means the reporting of all deviations in the semiannual reports required by Rule 213(3)(c)(i). The report shall describe the reasons for each deviation and the actions taken to minimize or correct each deviation.

22. For reports required pursuant to Rule 213(3)(c)(ii), prompt certification of the reports is described in Rule 213(3)(c)(iii) as either of the following **(R 336.1213(3)(c))**:
    a. Submitting a certification by a Responsible Official with each report which states that, based on information and belief formed after reasonable inquiry, the statements and information in the report are true, accurate, and complete.
    b. Submitting, within 30 days following the end of a calendar month during which one or more prompt reports of deviations from the emissions allowed under the ROP were submitted to the department pursuant to Rule 213(3)(c)(ii), a certification by a Responsible Official which states that, "based on information and belief formed after reasonable inquiry, the statements and information contained in each of the reports submitted during the previous month were true, accurate, and complete". The certification shall include a listing of the reports that are being certified. Any report submitted pursuant to Rule 213(3)(c)(ii) that will be certified on a monthly basis pursuant to this paragraph shall include a statement that certification of the report will be provided within 30 days following the end of the calendar month.

23. Semiannually for the term of the ROP as detailed in the special conditions, or more frequently if specified, the permittee shall submit certified reports of any required monitoring to the appropriate AQD District Office. All instances of deviations from ROP requirements during the reporting period shall be clearly identified in the reports. **(R 336.1213(3)(c)(i))**

24. On an annual basis, the permittee shall report the actual emissions, or the information necessary to determine the actual emissions, of each regulated air pollutant as defined in Rule 212(6) for each emission unit utilizing the emissions inventory forms provided by the department. **(R 336.1212(6))**

25. The permittee shall provide notice of an abnormal condition, start-up, shutdown, or malfunction that results in emissions of a hazardous or toxic air pollutant which continue for more than one hour in excess of any applicable standard or limitation, or emissions of any air contaminant continuing for more than two hours in excess of an applicable standard or limitation, as required in Rule 912, to the appropriate AQD District Office. The notice shall be provided not later than two business days after the start-up, shutdown, or discovery of the abnormal conditions or malfunction. Notice shall be by any reasonable means, including electronic, telephonic, or oral communication. Written reports, if required under Rule 912, must be submitted to the appropriate AQD District Supervisor within 10 days after the start-up or shutdown occurred, within 10 days after the abnormal conditions or malfunction has been corrected, or within 30 days of discovery of the abnormal conditions or malfunction, whichever is first. The written reports shall include all of the information required in Rule 912(5) and shall be certified by a Responsible Official in a manner consistent with the CAA. **(R 336.1912)**

Permit Shield

26. Compliance with the conditions of the ROP shall be considered compliance with any applicable requirements as of the date of ROP issuance, if either of the following provisions is satisfied. **(R 336.1213(6)(a)(i), R 336.1213(6)(a)(ii))**
    a. The applicable requirements are included and are specifically identified in the ROP.
    b. The permit includes a determination or concise summary of the determination by the department that other specifically identified requirements are not applicable to the stationary source.

    Any requirements identified in Part E of this ROP have been identified as non-applicable to this ROP and are included in the permit shield.

27. Nothing in this ROP shall alter or affect any of the following:
    a. The provisions of Section 303 of the CAA, emergency orders, including the authority of the USEPA under Section 303 of the CAA. **(R 336.1213(6)(b)(i))**
    b. The liability of the owner or operator of this source for any violation of applicable requirements prior to or at the time of this ROP issuance. **(R 336.1213(6)(b)(ii))**
    c. The applicable requirements of the acid rain program, consistent with Section 408(a) of the CAA. **(R 336.1213(6)(b)(iii))**

d. The ability of the USEPA to obtain information from a source pursuant to Section 114 of the CAA. **(R 336.1213(6)(b)(iv))**

28. The permit shield shall not apply to provisions incorporated into this ROP through procedures for any of the following:
    a. Operational flexibility changes made pursuant to Rule 215. **(R 336.1215(5))**
    b. Administrative Amendments made pursuant to Rule 216(1)(a)(i)-(iv). **(R 336.1216(1)(b)(iii))**
    c. Administrative Amendments made pursuant to Rule 216(1)(a)(v) until the amendment has been approved by the department. **(R 336.1216(1)(c)(iii))**
    d. Minor Permit Modifications made pursuant to Rule 216(2). **(R 336.1216(2)(f))**
    e. State-Only Modifications made pursuant to Rule 216(4) until the changes have been approved by the department. **(R 336.1216(4)(e))**

29. Expiration of this ROP results in the loss of the permit shield. If a timely and administratively complete application for renewal is submitted not more than 18 months, but not less than 6 months, before the expiration date of the ROP, but the department fails to take final action before the end of the ROP term, the existing ROP does not expire until the renewal is issued or denied, and the permit shield shall extend beyond the original ROP term until the department takes final action. **(R 336.1217(1)(c), R 336.1217(1)(a))**

Revisions

30. For changes to any process or process equipment covered by this ROP that do not require a revision of the ROP pursuant to Rule 216, the permittee must comply with Rule 215. **(R 336.1215, R 336.1216)**

31. A change in ownership or operational control of a stationary source covered by this ROP shall be made pursuant to Rule 216(1). **(R 336.1219(2))**

32. For revisions to this ROP, an administratively complete application shall be considered timely if it is received by the department in accordance with the time frames specified in Rule 216. **(R 336.1210(9))**

33. Pursuant to Rule 216(1)(b)(iii), Rule 216(2)(d) and Rule 216(4)(d), after a change has been made, and until the department takes final action, the permittee shall comply with both the applicable requirements governing the change and the ROP terms and conditions proposed in the application for the modification. During this time period, the permittee may choose to not comply with the existing ROP terms and conditions that the application seeks to change. However, if the permittee fails to comply with the ROP terms and conditions proposed in the application during this time period, the terms and conditions in the ROP are enforceable. **(R 336.1216(1)(c)(iii), R 336.1216(2)(d), R 336.1216(4)(d))**

Reopenings

34. A ROP shall be reopened by the department prior to the expiration date and revised by the department under any of the following circumstances:
    a. If additional requirements become applicable to this stationary source with three or more years remaining in the term of the ROP, but not if the effective date of the new applicable requirement is later than the ROP expiration date. **(R 336.1217(2)(a)(i))**
    b. If additional requirements pursuant to Title IV of the CAA become applicable to this stationary source. **(R 336.1217(2)(a)(ii))**
    c. If the department determines that the ROP contains a material mistake, information required by any applicable requirement was omitted, or inaccurate statements were made in establishing emission limits or the terms or conditions of the ROP. **(R 336.1217(2)(a)(iii))**
    d. If the department determines that the ROP must be revised to ensure compliance with the applicable requirements. **(R 336.1217(2)(a)(iv))**

Renewals

35. For renewal of this ROP, an administratively complete application shall be considered timely if it is received by the department not more than 18 months, but not less than 6 months, before the expiration date of the ROP. **(R 336.1210(7))**

Stratospheric Ozone Protection

36. If the permittee is subject to Title 40 of the Code of Federal Regulations (CFR), Part 82 and services, maintains, or repairs appliances except for motor vehicle air conditioners (MVAC), or disposes of appliances containing refrigerant, including MVAC and small appliances, or if the permittee is a refrigerant reclaimer, appliance owner or a manufacturer of appliances or recycling and recovery equipment, the permittee shall comply with all applicable standards for recycling and emissions reduction pursuant to 40 CFR, Part 82, Subpart F.

37. If the permittee is subject to 40 CFR, Part 82, and performs a service on motor (fleet) vehicles when this service involves refrigerant in the MVAC, the permittee is subject to all the applicable requirements as specified in 40 CFR, Part 82, Subpart B, Servicing of Motor Vehicle Air Conditioners. The term "motor vehicle" as used in Subpart B does not include a vehicle in which final assembly of the vehicle has not been completed by the original equipment manufacturer. The term MVAC as used in Subpart B does not include the air-tight sealed refrigeration system used for refrigerated cargo or an air conditioning system on passenger buses using Hydrochlorofluorocarbon-22 refrigerant.

Risk Management Plan

38. If subject to Section 112(r) of the CAA and 40 CFR, Part 68, the permittee shall register and submit to the USEPA the required data related to the risk management plan for reducing the probability of accidental releases of any regulated substances listed pursuant to Section 112(r)(3) of the CAA as amended in 40 CFR, Part 68.130. The list of substances, threshold quantities, and accident prevention regulations promulgated under 40 CFR, Part 68, do not limit in any way the general duty provisions under Section 112(r)(1).

39. If subject to Section 112(r) of the CAA and 40 CFR, Part 68, the permittee shall comply with the requirements of 40 CFR, Part 68, no later than the latest of the following dates as provided in 40 CFR, Part 68.10(a):
    a. June 21, 1999,
    b. Three years after the date on which a regulated substance is first listed under 40 CFR, Part 68.130, or
    c. The date on which a regulated substance is first present above a threshold quantity in a process.

40. If subject to Section 112(r) of the CAA and 40 CFR, Part 68, the permittee shall submit any additional relevant information requested by any regulatory agency necessary to ensure compliance with the requirements of 40 CFR, Part 68.

41. If subject to Section 112(r) of the CAA and 40 CFR, Part 68, the permittee shall annually certify compliance with all applicable requirements of Section 112(r) as detailed in Rule 213(4)(c)). **(40 CFR, Part 68)**

Emission Trading

42. Emission averaging and emission reduction credit trading are allowed pursuant to any applicable interstate or regional emission trading program that has been approved by the Administrator of the USEPA as a part of Michigan's State Implementation Plan. Such activities must comply with Rule 215 and Rule 216. **(R 336.1213(12))**

Permit To Install (PTI)

43. The process or process equipment included in this permit shall not be reconstructed, relocated, or modified unless a PTI authorizing such action is issued by the department, except to the extent such action is exempt from the PTI requirements by any applicable rule. [2] **(R 336.1201(1))**

44. The department may, after notice and opportunity for a hearing, revoke PTI terms or conditions if evidence indicates the process or process equipment is not performing in accordance with the terms and conditions of the PTI or is violating the department's rules or the CAA. [2] **(R 336.1201(8), Section 5510 of Act 451)**

45. The terms and conditions of a PTI shall apply to any person or legal entity that now or hereafter owns or operates the process or process equipment at the location authorized by the PTI. If a new owner or operator submits a written request to the department pursuant to Rule 219 and the department approves the request, this PTI will be amended to reflect the change of ownership or operational control. The request must include all of the information required by Subrules (1)(a), (b) and (c) of Rule 219. The written request shall be sent to the appropriate AQD District Supervisor, MDEQ. [2] **(R 336.1219)**

46. If the installation, reconstruction, relocation, or modification of the equipment for which PTI terms and conditions have been approved has not commenced within 18 months of the original PTI issuance date, or has been interrupted for 18 months, the applicable terms and conditions from that PTI, as incorporated into the ROP, shall become void unless otherwise authorized by the department. Furthermore, the person to whom that PTI was issued, or the designated authorized agent, shall notify the department via the Supervisor, Permit Section, MDEQ, AQD, P. O. Box 30260, Lansing, Michigan 48909, if it is decided not to pursue the installation, reconstruction, relocation, or modification of the equipment allowed by the terms and conditions from that PTI. [2] **(R 336.1201(4))**

Footnotes:

[1]This condition is state-only enforceable and was established pursuant to Rule 201(1)(b).
[2]This condition is federally enforceable and was established pursuant to Rule 201(1)(a).

B. SOURCE-WIDE CONDITIONS

Part B outlines the Source-Wide Terms and Conditions that apply to this stationary source. The permittee is subject to these special conditions for the stationary source in addition to the general conditions in Part A and any other terms and conditions contained in this ROP.

The permittee shall comply with all specific details in the special conditions and the underlying applicable requirements cited. If a specific condition type does not apply to this source, NA (not applicable) has been used in the table. If there are no Source-Wide Conditions, this section will be left blank.

FG-FACILITY
FLEXIBLE GROUP CONDITIONS

DESCRIPTION All process equipment at the facility including equipment covered by other permits, grand-fathered equipment and exempt equipment.

Emission Units: EU-BOILER1, EU-BOILER2, EU-BOILER3, EU-BOILER4, EU-BOILER6, EU-BOILER7

POLLUTION CONTROL EQUIPMENT: Low NOx burners and flue gas recirculation for boilers No. 6 and No. 7

I. EMISSION LIMIT(S)

Pollutant	Limit	Time Period/ Operating Scenario	Equipment	Monitoring/ Testing Method	Underlying Applicable Requirements
1. HAP individual	9 tpy[2]	Rolling 12 month time period, as determined at the end of each calendar month	FG-FACILITY	SC VI.1	R336.1205(3)
2. HAPs, total	22.5 tpy[2]	Rolling 12 month time period, as determined at the end of each calendar month	FG-FACILITY	SC VI.1	R336.1205(3)
3. Sulfur dioxide (SO_2)	120 ppmv in exhaust gas (50 percent excess air)	As determined averaged over a three-hour time period or otherwise determined by the testing protocol agreed upon by AQD.	FG-FACILITY	SC II. 1. and SC V. 1.	R336.1402(4)

II. MATERIAL LIMIT(S)

1. The sulfur content of the No. 2 fuel oil and on-specification oil used in FGFACILITY shall not exceed 0.30% by weight.[2] **(R336.1402(1))**

III. PROCESS/OPERATIONAL RESTRICTION(S)

1. The permittee shall only fire natural gas, on-specification oil, or No. 2 fuel oil in EU-BOILER4.[2] **(40 CFR 52.21 (c) and (d))**

IV. DESIGN/EQUIPMENT PARAMETER(S)

1. NA

V. TESTING/SAMPLING

Records shall be maintained on file for a period of five years. **(R 336.1213(3)(b)(ii))**

1. Upon request of the AQD, verification of the SO_2 ppmv, corrected to 50% excess air emission rate from any boiler listed under FG-FACILITY when combusting distillate oil or on-specification oil, by testing at Permittee's expense, in accordance with Department requirements, will be required. No less than 30 days prior to testing, a complete test plan shall be submitted to the AQD. The final plan must be approved by the AQD prior to testing. The final plan must be approved by the AQD prior to testing. Verification of emission rates includes the submittal of a complete report of the test results to the AQD within 60 days following the last date of the test. **(R336.2001, R336.2003, R336.2004, R336.1213(3))**

See Appendix 5

VI. MONITORING/RECORDKEEPING

1. The permittee shall keep records of calculated emissions of Individual HAPs and total HAPs as required by special conditions I.1 and I.2. These emissions shall be expressed as tons per year on a rolling 12 month time period as determined at the end of each calendar month. All records shall be maintained for a period of at least five years and shall be maintained in a format acceptable to the district supervisor.[2] **(R336.1201(3))**

2. The permittee shall keep records, individually for each gas-fired boiler, of the number of hours during each calendar year that the boiler combusts liquid fuel (e.g., No. 2 fuel oil or on-specification oil) during periodic testing of boiler operation on liquid fuel or discretionary boiler operation using liquid fuel (i.e., not associated with periods of natural gas curtailment, gas supply interruption, or startups). **(R336.1213(3)(a))**

3. The permittee shall perform a daily non-certified visible emission observation of the stacks when the boilers are in use and oil is being combusted continuously for 24 hours or more. The permittee shall initiate corrective action upon observation of excessive visible emissions and shall maintain a written record of each required observation and corrective action. **(R 336.1213(3)(a)(i))**

4. The permittee shall maintain a complete record of fuel oil specifications and /or fuel analysis for each delivery, or storage tank, of fuel oil. These records may include purchase records for ASTM specification fuel oil, specifications or analyses provided by the vendor at the time of delivery, analytical results from laboratory testing, or any other records adequate to demonstrate compliance with the percent sulfur limit in fuel oil. **(R 336.1213(3)(a)(i))**

See Appendices 3, 4 and 7

VII. REPORTING

1. Prompt reporting of deviations pursuant to General Conditions 21 and 22 of Part A. **(R 336.1213(3)(c)(ii))**

2. Semiannual reporting of monitoring and deviations pursuant to General Condition 23 of Part A. The report shall be postmarked or received by the appropriate AQD's District Office by March 15 for reporting period July 1 to December 31 and September 15 for reporting period January 1 to June 30. **(R 336.1213(3)(c)(i))**

3. Annual certification of compliance pursuant to General Conditions 19 and 20 of Part A. The report shall be postmarked or received by the appropriate AQD's District Office by March 15 for the previous calendar year. **(R 336.1213(4)(c))**

See Appendix 8

VIII. STACK/VENT RESTRICTION(S)

1. NA

IX. OTHER REQUIREMENT(S)

1. If any boiler combusts liquid fuel during periodic testing of boiler operation on liquid fuel or discretionary boiler operation using liquid fuel (i.e., not associated with periods of natural gas curtailment, gas supply interruption, or startups) for greater than a combined total of 48 hours during any calendar year, the boiler will no longer be considered a "gas-fired boiler" under the definition in 40 CFR Part 63.11237. The permittee will subsequently comply with all applicable requirements under 40 CFR Part 63 Subpart JJJJJJ (the "Boiler MACT for Area Sources") for the boiler. **(40 CFR 63.11194)**

Footnotes:
[1]This condition is state only enforceable and was established pursuant to Rule 201(1)(b).
[2]This condition is federally enforceable and was established pursuant to Rule 201(1)(a).

C. EMISSION UNIT CONDITIONS

Part C outlines terms and conditions that are specific to individual emission units listed in the Emission Unit Summary Table. The permittee is subject to the special conditions for each emission unit in addition to the General Conditions in Part A and any other terms and conditions contained in this ROP.

The permittee shall comply with all specific details in the special conditions and the underlying applicable requirements cited. If a specific condition type does not apply, NA (not applicable) has been used in the table. If there are no conditions specific to individual emission units, this section will be left blank.

EMISSION UNIT SUMMARY TABLE

The descriptions provided below are for informational purposes and do not constitute enforceable conditions.

Emission Unit ID	Emission Unit Description (Including Process Equipment & Control Device(s))	Installation Date/ Modification Date	Flexible Group ID
EU-BOILER1	Boiler No. 1 - 570 million Btu/hr natural gas fired with No. 2 fuel oil backup . No Control Device	1/1/26 1/1/73	FG-BOILER_1,2, FG-FACILITY
EU-BOILER2	Boiler No. 2 - 570 million Btu/hr natural gas fired with No. 2 fuel oil backup No Control Device	1/1/26 11/20/74	FG-BOILER_1,2, FG-FACILITY
EU-BOILER3	Boiler No. 3 - 600 million Btu/hr natural gas fired with No. 2 fuel oil backup. No Control Device	1/1/59 1/1/73	FG-BOILER_3,6,7 FG-FACILITY
EU-BOILER4	Boiler No. 4 - 570 million Btu/hr natural gas and on-specification oil fired with No. 2 fuel oil backup. No Control Device	1/1/27 12/21/73	FG-BOILER_4,6,7 FG-FACILITY
EU-BOILER6	Boiler No. 6 – 180.2 million Btu/hr natural gas fired with No. 2 fuel oil backup. Boiler is equipped with low NOx burners and flue gas recirculation.	3/9/2007	FG-BOILER_6,7 FG-BOILER_3,6,7 FG-BOILER_4,6,7 FG-FACILITY
EU-BOILER7	Boiler No. 7 – 180.2 million Btu/hr natural gas fired with No. 2 fuel oil backup. Boiler is equipped with low NOx burners and flue gas recirculation.	3/9/2007	FG-BOILER_6,7 FG-BOILER_3,6,7 FG-BOILER_4,6,7 FG-FACILITY

EU-BOILER3
EMISSIONS UNIT CONDITIONS

DESCRIPTION: Boiler No. 3 - 600 million Btu/hour, natural gas fired with No. 2 fuel oil backup. Boiler No. 3 is not equipped with a control device.

Flexible Group ID: FG-BOILER_3,6,7 and FG-FACILITY

POLLUTION CONTROL EQUIPMENT None

I. EMISSION LIMIT(S)

Pollutant	Limit	Time Period/ Operating Scenario	Equipment	Monitoring/ Testing Method	Underlying Applicable Requirements
1. NOx	757.2 tons/yr[2]	Rolling 12 month time period, as determined at the end of each calendar month	EU-BOILER3	SC VI.2	40 CFR 52.21(j)
2. NOx	0.20 lb/MMBtu natural gas 0.3 lb/MMBtu distillate oil	Cumulative 5 month period May 1th through September 30th each calendar year	EU-BOILER3	SC VI.2	R336.1801(4)(b) & Table 81

II. MATERIAL LIMIT(S)

1. NA

III. PROCESS/OPERATIONAL RESTRICTION(S)

1. Permittee shall only fire natural gas and/or No. 2 fuel oil in the boiler. **(R336.1213(3))**

IV. DESIGN/EQUIPMENT PARAMETER(S)

1. NA

V. TESTING/SAMPLING

Records shall be maintained on file for a period of five years. **(R 336.1213(3)(b)(ii))**

1. NA

See Appendix 5

VI. MONITORING/RECORDKEEPING

1. Records shall be maintained on file for a period of five years. **(R336.1213(3)(b)(ii))**

2. The permittee shall maintain the following records for EU-BOILER3[2]: **(R336.1205(3))**
   a. Amount of natural gas consumed (million cubic feet), on a monthly and annual basis.
   b. Amount of No. 2 fuel oil consumed (thousands of gallons) on a monthly and annual basis
   c. Sulfur content of the No. 2 fuel oil (percent sulfur by weight).

d. Heat content of the No. 2 fuel oil in Btu's per gallon of fuel oil.
e. Calculated annual NOx emissions. NOx emissions shall be calculated for both natural gas and distillate oil combustion in accordance with the methodology contained in Appendix 7A.

3. The permittee shall calculate NOx emissions in lb/MMBtu for the cumulative 5 month period May 1st through September 30th of each calendar year. NOx emissions shall be calculated for both natural gas and distillate oil combustion in accordance with the methodology contained in Appendix 7A and 7B. **(R336.1213(3))**

See Appendices 3 and 7

VII. REPORTING

1. Prompt reporting of deviations pursuant to General Conditions 21 and 22 of Part A. **(R 336.1213(3)(c)(ii))**

2. Semiannual reporting of monitoring and deviations pursuant to General Condition 23 of Part A. The report shall be postmarked or received by the appropriate AQD's District Office by March 15 for reporting period July 1 to December 31 and September 15 for reporting period January 1 to June 30. **(R 336.1213(3)(c)(i))**

3. Annual certification of compliance pursuant to General Conditions 19 and 20 of Part A. The report shall be postmarked or received by the appropriate AQD's District Office by March 15 for the previous calendar year. **(R 336.1213(4)(c))**

See Appendix 8

VIII. STACK/VENT RESTRICTION(S)

The exhaust gases from the stacks listed in the table below shall be discharged unobstructed vertically upwards to the ambient air unless otherwise noted:

1. NA

IX. OTHER REQUIREMENT(S)

1. NA

Footnotes:
[1]This condition is state only enforceable and was established pursuant to Rule 201(1)(b).
[2]This condition is federally enforceable and was established pursuant to Rule 201(1)(a).

EU-BOILER4
EMISSIONS UNIT CONDITIONS

DESCRIPTION: Boiler No. 4 - 570 million Btu/hr, natural gas and on-specification oil fired with No. 2 fuel oil backup. Boiler No. 4 is not equipped with a control device.

Flexible Group: FG-BOILER_4,6,7 and FG-FACILITY

POLLUTION CONTROL EQUIPMENT: None

I. EMISSION LIMIT(S)

Pollutant	Limit	Time Period/ Operating Scenario	Equipment	Monitoring/ Testing Method	Underlying Applicable Requirements
1. NOx	39 tons/yr[2] (from combustion of on-spec oil)	Rolling 12 month time period, as determined at the end of each calendar month	EU-BOILER4	SC VI.2	40 CFR 52.21(j) R336.1205(3)
2.NOx	0.20 lb/MMBtu natural gas 0.3 lb/MMBtu distillate oil	Cumulative 5 month period May 1th through September 30th each calendar year	EU-BOILER4	SC VI.3	R336.1801(4)(b) & Table 81

II. MATERIAL LIMIT(S)

1. The on-specification oil combusted in EU-BOILER4 shall conform to the following specifications: **(R336.1205(3))**
   a. Arsenic, 5 ppm by weight, maximum
   b. Chromium, 9 ppm by weight, maximum
   c. Lead, 100 ppm by weight, maximum
   d. Cadmium, 2 ppm by weight, maximum
   e. Polychlorinated biphenyls, < 2 ppm by weight, maximum
   f. Beryllium, 1.8 ppm by weight, maximum
   g. Copper 100 ppm by weight, maximum
   h. Ash content, 0.16% by weight, maximum
   i. Selenium, 100 ppm, by weight, maximum
   j. Total Halogens, 1873 ppm, by weight, maximum
   k. Nickel, 59 ppm by weight, maximum

2. The on-specification oil usage in EU-BOILER4 shall not exceed 4,071 gallons per hour nor 3,240,857 gallons per rolling 12-month time period, as determined at the end of each calendar month. **(R336.1205(3))**

III. PROCESS/OPERATIONAL RESTRICTION(S)

1. All on-spec oil used in EU-BOILER4 shall comply with the requirements specified in Appendix 3A COMPLIANCE MONITORING PLAN (CMP) FOR FACILITIES BURNING ON-SPEC OIL (OSO). **(R336.1201(3))**

IV. DESIGN/EQUIPMENT PARAMETER(S)

1. NA

V. TESTING/SAMPLING

Records shall be maintained on file for a period of five years. **(R 336.1213(3)(b)(ii))**

1. NA

See Appendix 5

VI. MONITORING/RECORDKEEPING

Records shall be maintained on file for a period of five years. **(R 336.1213(3)(b)(ii))**

1. By the 10th day of each calendar month, applicant shall calculate the usage rate for each type of fuel fired in EU-BOILER4 for the previous month. This information shall be kept on file for a period of at least five years and made available to the Air Quality Division upon request[2]. **(R 336.1224(2)(b), R 336.1901, 40 CFR 279.23)**

2. The permittee shall calculate NOx emissions from EU-BOILER4 to demonstrate compliance with special condition I.1. NOx emissions shall be calculated in tons per year and based upon a rolling 12 month time period as determined at the end of each calendar month. All records shall be maintained for a period of five years and shall be in a format acceptable to the district supervisor. NOx emissions shall be calculated for on-specification oil in accordance with the methodology contained in Appendix 7A[2]. **(40 CFR 52.21(j))**

3. The permittee shall calculate NOx emissions in lb/MMBtu for the cumulative 5 month period May 1st through September 30th of each calendar year. NOx emissions shall be calculated for both natural gas and distillate oil combustion in accordance with the methodology contained in Appendix 7A and 7B. **(R336.1801(5)(a))**

See Appendices 3, 4 and 7

VII. REPORTING

1. Prompt reporting of deviations pursuant to General Conditions 21 and 22 of Part A. **(R 336.1213(3)(c)(ii))**

2. Semiannual reporting of monitoring and deviations pursuant to General Condition 23 of Part A. The report shall be postmarked or received by the appropriate AQD's District Office by March 15 for reporting period July 1 to December 31 and September 15 for reporting period January 1 to June 30. **(R 336.1213(3)(c)(i))**

3. Annual certification of compliance pursuant to General Conditions 19 and 20 of Part A. The report shall be postmarked or received by the appropriate AQD's District Office by March 15 for the previous calendar year. **(R 336.1213(4)(c))**

See Appendix 8

VIII. STACK/VENT RESTRICTION(S)

The exhaust gases from the stacks listed in the table below shall be discharged unobstructed vertically upwards to the ambient air unless otherwise noted:

1. NA

IX. OTHER REQUIREMENT(S)

1. NA

Footnotes:

[1]This condition is state only enforceable and was established pursuant to Rule 201(1)(b).
[2]This condition is federally enforceable and was established pursuant to Rule 201(1)(a).

D. FLEXIBLE GROUP CONDITIONS

Part D outlines terms and conditions that apply to more than one emission unit. The permittee is subject to the special conditions for each flexible group in addition to the General Conditions in Part A and any other terms and conditions contained in this ROP.

The permittee shall comply with all specific details in the special conditions and the underlying applicable requirements cited. If a specific condition type does not apply, NA (not applicable) has been used in the table. If there are no special conditions that apply to more than one emission unit, this section will be left blank.

FLEXIBLE GROUP SUMMARY TABLE

The descriptions provided below are for informational purposes and do not constitute enforceable conditions.

Flexible Group ID	Flexible Group Description	Associated Emission Unit IDs
FG-BOILER_1,2	Boilers No.1 and No.2	EU-BOILER1 EU-BOILER2
FG-BOILER_6,7	Boilers No.6 and No.7	EU-BOILER6 EU-BOILER7
FG-BOILER_3,6,7	Boilers No.3, No.6 and No.7	EU-BOILER3 EU-BOILER6 EU-BOILER7
FG-BOILER_4,6,7	Boilers No.4, No.6 and No.7	EU-BOILER4 EU-BOILER6 EU-BOILER7
FG-FACILITY	All process equipment at the facility including equipment covered by other permits, grand-fathered equipment and exempt equipment. FG-FACILITY is included under SOURCE-WIDE CONDITIONS.	EU-BOILER1 through 4, EU-BOILER6 EU-BOILER7

FG-BOILER_1,2
FLEXIBLE GROUP CONDITIONS

DESCRIPTION: Boiler No. 1 - 570 million Btu/hr natural gas fired with No. 2 fuel oil backup. Boiler No. 2 - 570 million Btu/hr natural gas fired with No. 2 fuel oil backup. Boiler No. 1 and Boiler No. 2 are not equipped with a control device.

Emission Units: EU-BOILER1, EU-BOILER2

POLLUTION CONTROL EQUIPMENT None

I. EMISSION LIMIT(S)

Pollutant	Limit	Time Period/ Operating Scenario	Equipment	Monitoring/ Testing Method	Underlying Applicable Requirements
1.NOx	0.20 lb/MMBtu when using natural gas	Cumulative 5 month period May 1th through September 30th each calendar year	FG-BOILER_1, 2,	SC VI.1	R336.1801(4)(b) & Table 81
2.NOx	0.3 lb/MMBtu when using distillate oil	Cumulative 5 month period May 1th through September 30th each calendar year	FG-BOILER_1, 2,	SC VI.1	R336.1801(4)(b) & Table 81

II. MATERIAL LIMIT(S)

1. NA

III. PROCESS/OPERATIONAL RESTRICTION(S)

1. Permittee shall only fire natural gas and/or No. 2 fuel oil in the boilers. **(R336.1213(3))**

IV. DESIGN/EQUIPMENT PARAMETER(S)

1. NA

V. TESTING/SAMPLING

Records shall be maintained on file for a period of five years. **(R 336.1213(3)(b)(ii))**

1. NA

See Appendix 5

VI. MONITORING/RECORDKEEPING

Records shall be maintained on file for a period of five years. **(R 336.1213(3)(b)(ii))**

1. The permittee shall calculate NOx emissions in lb/MMBtu for the cumulative 5 month period May 1st through September 30th of each calendar year. NOx emissions shall be calculated for both natural gas and distillate oil combustion in accordance with the methodology contained in Appendix 7A and 7B. **(R336.1801(5)(a))**

See Appendix 7

VII. REPORTING

1. Prompt reporting of deviations pursuant to General Conditions 21 and 22 of Part A. **(R 336.1213(3)(c)(ii))**

2. Semiannual reporting of monitoring and deviations pursuant to General Condition 23 of Part A. The report shall be postmarked or received by the appropriate AQD's District Office by March 15 for reporting period July 1 to December 31 and September 15 for reporting period January 1 to June 30. **(R 336.1213(3)(c)(i))**

3. Annual certification of compliance pursuant to General Conditions 19 and 20 of Part A. The report shall be postmarked or received by the appropriate AQD's District Office by March 15 for the previous calendar year. **(R 336.1213(4)(c))**

See Appendix 8

VIII. STACK/VENT RESTRICTION(S)

The exhaust gases from the stacks listed in the table below shall be discharged unobstructed vertically upwards to the ambient air unless otherwise noted:

1. NA

IX. OTHER REQUIREMENT(S)

1. NA

Footnotes:
[1]This condition is state only enforceable and was established pursuant to Rule 201(1)(b).
[2]This condition is federally enforceable and was established pursuant to Rule 201(1)(a).

FG-BOILER_6,7
FLEXIBLE GROUP CONDITIONS

DESCRIPTION: Boiler No. 6 – 180.2 million Btu/hr, natural gas fired with No. 2 fuel oil backup. Boiler No. 7 – 180.2 million Btu/hr, natural gas fired with No. 2 fuel oil backup. Boiler No. 6 and Boiler No. 7 are equipped with low NOx burners and flue gas recirculation.

Emission Units: EU-BOILER6, EU-BOILER7

POLLUTION CONTROL EQUIPMENT: Low NOx burners and flue gas recirculation

I. EMISSION LIMIT(S)

Pollutant		Limit	Time Period/ Operating Scenario	Equipment	Monitoring/ Testing Method	Underlying Applicable Requirement
1.1a	CO*	0.073 lb/MMBtu[2]	Test Protocol	FG-BOILER_6,7	SC V.1	40 CFR 52.21(j)
1.1b	CO**	0.155 lb/MMBtu[2]	Test Protocol	FG-BOILER_6,7	SC V.2.	40 CFR 52.21(j)
1.1c	CO	84.6 lb/hour[2]	Test Protocol and Calendar Month Average	FG-BOILER_6,7	SC V.1, SC. V.2, and SC. VI.3	40 CFR 52.21(j)
1.1d	NOx*	0.036 lb/MMBtu[2]	Test Protocol	FG-BOILER_6,7	SC V.3	40 CFR 52.21(j), 40 CFR Part 60 Section 60.44b
1.1e	NOx**	0.140 lb/MMBtu[2]	Test Protocol	FG-BOILER_6,7	SC V.3	40 CFR 52.21(j), 40 CFR Part 60 Section 60.44b
1.1f	NOx	76.4 lb/hour[2]	Test Protocol	FG-BOILER_6,7	SC V.3	40 CFR 52.21(j)
1.1g	NOx	155.3 tons/yr[2]	Rolling 12 month time period as determined at the end of each calendar month	FG-BOILER_6,7	SC VI.3	40 CFR 52.21(j)
1.1h	PM_{10}*	0.007 lb/MMBtu[2]	Test Protocol	FG-BOILER_6,7	SC V.1	40 CFR 52.21(j)
1.1i	PM_{10}**	0.040 lb/MMBtu[2]	Test Protocol	FG-BOILER_6,7	SC V.2	40 CFR 52.21(j)
1.1j	PM_{10}	21.8 lb/hour[2]	Test Protocol and Calendar Month Average	FG-BOILER_6,7	SC V.1, SC. V.2, and SC. VI.3	40 CFR 52.21(j)
1.1k	SO2	39 tons/yr[2]	Rolling 12 month time period as determined at the end of each calendar month	FG-BOILER_6,7	SC VI.2 and SC VI.3	R336.1205(3)

* This limit is applicable when burning 100% natural gas.
** This limit is applicable when burning 100% No. 2 fuel oil.

II. MATERIAL LIMIT(S)

1. NA

III. PROCESS/OPERATIONAL RESTRICTION(S)

1. Permittee shall only fire natural gas and/or No. 2 fuel oil in the boilers. **(R336.1213(3))**

2. Any No.2 Fuel Oil fired in the boilers shall have a maximum sulfur content of 0.3 percent by weight. **(40 CFR 60.42b(a))**

IV. DESIGN/EQUIPMENT PARAMETER(S)

1. NA

V. TESTING/SAMPLING

Records shall be maintained on file for a period of five years. **(R 336.1213(3)(b)(ii))**

1. Once during the term of the ROP, the permittee shall verify the CO and PM10 emission rates from FG-BOILER_6,7 when burning natural gas, by testing at owner's expense, in accordance with Department requirements. No less than 30 days prior to testing, a complete test plan shall be submitted to the AQD. The final plan must be approved by the AQD prior to testing. Verification of emission rates includes the submittal of a complete report of the test results to the AQD within 60 days following the last date of the test. **(R 336.2001, R 336.2003, R 336.2004, R336.1213(3))**

2. Once during the term of the ROP, should distillate oil be combusted in EU-BOILER6 or EU-BOILER7 for greater than 48 hours during any calendar year, the permittee shall verify the CO and PM10 emission rates from the affected boiler within FG-BOILER_6,7 when burning No. 2 fuel oil, by testing at owner's expense, in accordance with Department requirements. No less than 30 days prior to testing, a complete test plan shall be submitted to the AQD. The final plan must be approved by the AQD prior to testing. Verification of emission rates includes the submittal of a complete report of the test results to the AQD within 60 days following the last date of the test. **(R 336.2001, R 336.2003, R 336.2004, R336.1213(3))**

3. Quality assurance of the NOx predictive emission monitoring system ("PEMS") will be accomplished by performance at owner's expense of a relative accuracy test audit ("RATA") initially after PEMS installation/startup and annually thereafter, as identified in the Alternative Monitoring System Plan submitted to and approved by the Administrator. Stack testing and quality assurance procedures shall be in accordance with applicable federal Reference Methods, 40 CFR Part 60 Appendices A, B, and F. No less than 30 days prior to testing, a complete test plan shall be submitted to the AQD. The final plan must be approved by the AQD prior to testing. Verification of emission rates includes the submittal of a complete report of the test results to the AQD within 60 days following the last date of the test. **(R 336.2001, R 336.2003, R 336.2004, R336.1213(3), 40 CFR 60.49b(c)(3))**

4. Quality assurance of the NOx predictive emission monitoring system ("PEMS") will be accomplished by performance at owner's expense of a relative accuracy audit (RAA) conducted on a quarterly basis except during the quarter which the RATA is performed. Quality assurance of the NOx predictive emission monitoring system ("PEMS") will be accomplished by performance at owner's expense of a relative accuracy audit (RAA) conducted on a quarterly basis except during the quarter which the RATA is performed. Pursuant to 40 CFR Part 60, Appendix B, Performance Specification 16, if PEMS passes all quarterly RAAs in the first year and also passes the subsequent yearly RATA in the second year, the permittee may elect to perform a single mid-year RAA in place of the quarterly RAAs. This option may be repeated, but only until the PEMs fails either a mid-year RAA or a yearly RATA. When such a failure occurs, the permittee must resume quarterly RAAs in the quarter following the failure and continue conducting quarterly RAAs until the PEMs successfully passes both a year of quarterly RAAs and a subsequent RATA. **(R 336.1213(3))**

See Appendix 5

VI. MONITORING/RECORDKEEPING

Records shall be maintained on file for a period of five years. **(R 336.1213(3)(b)(ii))**

1. The permittee shall submit the date of initial startup of each boiler. This notification shall include the following: **(40 CFR Part 60 Section 60.49b(a))**
    a. The design heat input capacity of each boiler and the identification of the fuels to be combusted in the boilers.
    b. The annual capacity factor at which the permittee anticipates operating the facility, based on all fuels fired and based on each individual fuel fired.[2]
2. The permittee shall obtain and maintain fuel receipts from the fuel oil supplier which certify that the oil meets the definition of distillate oil as defined in 40 CFR Part 60 Section 60.41b. For purposes of this permit condition, the oil need not meet the fuel nitrogen content specification in the definition of distillate oil. Reports shall be submitted certifying that only very low sulfur oil meeting the definition was combusted in **FG-BOILER_6,7** during the reporting period.[2] **(40 CFR Part 60 Section 60.49b(r))**
3. The permittee shall maintain the following records for FG-BOILER_6,7:[2] **(R336.1205(3))**
    a. Amount of natural gas consumed (million cubic feet), on a monthly and annual basis.
    b. Amount of No. 2 fuel oil consumed (thousands of gallons) on a monthly and annual basis
    c. Sulfur content of the No. 2 fuel oil (percent sulfur by weight).
    d. Heat content of the No. 2 fuel oil in Btu's per gallon of fuel oil.
    e. Calculated annual sulfur dioxide and NOx emissions. Sulfur dioxide and NOx emissions shall be calculated for both natural gas and distillate oil combustion in accordance with the methodology contained in Appendix 7A. **(R336.1205(3))**
4. The permittee shall maintain records of the predicted NOx emission rates and the monitored boiler operating conditions for FG-BOILER_6,7, as identified in the Alternative Monitoring System Plan submitted to and approved by the Administrator. **(40 CFR 60.49b(c))**
5. The permittee shall calculate the pound per hour CO and PM10 emission rates, based upon a calendar monthly average, for both natural gas and distillate oil combustion in accordance with the methodology contained in Appendix 7C. **(R336.1213(3))**
6. The permittee shall keep records, individually for EU-BOILER6 and EU_BOILER7, of the number of hours during each calendar year that the boiler combusts No. 2 fuel oil under any circumstance. **(R336.1213(3))**

See Appendix 7

VII. REPORTING

1. Prompt reporting of deviations pursuant to General Conditions 21 and 22 of Part A. **(R 336.1213(3)(c)(ii))**
2. Semiannual reporting of monitoring and deviations pursuant to General Condition 23 of Part A. The report shall be postmarked or received by the appropriate AQD's District Office by March 15 for reporting period July 1 to December 31 and September 15 for reporting period January 1 to June 30. **(R 336.1213(3)(c)(i))**
3. Annual certification of compliance pursuant to General Conditions 19 and 20 of Part A. The report shall be postmarked or received by the appropriate AQD's District Office by March 15 for the previous calendar year. **(R 336.1213(4)(c))**

See Appendix 8

VIII. STACK/VENT RESTRICTION(S)

The exhaust gases from the stacks listed in the table below shall be discharged unobstructed vertically upwards to the ambient air unless otherwise noted:

Stack & Vent ID	Maximum Exhaust Dimensions (inches)	Minimum Height Above Ground (feet)	Underlying Applicable Requirements
1. SV016-026	120[2]	250	40 CFR 52.21(c) and (d)
2. SV016-027	120[2]	250	40 CFR 52.21(c) and (d)

IX. OTHER REQUIREMENT(S)

1. The permittee shall comply with applicable provisions of 40 CFR Part 60, Subpart A and Subpart Db.

Footnotes:
[1]This condition is state only enforceable and was established pursuant to Rule 201(1)(b).
[2]This condition is federally enforceable and was established pursuant to Rule 201(1)(a).

FG-BOILER_3,6,7
FLEXIBLE GROUP CONDITIONS

DESCRIPTION: Boiler No. 3 - 600 million Btu/hour, natural gas fired with No. 2 fuel oil backup. Boiler No. 3 is not equipped with a control device. Boiler No. 6 – 180.2 million Btu/hr, natural gas fired with No. 2 fuel oil backup. Boiler No. 7 – 180.2 million Btu/hr, natural gas fired with No. 2 fuel oil backup. Boiler No. 6 and Boiler No. 7 are equipped with low NOx burners and flue gas recirculation.

Emission Units: EU-BOILER3, EU-BOILER6, EU-BOILER7

POLLUTION CONTROL EQUIPMENT: Low NOx burners and flue gas recirculation for EU-BOILER6 and EU-BOILER7.

I. EMISSION LIMIT(S)

1. NA

II. MATERIAL LIMIT(S)

1. NA

III. PROCESS/OPERATIONAL RESTRICTION(S)

1. The permittee shall not operate EU-BOILER3 while either of the package boilers (EU-BOILER6 and/or EU-BOILER7) area in operation.[2] **(R336.1205(3))**

IV. DESIGN/EQUIPMENT PARAMETER(S)

1. NA

V. TESTING/SAMPLING

Records shall be maintained on file for a period of five years. **(R 336.1213(3)(b)(ii))**

1. NA

See Appendix 5

VI. MONITORING/RECORDKEEPING

Records shall be maintained on file for a period of five years. **(R 336.1213(3)(b)(ii))**

1. The permittee shall keep records, on a monthly basis, indicating the emission unit ID, the date, and the times that each boiler included in FG-BOILER_3,6,7 are in operation. This information shall be kept in a format acceptable to the district supervisor, and shall be maintained for a period of five years.[2] **(R336.1205(3))**

VII. REPORTING

1. Prompt reporting of deviations pursuant to General Conditions 21 and 22 of Part A. **(R 336.1213(3)(c)(ii))**

2. Semiannual reporting of monitoring and deviations pursuant to General Condition 23 of Part A. The report shall be postmarked or received by the appropriate AQD District Office by March 15 for reporting period July 1 to December 31 and September 15 for reporting period January 1 to June 30.[1] **(R 336.1213(3)(c)(i))**

3. Annual certification of compliance pursuant to General Conditions 19 and 20 of Part A. The report shall be postmarked or received by the appropriate AQD District Office by March 15 for the previous calendar year. **(R 336.1213(4)(c))**

See Appendix 8

VIII. STACK/VENT RESTRICTION(S)

The exhaust gases from the stacks listed in the table below shall be discharged unobstructed vertically upwards to the ambient air unless otherwise noted:

1. NA

IX. OTHER REQUIREMENT(S)

1. NA

Footnotes:
[1]This condition is state-only enforceable and was established pursuant to Rule 201(1)(b).
[2]This condition is federally enforceable and was established pursuant to Rule 201(1)(a).

FG-BOILER_4,6,7
FLEXIBLE GROUP CONDITIONS

DESCRIPTION: Boiler No. 4 - 570 million Btu/hr, natural gas and on-specification oil fired with No. 2 fuel oil backup. Boiler No. 4 is not equipped with a control device. Boiler No. 6 – 180.2 million Btu/hr, natural gas fired with No. 2 fuel oil backup. Boiler No. 7 – 180.2 million Btu/hr, natural gas fired with No. 2 fuel oil backup. Boiler No. 6 and Boiler No. 7 are equipped with low NOx burners and flue gas recirculation.

Emission Units: EU-BOILER4, EU-BOILER6, EU-BOILER7

POLLUTION CONTROL EQUIPMENT: Low NOx burners and flue gas recirculation for EU-BOILER6 and EU-BOILER7

I. EMISSION LIMIT(S)

Pollutant	Limit	Time Period/ Operating Scenario	Equipment	Monitoring/ Testing Method	Underlying Applicable Requirements
1. SO2	39 tons/yr (from burning on-spec oil in EU-BOILER4 and any fuel in EU-BOILER6, and/or EU-BOILER7[2]	Rolling 12 month time period, as determined at the end of each calendar month	FG-BOILER_4,6,7	SC VI.2	40 CFR 52.21(j) R336.1205(3)

II. MATERIAL LIMIT(S)

1. NA

III. PROCESS/OPERATIONAL RESTRICTION(S)

1. Permittee shall only fire natural gas, No. 2 fuel oil and/or on-specification oil in the boilers.[2] **((R336.1213(3))**

IV. DESIGN/EQUIPMENT PARAMETER(S)

1. NA

V. TESTING/SAMPLING

Records shall be maintained on file for a period of five years. **(R 336.1213(3)(b)(ii))**

1. NA

See Appendix 5

VI. MONITORING/RECORDKEEPING

Records shall be maintained on file for a period of five years. **(R 336.1213(3)(b)(ii))**

1. The permittee shall obtain and maintain fuel receipts from the fuel oil supplier which certify that the oil meets the definition of on-specification oil as defined in Appendix 3. For purposes of this permit condition, the oil need not meet the fuel nitrogen content specification in the definition of distillate oil. Reports shall be submitted

certifying that only very low sulfur oil meeting the definition was combusted in **FG-BOILER_4,6,7** during the reporting period. **(40 CFR Part 60 Section 60.49b(r))**

2. The permittee shall maintain the following records for FG-BOILER_4.6,7: **(R336.1213(3))**
   a. Amount of natural gas consumed (million cubic feet), on a monthly and annual basis.
   b. Amount of No. 2 fuel oil consumed (thousands of gallons) on a monthly and annual basis
   c. Amount of on-specification oil fuel oil consumed (thousands of gallons) on a monthly and annual basis
   d. Sulfur content of the No. 2 fuel oil (percent sulfur by weight).
   e. Heat content of the No. 2 fuel oil in Btu's per gallon of fuel oil.
   f. Calculated annual sulfur dioxide emissions. Sulfur dioxide emissions shall be calculated for on-specification oil combustion in accordance with the methodology contained in Appendix 7A.

See Appendices 3, 4, and 7

VII. <u>REPORTING</u>

1. Prompt reporting of deviations pursuant to General Conditions 21 and 22 of Part A. **(R 336.1213(3)(c)(ii))**

2. Semiannual reporting of monitoring and deviations pursuant to General Condition 23 of Part A. The report shall be postmarked or received by the appropriate AQD District Office by March 15 for reporting period July 1 to December 31 and September 15 for reporting period January 1 to June 30. **(R 336.1213(3)(c)(i))**

3. Annual certification of compliance pursuant to General Conditions 19 and 20 of Part A. The report shall be postmarked or received by the appropriate AQD District Office by March 15 for the previous calendar year. **(R 336.1213(4)(c))**

See Appendix 8

VIII. <u>STACK/VENT RESTRICTION(S)</u>

The exhaust gases from the stacks listed in the table below shall be discharged unobstructed vertically upwards to the ambient air unless otherwise noted:

1. NA

IX. <u>OTHER REQUIREMENT(S)</u>

1. NA

<u>Footnotes:</u>
[1]This condition is state only enforceable and was established pursuant to Rule 201(1)(b).
[2]This condition is federally enforceable and was established pursuant to Rule 201(1)(a).

E. NON-APPLICABLE REQUIREMENTS

At the time of the ROP issuance, the AQD has determined that the requirements identified in the table below are not applicable to the specified emission unit(s) and/or flexible group(s). This determination is incorporated into the permit shield provisions set forth in the General Conditions in Part A pursuant to Rule 213(6)(a)(ii). If the permittee makes a change that affects the basis of the non-applicability determination, the permit shield established as a result of that non-applicability decision is no longer valid for that emission unit or flexible group.

Emission Unit/Flexible Group ID	Non-Applicable Requirement	Justification
EU-BOILER1, EU-BOILER2, EU-BOILER3, EU-BOILER4	40 CFR Part 60, Subpart D, Standards of Performance for Fossil-Fuel-Fired Steam Generators for Which Construction is Commenced After August 17, 1971	40 CFR Part 60, Subpart D does not apply to the Boilers 1 through 4 as the change from coal burning boilers to natural gas/no.2 fuel oil boilers does not constitute as a modification as defined in §60.2. A Michigan Department of Natural Resources staff activity report dated September 23, 1975 indicates that there is a significant reduction in the majority of pollutants when changing from coal to natural gas/fuel oil. Therefore the change in fuel type did not qualify as a modification as defined under Part 60

APPENDICES

Appendix 1: Abbreviations and Acronyms

The following is an alphabetical listing of abbreviations/acronyms that may be used in this permit.

AQD	Air Quality Division	MM	Million
acfm	Actual cubic feet per minute	MSDS	Material Safety Data Sheet
BACT	Best Available Control Technology	MW	Megawatts
BTU	British Thermal Unit	NA	Not Applicable
°C	Degrees Celsius	NAAQS	National Ambient Air Quality Standards
CAA	Federal Clean Air Act	NESHAP	National Emission Standard for Hazardous Air Pollutants
CAM	Compliance Assurance Monitoring	NMOC	Non-methane Organic Compounds
CEM	Continuous Emission Monitoring	NOx	Oxides of Nitrogen
CFR	Code of Federal Regulations	NSPS	New Source Performance Standards
CO	Carbon Monoxide	NSR	New Source Review
COM	Continuous Opacity Monitoring	PM	Particulate Matter
department	Michigan Department of Environmental Quality	PM-10	Particulate Matter less than 10 microns in diameter
dscf	Dry standard cubic foot	pph	Pound per hour
dscm	Dry standard cubic meter	ppm	Parts per million
EPA	United States Environmental Protection Agency	ppmv	Parts per million by volume
EU	Emission Unit	ppmw	Parts per million by weight
°F	Degrees Fahrenheit	PS	Performance Specification
FG	Flexible Group	PSD	Prevention of Significant Deterioration
GACS	Gallon of Applied Coating Solids	psia	Pounds per square inch absolute
gr	Grains	psig	Pounds per square inch gauge
HAP	Hazardous Air Pollutant	PeTE	Permanent Total Enclosure
Hg	Mercury	PTI	Permit to Install
hr	Hour	RACT	Reasonable Available Control Technology
HP	Horsepower	ROP	Renewable Operating Permit
H_2S	Hydrogen Sulfide	SC	Special Condition
HVLP	High Volume Low Pressure *	scf	Standard cubic feet
ID	Identification (Number)	sec	Seconds
IRSL	Initial Risk Screening Level	SCR	Selective Catalytic Reduction
ITSL	Initial Threshold Screening Level	SO_2	Sulfur Dioxide
LAER	Lowest Achievable Emission Rate	SRN	State Registration Number
lb	Pound	TAC	Toxic Air Contaminant
m	Meter	Temp	Temperature
MACT	Maximum Achievable Control Technology	THC	Total Hydrocarbons
MAERS	Michigan Air Emissions Reporting System	tpy	Tons per year
MAP	Malfunction Abatement Plan	µg	Microgram
MDEQ	Michigan Department of Environmental Quality	VE	Visible Emissions
mg	Milligram	VOC	Volatile Organic Compounds
mm	Millimeter	yr	Year

*For HVLP applicators, the pressure measured at the gun air cap shall not exceed 10 pounds per square inch gauge (psig).

Appendix 2. Schedule of Compliance

The permittee certified in the ROP application that this stationary source is in compliance with all applicable requirements and the permittee shall continue to comply with all terms and conditions of this ROP. A Schedule of Compliance is not required. **(R 336.1213(4)(a), R 336.1119(a)(ii))**

Appendix 3. Monitoring Requirements

The following monitoring procedures, methods, or specifications are the details to the monitoring requirements identified and referenced in Table C-4.

Appendix 3A
COMPLIANCE MONITORING PLAN (CMP)
FOR FACILITIES BURNING ON-SPECIFICATION OIL (OSO)

A. All OSO must be acceptable for use as a fuel under federal and state on-specification oil regulations. A certificate of analysis must accompany each delivery and must be kept on file.

Each shipment from the on-spec oil supplier must be accompanied by documentation demonstrating that the on-specification oil meets specification levels in 40 CFR 279.11 (Standards for the Management of Used Oil) and R 299.9809, promulgated pursuant to Part 111, Hazardous Waste Management, of the Natural Resources and Environmental Protection Act, 1994 PA 451, as amended. The documentation shall include supplier certification and analytical data. The analysis must be for the batch of on-specification oil accepted for use as a fuel by the permittee. Separate truckloads may have identical documentation from the supplier if they are loaded from a unique batch from a single supplier. A batch is a quantity of on-specification oil contained in one storage unit (i.e., tank, tanker truck, barge, etc.) where no additional oil is put into the storage unit after testing. If additional oil is added to a storage unit after testing, a new batch has been created.

The supplier certificate of analysis shall be reviewed by the permittee to ensure that the OSO properties and constituents do not exceed any of the on-specification oil specifications contained in the following table prior to acceptance and off-loading of the shipment. This table is a combination of the regulatory levels mentioned above and site specific levels for these compounds.

TABLE 1 - ALLOWABLE LEVELS FOR OSO

Property/Constituent	Allowable Level
Higher Heating Value	17,000 Btu per pound (minimum)
Flash point	100 degrees Fahrenheit (minimum)
Arsenic	5.0 ppmw (maximum)
Cadmium	2.0 ppmw (maximum)
Chromium	9.0 ppmw (maximum)
Lead	100.0 ppmw (maximum)
Sulfur	0.3 percent (maximum)
Polychlorinated Biphenyls (PCBs)	< 2 ppmw
Total Halogens	1873 ppmw (maximum)
Ash Content	0.16% by weight (maximum)

Verification: Shipping records for each load received shall be maintained a minimum of 5 years.

B. All OSO deliveries shall be screened for halogens.

Upon receipt of each OSO fuel shipment and prior to off-loading the OSO fuel, the permittee shall obtain a representative sample according to methods described in EPA publication SW-846 "Test Methods for Evaluation Solid Waste, Physical/Chemical Methods." The sample shall be screened for Total Halogens using SW-846 Method 9077.

Verification: Records of the Total Halogens test results shall be maintained a minimum of 5 years.

C. Required Laboratory Analysis

A split sample of the OSO shall be submitted by the facility to an independent laboratory to verify the information provided on the supplier certificate of analysis for the batch in accordance with the frequency specified in section D. The laboratory analysis shall include the properties and constituents listed in Table 1. A second split sample shall be maintained by the facility until the end of the calendar year and shall be made available to the AQD upon request.

Any independent laboratory used by the facility for OSO analysis shall develop a Quality Assurance Plan (QAP). Detailed in the QAP shall be the QA/QC procedures, sample handling, storage, chain of custody procedures, analytical methods for all analyses, a description of the laboratory instrumentation, and the instrumental detection limits. The analytical methods used by the independent laboratory should be consistent with the methods identified in the OSO Supplier's Analysis Plan pursuant to 40 CFR 279.55. The facility shall maintain a copy of the approved QAP on site or at the corporate offices and be available for AQD inspection.

D. Laboratory Analysis Frequency

The laboratory analysis required in this CMP shall be completed per Method 1 and/or Method 2 as applicable.

Method 1 - Pre-Qualification: For a dedicated tank of OSO, one split sample analysis is required.

For a single batch of OSO, the laboratory analysis shall be required once prior to any shipments from that batch being received at the facility. For Method 1 pre-qualification, a batch is a quantity of OSO contained in the supplier's storage unit where no additional oil is put into the storage unit after a representative sample has been collected for analysis. If additional oil is added to the storage unit, both a new supplier certificate of analysis and laboratory analysis are necessary.

Upon receipt of a shipment of OSO, the shipping paper shall be reviewed to determine if the OSO originated from a pre-qualified batch. All OSO shipments which are not from a pre-qualified batch are required to complete the quarterly sample analysis in Method 2.

Verification: A list of OSO batches that have been pre-qualified, along with records of the OSO analytical data from both the supplier and the permittee for the same batch, shall be maintained a minimum of 5 years.

Method 2 - On-Site Qualification: For all shipments which are not a pre-qualified batch, a quarterly split sample analysis is required.

When the permittee accepts OSO that is not pre-qualified by Method 1, a minimum of one sample per calendar quarter shall be submitted for the required laboratory analysis. The quarterly sample(s) shall be selected from all OSO batches accepted by the permittee that are not pre-qualified by Method 1. Unless an alternative plan is approved by the AQD District Supervisor, the time interval between collection of samples shall be a minimum of 45 days.

<u>Fuel Oil Sulfur Monitoring</u>

Maintain a complete record of fuel oil specifications and/or fuel analysis of each delivery, or storage tank of fuel oil. These records may include purchase records for ASTM specification for fuel oil, specifications or analysis provided by the vendor at the time of delivery, analytical results from the laboratory testing, or any other records adequate to demonstrate compliance with the percent sulfur limit in fuel oil.

Appendix 4. Recordkeeping

Specific recordkeeping requirement formats and procedures are detailed in Part 3A or the appropriate Requirement Tables. In addition, the following specific records are required:

Verification: A list of all OSO batches accepted and those that have been selected for quarterly sampling, along with records of the OSO analytical data from both the supplier and the permittee for the same batch, shall be maintained a minimum of 5 years.

Verification: A list of OSO batches that have been pre-qualified, along with records of the OSO analytical data from both the supplier and the permittee for the same batch, shall be maintained a minimum of 5 years.

Verification: Records of the Total Halogens test results shall be maintained a minimum of 5 years.

Appendix 5. Testing Procedures

Specific testing requirements plans, procedures, and averaging times are detailed in the appropriate Requirement tables. Therefore, this appendix is not applicable.

Appendix 6. Permits to Install

The following table lists any PTIs issued or ROP revision applications received since the effective date of the previously issued ROP No. MI-ROP-B2814-2009. Those ROP revision applications that are being issued concurrently with this ROP renewal are identified by an asterisk (*). Those revision applications not listed with an asterisk were processed prior to this renewal.

Source-Wide PTI No MI-PTI-B2814-2009 is being reissued as Source-Wide PTI No. MI-PTI-B2814-2014.

Permit to Install Number	ROP Revision Application Number	Description of Equipment or Change	Corresponding Emission Unit(s) or Flexible Group(s)
104-12	NA	Allowance to temporarily operate Boilers 6 and 7 with their economizers bypassed for the purpose of data collection. The trial period of operation in economizer bypass mode was allowed solely for the purpose of conducting stack testing to quantify the increase, if any, of NOx emissions. This permit was voided as the trial period of operation never occurred under this permit number.	FG-BOILER_6,7
104-12A	NA	Allowance to temporarily operate Boilers 6 and 7 with their economizers bypassed for the purpose of data collection. The trial period of operation in economizer bypass mode was allowed solely for the purpose of conducting stack testing to quantify the increase, if any, of NOx emissions. This permit was voided after the trial period of operation.	FG-BOILER_6,7

Appendix 7. Emission Calculations

Specific emission calculations to be used with monitoring, testing or recordkeeping data:

Appendix 7A
Procedures for Calculating Sulfur Dioxide and NOx Emissions

Sulfur Dioxide:

The sulfur dioxide emissions shall be calculated by multiplying the amount of each fuel consumed by the appropriate emissions factor. Default emission factors to be used are: 0.6 lb/MMft^3 for natural gas, and 157*S lb per thousand gallons of oil for No.2 fuel oil and on-specification oil, where S is the sulfur content of the No.2 fuel oil (or on-specification oil) in weight percent. In the event that stack testing is performed, emission factors based on the stack testing shall be used in lieu of the default emission factors.

Nitrogen Oxides:

Annual NOx emissions shall be calculated by multiplying the amount of each fuel consumed by the appropriate emission factor. Default emission factors are indicated in the following table. In the event that stack testing is performed, emission factors based on the stack testing shall be used in lieu of the default emission factors.

Emission Unit	NOx emission factor, natural gas	NOx emission factor, oil
EU-BOILER3	280 lbs. NOx per million cubic feet of natural gas	24 lbs. NOx per 1,000 gallons of distillate oil combusted
EU-BOILER4	280 lbs. NOx per million cubic feet of natural gas	24 lbs. NOx per 1,000 gallons of distillate and on-specification oil combusted
EU-BOILER6 EU-BOILER7	37 lbs. NOx per million cubic feet of natural gas.	19.6 lbs NOx per 1,000 gallons of distillate oil.

Appendix 7B
Procedures for Calculating NOx Emissions During Ozone Control Period

If the emission limit is in the form of pounds of oxides of nitrogen per million British thermal unit, then the unit is in compliance if the sum of the mass emissions from the unit that occurred during the ozone control period (calculated per Appendix 7A), divided by the sum of the heat input from the unit that occurred during the ozone control period (calculated as the sum of the mass or volume of each fuel combusted multiplied by its respective heating value), is less than or equal to the emission limit.

Appendix 7C
Procedures for Calculating CO and PM10 Emissions

Pounds per hour CO and PM10 emissions shall be calculated on a monthly basis to demonstrate continuous compliance by multiplying the amount of each fuel consumed, by the fuel heat content, by the lb/MMBtu from stack testing, divided by the hours of operation. Emission factors from 2007 stack testing are indicated in the following table. In the event that more recent stack testing is performed, emission factors based on the most recent stack testing shall be used in lieu of emission factors provided in the following table.

Emission Unit	CO - 2007 Stack Test – Natural Gas (lb/MMBtu)	PM10 - 2007 Stack Test – Natural Gas (lb/MMBtu)	CO- 2007 Stack Test – Fuel Oil (lb/MMBtu)	PM10- 2007 Stack Test – Fuel Oil (lb/MMBtu)
EU-BOILER6	0.001	0.002	0.003	0.003
EU-BOILER7	0.003	0.002	0.001	0.008

Appendix 8. Reporting

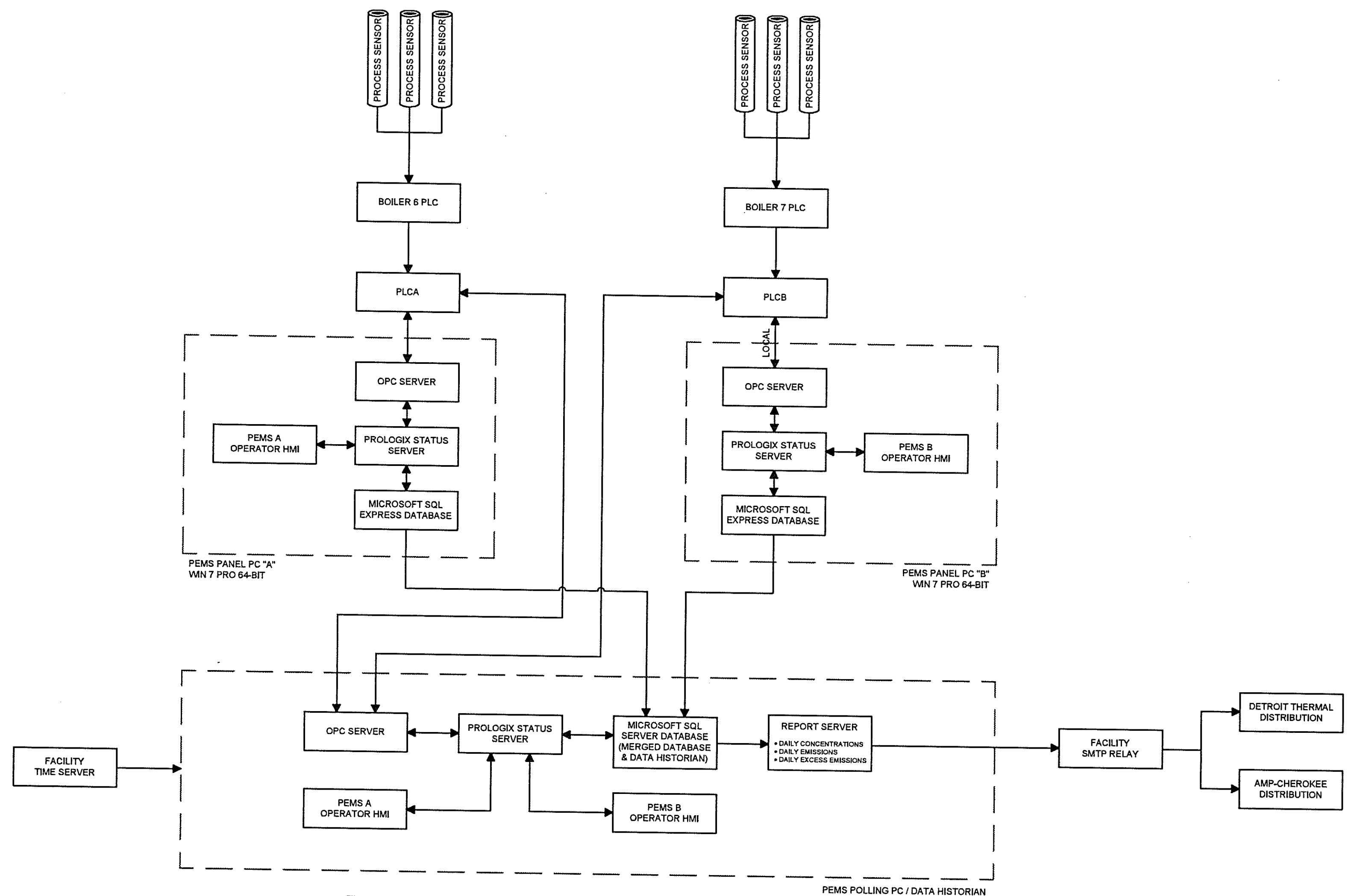
A. Annual, Semiannual, and Deviation Certification Reporting

The permittee shall use the MDEQ, AQD, Report Certification form (EQP 5736) and MDEQ, AQD, Deviation Report form (EQP 5737) for the annual, semiannual and deviation certification reporting referenced in the Reporting Section of the Source-Wide, Emission Unit and/or Flexible Group Special Conditions. Alternative formats must meet the provisions of Rule 213(4)(c) and Rule 213(3)(c)(i), respectively, and be approved by the AQD District Supervisor.

B. Other Reporting

Specific reporting requirement formats and procedures are detailed in Part A or the appropriate Source-Wide, Emission Unit and/or Flexible Group Special Conditions. Therefore, Part B of this appendix is not applicable.

APPENDIX B
DESIGN DRAWINGS



REVISIONS

REV NO.	BY	DESCRIPTION	APPROVED	DATE

DETROIT THERMAL - BEACON PLANT
541 MADISON AVENUE
DETROIT, MI 48226
USA

detroit renewable energy

AMP CHEROKEE

PROJECT NAME: BOILER 6 & 7 PEMS

PO NO: DTL-03014951

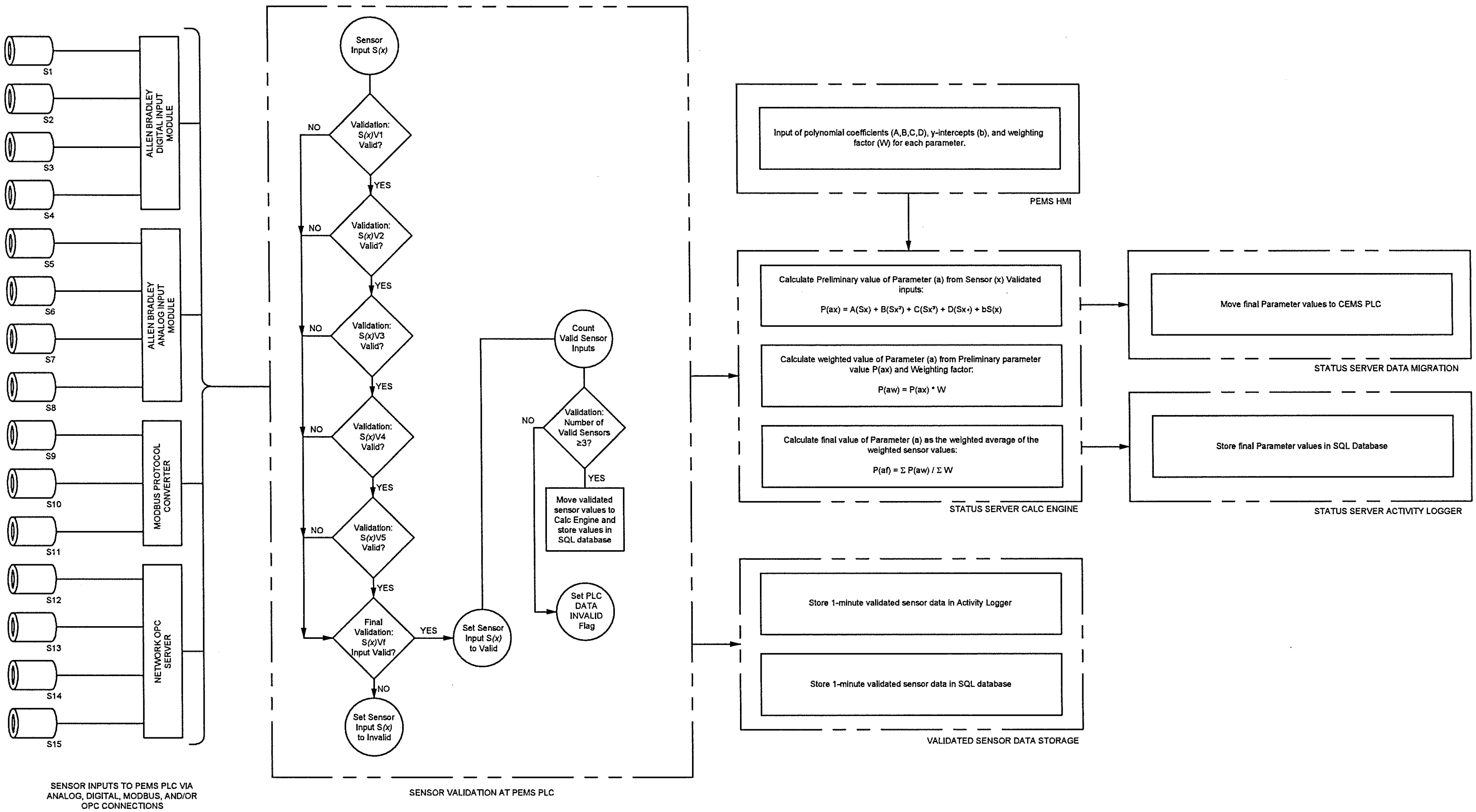
UNLESS OTHERWISE SPECIFIED DIMENSIONS ARE IN INCHES
TOLERANCES ARE:
FRACTIONS: ±1/16
DECIMALS: .X ±0.03, .XX ±0.01, .XXX±0.005
ANGLES: ±0.5°
—DO NOT SCALE DRAWING—

⚠ —REPRESENTS REVISION CHANGE

APPROVALS		DATE
DRAWN BY	MDM	07/19/16
ENGINEER	MDM	07/19/16
CHECKED	XXX	MM/DD/YY

PROLOGIX PEMS
BOILER 6 / BOILER 7/ POLLING PC
COMMUNICATIONS DIAGRAM

SIZE	SCALE	DRAWING NO.	JOB NO.	REV
B	NTS	CP104	00484	A
		CAD NO. 00484-CP104	SHEET NO. 001	



REVISIONS

REV NO.	BY	DESCRIPTION	APPROVED	DATE

DETROIT THERMAL - BEACON PLANT
541 MADISON AVENUE
DETROIT, MI 48226
USA

detroit renewable energy

AMP CHEROKEE

PROJECT NAME: BOILER 6 & 7 PEMS

PO NO: DTL-03014951

UNLESS OTHERWISE SPECIFIED DIMENSIONS ARE IN INCHES
TOLERANCES ARE:
FRACTIONS: ±1/16 DECIMALS: .X ±0.03 .XX ±0.01 .XXX±0.005 ANGLES: ±0.5°
—DO NOT SCALE DRAWING—

⚠ —REPRESENTS REVISION CHANGE

APPROVALS	DATE
DRAWN BY MDM	07/15/16
ENGINEER MDM	07/15/16
CHECKED XXX	MM/DD/YY

PROLOGIX PEMS DATA FLOW DIAGRAM

SIZE	SCALE	DRAWING NO. CP105	JOB NO. 00464	REV
B	NTS	CAD NO. 00464-CP105	SHEET NO. 001	A

Tag	CCS_PLC Tag ID	Description	Sensor Input	Boiler HMI Tag
DCS_TO_CEMS_REAL [0]	WATCHDOG_ON_DEL.ACC	Watchdog timer on 1000 ms cycle	N/A	N/A
DCS_TO_CEMS_REAL [1]	FT_X0370_EU	Fuel Gas Flow (0 to 186000) Calibrated anually	1	FT-60370
DCS_TO_CEMS_REAL [2]	FT_X4310	Steam Flow Rate (0 to 160000)	2	FT-64310
DCS_TO_CEMS_REAL [3]	FT_X2070	Combustion Air Differential Pressure (characterized Air flow without O2 trim - - 0 to 100%) Calibrated anually	3	FT-62070
DCS_TO_CEMS_REAL [4]	BE_X1300A	Flame Intensity Signal A (0 to 100%)	4	SCN A
DCS_TO_CEMS_REAL [5]	BE_X1300B	Flame Intensity Signal B (0 to 100%)	5	SCN B
DCS_TO_CEMS_REAL [6]	TT_X2600	Economizer Outlet Temperature (0 to 500 deg.)	6	TT-62600
DCS_TO_CEMS_REAL [7]	AIT_X2200	Oxygen Analyzer (0 to 25) we calibrate analyzer with Oxygen ~~[illegible]~~ anually	7	AIT-62200
DCS_TO_CEMS_REAL [8]	FT_X0370	Gas Flow Transmitter (0 to 100%)	8	FIC-60370
DCS_TO_CEMS_REAL [9]	BOILER_DEM	Boiler Demand	9	BOILER MASTER
DCS_TO_CEMS_REAL [10]	FZ_X2070	Air Damper Position (ACTUAL)	10	[NO HMI TAG]
DCS_TO_CEMS_REAL [11]	FT_X2170	Flue Gas Recirculation Flow (0 to 100%) we calibrate anually	11	FT-62170
DCS_TO_CEMS_REAL [12]	PT_X3450	Steam Header (0 to 300 PSI) [DRUM PRESSURE]	12	PT-63450
DCS_TO_CEMS_REAL [13]	FI_X2070_O2_TRIMED	Air Flow percentage with O2 trim [DIFF PRESSURE] nothing done during anual	13	[NO HMI TAG]
DCS_TO_CEMS_REAL [14]	FT_X0570_EU	Fuel Oil Flow (0 to 10000)	---	[NOT USED]
DCS_TO_CEMS_REAL [15]	FT_X3000	Feedwater Flow Rate (0 to 225000) [LB/HR]	14	FT-63000
DCS_TO_CEMS_REAL [16]	FT_X3812	Mud Drum Steam Flow (0 to 850)	15	FT-63812

Operating Or Maintenance Order

DETROIT THERMAL

EQUIP NO : 06-OPFL-BE-2006
NAME : Beacon Boiler #6
EQUIPMENT DESC :

WORK AREA : BPLT
ACTION CODE : 02
PRIORITY :
WORK ORDER DESCRIPTION :

#6 BOILER--ANNUAL--STACK FLUE GAS OXYGEN ANALYZER, TAG#--AIT-x2200, INSPECT, CLEAN, CALIBRATION, & REPAIR IF NEEDED.

Work Order No.: T103109		
Function	Resp.Code	Job No.
Requested By		Date 5/2/16
Approved By : M.H. Superintendent		5/2/16
Staff Supervisor in Charge		
Nikole A. Shift Supervisor		5/2/16
Released For Repair By: Nikole A. Supervisor in charge of Equipment		5/2/16
Completed By: J. Beppe		5-5-16
Accepted For Service By :		5/6/16
Order Completed : Shift Supervisor		5/6/16

WORK ORDER NOTES :

Protection Leader KEY PROTECTION LEADER ON SHIFT

On		RED TAG RECORD	Clear	
Time	0700	Provided By	Time	1500
Date	5-2-16		Date	5-6-16
Protection Leader			Protection Leader	
Operator			Operator	
Operator			Operator	

PROTECTION PROVIDED UNDER KEY TAGGING ORDER C-113863

Operating Or Maintenance Order

DETROIT THERMAL

EQUIP NO : 06-OPFL-BE-2006
NAME : Beacon Boiler #6
EQUIPMENT DESC :

WORK AREA : BPLT
ACTION CODE : 02
PRIORITY :
WORK ORDER DESCRIPTION :
#6 BOILER--ANNUAL--STACK FLUE GAS OXYGEN ANALYZER, TAG#--AIT-x2200, INSPECT, CLEAN, CALIBRATION, & REPAIR IF NEEDED.

Work Order No.: T103352		
Function	Resp.Code	Job No.
Requested By :		Date 5/2/16
Approved By : Superintendent		
Staff Supervisor in Charge		
Shift Supervisor		5-2-16
Released For Repair By: Supervisor in charge of Equipment		5-2-16
Completed By		5-5-16
Accepted For Service By :		5/6/16
Order Completed Shift Supervisor		5/6/16

WORK ORDER NOTES :

KEY PROTECTION
LEADER ON SHIFT

Protection Leader

On		RED TAG RECORD	Clear	
Time	0200	Provided By	Time	1500
Date	5-2-16		Date	5-6-16
Protection Leader			Protection Leader	
Operator			Operator	
Operator			Operator	

PROTECTION PROVIDED
UNDER KEY TAGGING ORDER C-113863

Operating Or Maintenance Order

DETROIT THERMAL

EQUIP NO : 06-OPFL-BE-2006

[illegible]ME : Beacon Boiler #6

[illegible]QUIPMENT DESC :

WORK AREA : BPLT

ACTION CODE : 02

PRIORITY :

WORK ORDER DESCRIPTION :

#6 BOILER--ANNUAL--FGR DIFFERENTIAL PRESSURE TRANSMITTER, TAG #FT-62170, INSPECT, CLEAN, CALIBRATION, & REPAIR IF NEEDED.

Work Order No.: T103350		
Function	Resp.Code	Job No.
Requested By : [signature]		Date 5/2/16
Approved By : [signature] M.M Superintendent		
Staff Supervisor in Charge		
[signature] Shift Supervisor		5-2-16
Released For Repair By: [signature] Supervisor in charge of Equipment		5-2-16
Completed By : [signature]		5/5/16
Accepted For Service By : [signature]		5/6/16
Order Completed : [signature] Shift Supervisor		5/6/16

WORK ORDER NOTES :

Protection Leader KEY PROTECTION LEADER ON SHIFT

On		RED TAG RECORD	Clear	
Time	0700	Provided By [signature]	Time	1500
Date	5-2-16		Date	5-7-16
Protection Leader	[signature]		Protection Leader	[signature]
Operator	[signature]		Operator	[signature]
Operator			Operator	

PROTECTION PROVIDED
PER KEY TAGGING ORDER

C-113863

Operating Or Maintenance Order

DETROIT THERMAL

EQUIP NO : 06-OPFL-BE-2006
NAME : Beacon Boiler #6
EQUIPMENT DESC :

WORK AREA : BPLT
ACTION CODE : 09
PRIORITY :
WORK ORDER DESCRIPTION :

#6 BOILER -- ANNUAL -- PG FLOOR -- COMBUSTION AIR FLOW TRANSMITTER, TAG #FT-62070, INSPECT, CLEAN, CALIBRATE (0 - 8 inH2O)

Work Order No.: T103332		
Function	Resp.Code	Job No.
Requested By:		Date 5/2/16
Approved By : M.H. Superintendent		5/2/16
Staff Supervisor in Charge		
Nikole A Shift Supervisor		5/2/16
Released For Repair By: Nikole A Supervisor in charge of Equipment		5/2/16
Completed By : J. Bene		5-5-16
Accepted For Service By :		5-8-16
Order Completed : Adam Shift Supervisor		5/8/16

WORK ORDER NOTES :

KEY PROTECTION LEADER ON SHIFT

Protection Leader

On		RED TAG RECORD	Clear	
Time	7:00	Provided By	Time	1800
Date	5-3-16		Date	5/8/16
Protection Leader			Protection Leader	Adam
Operator	Adam		Operator	
Operator			Operator	

PROTECTION PROVIDED UNDER KEY TAGGING ORDER C-113863

Operating Or Maintenance Order

DETROIT THERMAL

EQUIP NO : 06-OPFL-BE-2006
NAME : Beacon Boiler #6
EQUIPMENT DESC :

WORK AREA : BPLT
ACTION CODE : 02
PRIORITY :
WORK ORDER DESCRIPTION :

#6 BOILER--ANNUAL--NATURAL GAS MAIN LINE FLOW TRANSMITTER, TAG#--FT-60370, INSPECT, CLEAN, CALIBRATION, & REPAIR IF NEEDED. (0 - 180 inH2O)

Work Order No.: T103349	
Function / Resp.Code / Job No.	
Requested By:	Date 5/2/16
Approved By: M.M Superintendent	
Staff Supervisor in Charge	
Nikole S. Shift Supervisor	5.2.16
Released For Repair By: Nikole S. Supervisor in charge of Equipment	5.2.16
Completed By: J Bene	5-3-16
Accepted For Service By:	5-5-16
Order Completed: Shift Supervisor	5-5-16

WORK ORDER NOTES :

KEY PROTECTION

Protection Leader LEADER ON SHIFT

On	RED TAG RECORD	Clear
Time 7:30	Provided By	Time 7:33
Date 5-5-16		Date 5-5-16
Protection Leader		Protection Leader
Operator		Operator
Operator		Operator

PROTECTION PROVIDED
UNDER KEY TAGGING ORDER

Q-113863

Operating Or Maintenance Order

DETROIT THERMAL

EQUIP NO : 06-OPFL-BE-2006
ME : Beacon Boiler #6
UIPMENT DESC :

WORK AREA : BPLT
ACTION CODE : 09
PRIORITY :
WORK ORDER DESCRIPTION :

#6 BOILER -- ANNUAL -- FGR CONTROL VALVE, TAG #FCV-62170 -- CLEAN, INSPECT, CHECK OPERATION, & REPAIR IF NEEDED

Work Order No.: T103336		
Function	Resp.Code	Job No.
Requested By :		Date 5/2/16
Approved By : Superintendent		5/2/16
Staff Supervisor in Charge		
Shift Supervisor		5/2/16
Released For Repair By: Supervisor in charge of Equipment		5-2-16
Completed By :		5-4-16
Accepted For Service By :		5-5-16
Order Completed : Shift Supervisor		5-5-16

WORK ORDER NOTES :

Protection Leader KEY PROTECTION LEADER ON SHIFT

On	RED TAG RECORD	Clear
Time 8:07	Provided By	Time 7:35
Date 5-4-16		Date 5-5-16
Protection Leader		Protection Leader
Operator		Operator
Operator		Operator

PROTECTION PROVIDE
DER KEY TAGGING ORDE C-113863