B2796 - SAR - 20170808

DEPARTMENT OF ENVIRONMENTAL QUALITY
AIR QUALITY DIVISION
ACTIVITY REPORT: Scheduled Inspection

B279641799

FACILITY: ST. CLAIR / BELLE RIVER POWER PLANT		**SRN / ID:** B2796
LOCATION: 4901 POINTE DR., SAINT CLAIR		**DISTRICT:** Southeast Michigan
CITY: SAINT CLAIR		**COUNTY:** SAINT CLAIR
CONTACT: David Huxhold , Environmental Engineer		**ACTIVITY DATE:** 08/08/2017
STAFF: Francis Lim	**COMPLIANCE STATUS:** Compliance	**SOURCE CLASS:** MAJOR
SUBJECT: scheduled inspection		
RESOLVED COMPLAINTS:		

Renewable Operating Permit No. MI-ROP-B2796-2015b for St. Clair/Belle River Power Plant was renewed on July 15, 2015 and has undergone two modifications. St. Clair Power Plant (coal-fired) operates under Section 1 of the ROP. St. Clair diesel generator peakers and a combustion turbine generator peaker are covered under Section 2. Belle River Power Plant (coal-fired) operates under Section 3. Belle River diesel generator peakers and combustion turbine generator peakers are covered under Section 4 and Dean Peaking Station combustion turbine generator peakers are covered under Section 5. Reduced emissions fuel (REF) operations for Belle River Power Plant is covered under Section 6; and Section 7 for REF operations for St. Clair Power Plant.

Section 1 St. Clair Power Plant

On August 10, 2017 Robert Elmouchi and I conducted a compliance inspection at Detroit Edison St. Clair Power Plant located at 4901 Pointe Drive, China Township. Joe Neruda, environmental compliance specialist and Jason Roggenbuck, environmental engineer represented Detroit Edison.

St. Clair Power Plant consists of Units 1 to 4, 6 and 7:
No. 1 150 MW Coal fired boiler
No. 2 150 MW Coal fired boiler
No. 3 150 MW Coal fired boiler
No. 4 150 MW Coal fired boiler
No. 6 350 MW Coal fired boiler
No. 7 450 MW Coal fired boiler

The dual-turbine electrical generators have a high pressure and a low pressure turbine.

Units 1-4 utilize boilers that fire pulverized coal, but can be overfired with fuel oil No. 6 and specification used oil. Natural gas is used for boiler ignition. Fuel oil overfiring increases megawatt output normally provided by coal.

Unit 6 uses pulverized coal as primary fuel, natural gas for ignition, and fuel oil No. 2 for primary air duct heating. Unit 7 uses pulverized coal as primary fuel, and fuel oil No. 2 as auxiliary fuel. St. Clair is allowed to use a combination of western (low sulfur, high ash) and eastern (high sulfur, low ash) coal.

Unit 5 has been dismantled.

On August 11, 2016, a fire occurred at the St. Clair Power Plant. As of July 2017, only Units 1, 2, 3, and 6 are operating. Units 4 and 7 are still out of service.

EU-BOILER6-SC, EU-BOILER7-SC, FG-BOILERGEN-SC, FG-BLRS1-4-SC

On October 2015, St. Clair Power Plant shifted to specification recycled used oil (RUO) from off-specification recycled used oil. Specification used oil meets the specifications of 40 CFR 279.11, which limits arsenic, cadmium, chromium, lead, flash point, total halogens. NOTE: Off-specification RUO may be burned for energy recovery in utility boilers (40 CFR 279.61) if the used oil is not considered hazardous waste.

When RUO is delivered, Detroit Edison implements an RUO monitoring plan. Used oil generated by other Detroit Edison facilities are shipped to St. Clair. Specification RUO analysis is done (includes total Halogen and metals) before the oil is shipped out to St. Clair. If halogens exceed 1000 ppm, a halogen speciation is done. At St. Clair, used oil delivery is not accepted if no environmental staff is present and if no oil analysis accompanies the shipment. I reviewed used oil shipments and accompanying used oil analysis. Total amount of RUO delivered on-site from 2016 and 2017 will be requested from DTE.

One 1.5 million gallon tank (main fuel oil tank) stores fuel oil No. 2. Another 1.5 million gallon storage tank holds blended Fuel Oil No. 6 and recycled used oil. A sample is taken monthly from the fuel oil storage tanks and analyzed for sulfur and BTU content. There is a fuel meter for Units 6 and 7; for the other units, usage is estimated by determining the oil level in the tank. Since fuel oil No. 6 is heavier oil, temperature and viscosity is closely monitored.

All units have Low-NOx burners. Some installation of the Low-NOx burners were not considered pollution control projects, since there was a collateral increase in CO emissions (more than 100 tons per year, therefore subject to PSD).

Staff obtained a copy (attached) of the Power Plant Performance Management (PPPM) for the boilers from January to July 2017. Included in the PPPM are information about the monthly fuel usage (coal, fuel oil No. 2, blended fuel oil, natural gas), heat value, and monthly fuel oil sulfur analysis. The analysis showed that Fuel Oil No. 2 has 0.001% sulfur, and blended fuel (Fuel Oil No. 6 with RUO) has approximately 0.46% sulfur – below permit limits.

St. Clair Power Plant is subject to the Acid Rain Program and the Cross State Air Pollution Rule (CSAPR), which requires facilities to participate in an emissions trading program. CSAPR was promulgated to replace CAIR. CSAPR Phase 1 implementation started in 2015 with Phase 2 to begin in 2017.

To compute NOx and SO_2 emissions, EPA required the installation and certification of NOx and SO_2 Continuous Emissions Monitor (CEMS). Additionally, installation and certification of a CO_2 and flow monitor CEMS were required. Particulate Matter (PM) CEMS and Mercury Sorbent Tube Emission Monitoring System were also installed to comply with 40 CFR 63 Subpart UUUUU, Mercury and Air Toxics Rule (MATS Rule). A Continuous Opacity Monitor (COMS) measures the opacity from the boiler stack.

Annual CEMS Relative Accuracy Test Audit (RATA) was performed. Attached is a summary of SO2, NOx, CO2 gas RATA and flow RATA for 2016 and 2017. For 2017, only four units so far are back to service. The 2016 summary only included Units 1-4. Additional RATA results for 2016 and 2017 will be requested from DTE.

The annual COMS audit was performed during the following dates: Unit 1, June 8, 2016 and

July 12, 2017; Unit 2, June 6, 2016 and July 10, 2017, Unit 3, June 9, 2016 and July 12, 2017; Unit 4, July 13, 2016; Unit 6, June 14, 2016; and Unit 7, June 7, 2016.

The CEMS and COMS are calibrated at 7 AM every morning. Section 114a requires quarterly reporting of COMS downtime. Although St. Clair is not subject to the NSPS Subpart D (boilers were installed prior to NSPS promulgation), the ROP requires quarterly reporting of SO_2 CEMS downtime.

Quarterly COMS and CEMS downtime reports are acceptable. The following quarters have a higher than normal downtime: 2nd quarter 2015, Unit 6 COMS (4.0% downtime due to maintenance), Unit 7 COMS (1.1% downtime due to electrical and computer failure), and Unit 6 SO2 CEMS (3.5% downtime due to out-of-control calibration).

St. Clair has upgraded the air cleanup towers to better remove the moisture and installed scrubbers to improve removal of contaminants in the instrument air supplying the CEMS dilution air. The CEMS sample gas is diluted so that the sample gas will be below the dew point.

Facility keeps track of NOx CEMS downtime but is not required to report it. Facility is required to perform data substitution whenever CEMS is unavailable. Data substitution will result in higher emissions reported than what will be monitored by the CEMS.

Daily CEMS logsheet and monthly and annual maintenance checks on the CEMS are performed. These activities are performed and entered in a program called Plant View. Annunciator alarms are installed in the Control Room. If there is a CEMS alarm, control room operators will inform the CEMS technician or write a work order for the problem. There is no alarm when CEMS is auto calibrating. Attached are random CEMS Daily Logsheet, Daily Calibration Data Sheet and Calibration Gas Pressure Logsheet for the week of January 18, 2016.

St. Clair does not have a 12-month mass emission limit or hourly limit for SO_2 and NOx. An SO_2 limit of 1.67 pounds/MM BTU is required by R336.1401. Section 114a and the ROP requires that an SO_2 monthly emissions report (total pounds SO_2/total MM BTU) be submitted quarterly. The reported SO_2 emissions is calculated by dividing the total SO_2 emissions from all units divided by the total MMBTU for the month. SO_2 limit is the combined limit for all units. I verified that SO_2 monthly average is below the SO2 limit Rule 336.2170 requires quarterly reporting of opacity excess emissions. Although St. Clair reports excess opacity every quarter, AQD does not consider the excess opacity as excessive. The Startup/Shutdown Malfunction Abatement Plan for St. Clair Power Plant has been submitted and approved.

Facility was required to submit a CO Minimization Plan for all units. Operators try to achieve high combustion efficiency by monitoring furnace exit gas temperature, avoiding flame impingement (longer flame that it reaches the boiler tubes), adjusting air/fuel ratio, monitoring spark rate, position of flame. CO and O_2 analyzers are installed but are used only as operational tools. It is difficult to evaluate the effectiveness of the CO minimization plan since CO emissions are not measured by CEMS. Detroit Edison explained that the operators operate at a certain range in the CO/NOx curve where CO and NOx emissions are optimized. During the ozone season, there is special emphasis on NOx emissions, and CO may increase during this time.

In connection with the CO Minimization Plan, written records to demonstrate that CO is being minimized is now required in the ROP. The facility is complying with this requirement by recording CO minimization daily activities in a program called Pi.

CO emissions calculations based on a rolling 12-month period are required for Units 1 and 2 only. There is no CO mass emission limit. For the period ending January 2017, Unit 1 CO emissions are 119.73 tons; Unit 2 emissions are 13.55 tons. There is a big difference between Unit 1 and 2 due to the CO stack test results which was used as emission factor. ROP did not require additional CO stack tests. Attached are CO emissions records from the 12-month periods ending January 2017 to June 2017.

Particulate matter limit is verified through a PM stack test every three years. PM tests were conducted in 2004, 2007, 2010, 2013 (except for Unit 7 which was done in 2014), December 21, 2015 (Unit 1), October 10-13, 2015 (Unit 2), February 2-3, 2016 (Unit 3), December 14-16, 2015 (Unit 4), and December 8-10, 2015 (Unit 6). Because of the fire and Unit 7 still not operating, PM stack test for Unit 7 has not been done yet.

With the installation of the Chem Mod (Reduced Emissions Fuel) process, additional PM tests on the boilers were required. PM stack tests conducted in 2013 and 2015 also included a PM-10, PM-2.5 and condensibles test. The additional tests are permit-to-install requirements for the installation of the Chem Mod process and should be done every 3 years for 10 years. DTE conducted the PM tests in 2015 since they assumed that with the issuance of the ROP renewal in 2015, the PM tests were supposed to be conducted in 2015.

To assure compliance with the PM limit, proper maintenance of the ESPs is conducted. Spark rate, primary voltage and secondary amps of the ESPs are monitored and controlled. Voltage and amps are monitored in the control room, although the facility does not pay close attention to the shifting of field voltage and amps. All ESPs, except Unit 7 are over designed. Units 1-4, & 6 ESPs have a plate collection area of 750 sqft/1000 ACFM; Unit 7 has only 177. Unit 7 ESP has an SO_3 conditioning system to lower resistivity of the fly ash. However the SO_3 conditioning system was discontinued during the winter of 2015. Operation of SO_3 conditioning system is not a permit requirement. ESPs have 24 fields; 12 upper decks, and 12 lower decks. Primary voltage and secondary amps are controlled based on spark rate. The operators can choose programs on how the voltage and amps are controlled depending on the spark rate. Since Units 1 to 4 & 6 ESPs are overdesigned, the automatic controllers for the ESPs are not always programmed for optimal power. The ESP efficiency is calculated every month. ESP efficiency is calculated as more than 99%.

COMS is an indicator of ESP performance. To show ongoing compliance with the particulate matter limit, the Compliance Assurance Monitoring (CAM) Rule is required. Detroit Edison is using the COMS to comply with the PM CAM requirements. Although there is no direct correlation between opacity and PM, Detroit Edison established a correlation such that at 20% opacity and below, the PM limit is probably not exceeded. The correlation was resubmitted during the most recent ROP renewal. The semi-annual CAM reports are submitted with the ROP semi-annual report. There were no CAM excursions reported during the last 8 quarters.

FG-ASH_HAND-SC is a flexible group for the flyash collection and handling. There is a PM limit for the fly ash silo load out exhaust stacks. Weekly VE readings and proper baghouse maintenance are surrogates for verifying the PM limit. I randomly reviewed weekly VE readings. Fly ash generated by the plant is taken to the landfill. Water is added to the fly ash inspection..

Coal samples are collected on a daily basis. Coal analysis is important from an operations standpoint. Dust suppressant is added to all reserve coal piles located outdoors. The reserve is used if there is a problem with the main conveyor.

A vacuum sweeper sweeps the plant roadways daily. The vacuum sweeper is equipped with water sprays. DTE keeps a record of vacuum sweeping and water sprays.

FG-RPSPROJECT-SC is a ROP flexible group for using recovered paint solids (RPS) as supplemental fuel in Units 1-4. Usage limit is 60 tons per day, 10,000 tons per year. DTE implements a procedure for reviewing, approving and receiving RPS. Before any RPS delivery, analytical results must be reviewed by DTE Warren Service Center. Total Metals were analyzed for each shipment until a baseline data has been achieved. Titanium and Toxicity Characteristic Leaching Procedure (TCLP) analysis is done. RPS is used and mixed with coal as soon as it is delivered. There was only one delivery of RPS since 2014. DTE has stopped using RPS due to new rules regarding Commercial and Industrial Solid Waste Incineration (CISWI) MACT.

FG-COLDCLEANER-SC is a ROP flexible group for 9 cold solvent degreasers, using Zep Dyna 143, a nonhazardous solvent. An operating procedure is displayed near the cold solvent degreasers.

EU-FULTON-SC is a building heater (gas-fired 2.5 MM BTU/hr.) subject to the Major Source Industrial Boiler MACT, 40 CFR 63, Subpart DDDDD, promulgated January 31, 2014. A Burnham model building water heater that uses glycol as an additive to the water was exempted from the Boiler MACT by the US EPA. Requirements that include tune ups, one-time energy assessment, and compliance certification report submission are done. Compliance date is January 31, 2016.

FG-EMERGENS-SC is a flexible group for emergency generators subject to RICE MACT. Currently, St. Clair has only one emergency diesel generator (fire pump engine) subject to the RICE MACT. Preventive maintenance that includes tune-up and inspection (air cleaner, belts and hoses) are conducted twice a year. Tune-ups and inspections are required at least annually. The fire pump engine operated 108 hours during the August 11, 2016 fire.

FG-DSI/ACI-SC is an ROP flexible group for the MATS Compliance Project (40 CFR 63, Subpart UUUUU) for each boiler that is an electric generating unit. Dry sorbent injection (DSI) controls hydrogen chloride emissions and activated carbon injection (ACI) controls mercury emissions. MATS compliance date is April 16, 2015, but extended to April 16, 2016.

St. Clair chose to comply with the following limits: for PM, 0.03 lb/MMBTU or 0.3 lb/MW hr; for hydrogen chloride, 0.002lb/MMBTU or 0.02 lb/MW hr; and for mercury, 1.2 lb/TBTU or 0.013 lb/GW hr.

St. Clair Power Plant installed PM CEMS and mercury sorbent tube CEMS. For hydrogen chloride monitoring, the plant is conducting quarterly HCl emissions tests. St. Clair conducted HCl quarterly tests for all units for the 2^{nd} and 3^{rd}, quarter of 2016. Because of the fire and since only Unit 1, 2, 3, an 6 are back in service, only these units have completed HCL stack tests and for the 4^{th} quarter of 2016 and 1^{st} and 2^{nd} quarter of 2017. Tests showed compliance with the limit.

during the fly ash loading. There is no particulate control system installed for controlling fugitive dust from the load out area. The load out area is enclosed on three sides. The South Fly Ash Silo serves Units 1-4 while the North Fly Ash Silo serves Units 6 and 7. Method 9 VE readings are conducted on each baghouse stack a minimum of once per calendar year. See attached summary of Method 9 VE readings for 2016 and 2017.

EU-RAILCAR-SC is a ROP flexible group for the rail car coal dumper house. Eastern coal (high sulfur, low ash) is delivered by rail. The enclosed rail car coal dumper house has a PM limit for the baghouse exhaust. VE readings and proper maintenance on the baghouse are surrogates for verifying the PM limit. VE readings are required every seven days during coal dumping activity. Method 9 reading is required at least once a year during maximum routine operating conditions. I randomly reviewed weekly VE readings. See attached summary of Method 9 VE readings for 2016 and 2017.

I randomly reviewed dumper house coal throughput from February 2016 to December 2016. For that period, highest monthly coal throughput is 132,429 tons for December 2016 (limit is 220,220 tons per month). I randomly reviewed coal throughput based on a rolling 12-month average for the period January 2016 to January 2017 – monthly average throughput is below limit of 121,333 tons. DTE estimates 0.00 tons of PM emissions based on a rolling 12-month average (limit is 0.73 tons PM). PM emissions are calculated as follows: (tons coal/month) x (0.02 lbs. PM/ton coal) x (1 - 0.9974), where 0.02 is a MAERS EF and 0.9974 is the dust collector efficiency. Attached are coal throughput and PM emissions records.

FG-COALHAND-SC is a flexible group representing coal handling equipment and coal storage piles. I randomly reviewed coal handling inspection reports, and VE reading logs for stackers and transfer house dust collectors. Weekly VE readings are conducted on each vent associated with the coal handling system and from stacker drop off points. VEs are generally not expected from the transfer house dust collector exhausts, since the dust collector only operates if plant personnel are working inside the transfer house. Method 9 VE readings are conducted on each vent a minimum of once per calendar year. See attached summary of Method 9 VE readings for 2016 and 2017.

All conveyor belting is totally enclosed to control particulate fallout except for the following: the conveyor system for the stacker/reclaimer (not covered and not completely enclosed); and some other conveyors between transfer houses or crushers (covered but not completely enclosed). Detroit Edison explained that these older conveyors, including some conveyors between transfer houses and crushers, are not part of the Phase I coal handling equipment which was covered under PTI No. 7-75 (issued June 19, 1987). NOTE: Phase I coal handling equipment was built in conjunction with the construction of Belle River Power Plant to support the combustion of western low sulfur coal for both St. Clair and Belle River. Furthermore, Detroit Edison explained that the conveyor serving the stacker/reclaimer cannot be enclosed because the stacker/reclaimer moves along the coal conveyor. All conveyors used for transferring coal to St. Clair or Belle River are enclosed, except the above-described coal conveyors.

The coal storage piles supplies both St. Clair and Belle River Power Plants. The storage piles are located at the Belle River side but handled by St. Clair. Majority of the coal is stored below ground. 90% of the coal arrives by boat (western, low to mid sulfur); 10% arrives by railcar (eastern, mid to high sulfur). During unloading of coal by boat, water sprays are utilized at the drop off and transfer points. The boat dock is located at the St. Clair side. A copy of the Fugitive Dust Control Program for the boat unloading was submitted during the previous

PM CEMS PS-11 correlation tests for all St. Clair boilers were conducted in 2016. Annual relative response audit (RRA) for 2017 has been done only for Unit 1, 2, 3, and 6.

Annual mercury STMS RATA was done for all units in 2016. Only Unit 1, 2, 3, and 6 have completed the mercury STMS RATA for 2017.

St. Clair reported a mercury exceedance for Unit 2 from June 17-29, 2016. A Notice-of-Violation was issued.

The following records must be kept at the facility: each occurrence and duration of each startup and or/shutdown; records of occurrence and duration of each malfunction of an operation or air pollution control and monitoring equipment; records of actions taken during periods of malfunction to minimize emissions; and records of types and amounts of fuel used during each startup or shutdown. Staff will verify if these records are being kept.

FG-ISLANDS-SC is an ROP flexible group for the DSI and ACI sorbents storage. PM limits for the storage silos with bin vent filters or dust collectors are complied with by proper maintenance on the dust collectors, implementing a malfunction abatement plan for the process and emission controls, and performing daily VE readings. A Method 9 VE reading is required at least once a year. VE reading and Method 9 VE observation records will be requested from DTE.

FG-MATSPROJECT-SC is an ROP flexible group for the DSI and ACI emissions control systems. This flexible group requires an A-A emissions calculations of PM, PM10, CO2 and CO2e. The A-A emission calculation records are to be submitted only if the calendar year combined actual emissions of either PM, PM10, CO2 and CO2e exceed the baseline actual emissions by a significant amount, and the calendar year combined actual emissions differ from the preconstruction projection.

The Notification of Compliance for the MATS Rule (mercury, PM, and HCl) was received on July 27, 2016 (Unit 1), July 29, 2016 (Unit 2), July 27, 2016 (Unit 3), July 27, 2016 (Unit 4), August 2, 2016 (Unit 6) and August 2, 2016 (Unit 7).

Section 2 St. Clair Peakers

This section is for the St. Clair Peaking Station consisting of a 23 MW natural gas-fired turbine generator (installed in 1968) and two (2) 2.75 MW diesel generator. These peakers are seldom used. The most recent event where these peaking units were run continuously was during the blackout in the summer of 2003.

FG-MACT-ZZZZ-SP is a flexible group for the two diesel generator peakers. Fuel oil No. 2 that is used for the diesel peakers come from same main fuel oil storage tank used for St. Clair Unit 6 and 7. Diesel generators are run and tested every month.

The two diesel peakers have recently been retrofitted with catalytic oxidizers to comply with the RICE MACT 40 CFR 63 Subpart ZZZZ. Performance testing of catalyst oxidation control is required every three years. Performance testing was conducted May 2013 and January 2016.

Pressure drop across the oxidation catalyst did not change by more than 2 inches of water at 100% load plus or minus 10% from the pressure drop across the catalyst that was measured during the initial performance test. Temperature of the inlet to catalyst is monitored. See attached differential pressure and temperature records.

DTE reported a deviation for the Dynalco catalyst monitor not correctly calculating the 4-hour rolling average of the operating data obtained from CPMS.

EU-CTG11-1-SP is a 23 MW natural gas-fired grandfathered combustion turbine generator. Only pipeline quality natural gas is used as fuel.

AQD will follow up whether an open crankcase filtration emission control system was installed.

AQD will follow up if DTE is implementing the Continuous Parameter Monitoring System and Start up, Shutdown Malfunction Plan.

On August 9, 2017, I conducted an inspection at Detroit Edison Belle River Power Plant located at 4505 King Road, China Township. Dave Huxhold is the environmental engineer assigned at the facility.

Section 3 Belle River Power Plant

On August 8 and 9, 2017, Robert Elmouchi and I conducted an inspection at Detroit Edison Belle River Power Plant located at 4505 King Road, China Township. Dave Huxhold is the environmental engineer assigned at the facility.

Belle River Power Plant consists of two base-load, Babcock and Wilcox radiant reheat coal-fired boilers with electric-generating capacity rated at 625 MWG (Unit 1) and 635 MWG (Unit 2). The boilers were installed in 1978 and use low sulfur western pulverized coal as primary fuel, with fuel oil No. 2 for overfiring (fuel oil overfiring results in more megawatt output than what is normally provided by coal). Since fuel oil is more expensive than coal, fuel oil overfiring is only done to supplement coal when a coal mill is down or when coal feed is not at maximum.

A Chem Mod process (Reduced Emissions Fuel) was installed in 2009 to reduce SO_2 and mercury emissions.

FG-BOILERS-BR

Staff obtained a copy of the Power Plant Performance Management (PPPM) for the Belle River boilers from January - July 2017. The following information is included: monthly fuel usage, heat value, and monthly fuel oil sulfur analysis. A certificate of fuel oil analysis accompanies each fuel oil shipment. Fuel oil is sampled monthly from the fuel oil storage tank. Coal and fuel oil analysis showed 0.34% and 0.001% sulfur content, respectively. There are no fuel usage limits for the boilers.

Belle River Power Plant is subject to Acid Rain and Cross State Air Pollution Rule (CSAPR). Both programs require facilities to participate in an emission trading program and install continuous emissions monitor (CEMS).

The NOx and SO_2 CEMS can display instantaneous, 1-hr average or 3-hr average NOx and SO_2 emissions. The CEMS can show real-time display, real-time history, and real-time trend to predict if an exceedance will occur. Particulate Matter (PM) CEMS and Mercury Sorbent Tube Emission Monitoring System were also installed to comply with the Mercury and Air

Toxics (MATS) Rule.

Belle River is subject to NSPS Subpart D. SO_2 limit is 1.2 pounds/MM BTU, based on a 3-hr average. NOx limit is 0.70 pound/MM BTU, based on a 3-hr average. Compliance with the limits was initially verified during the performance tests. Belle River does not have a 12-month mass emission limit for SO_2 and NOx.

NSPS subpart D requires quarterly reporting of NOx and SO_2 excess emissions based on exceedances of a three hour average, as determined from CEMS.

Quarterly reports of NOx and SO_2 excess emissions (3-hr average) are acceptable from 1st quarter 2015 until 1st quarter 2017. Monitor downtime frequency are acceptable for the same period. The following quarter has a higher than normal downtime: Unit 1 SO2 CEMS, 2.9% downtime, 1st quarter 2016 due to analyzer failure. Additionally, Section 114a and the ROP requires that an SO_2 monthly emissions report (total pounds SO_2/total MM BTU) be submitted quarterly. The reported SO_2 emissions is calculated by dividing the total SO_2 emissions from all units divided by the total MMBTU for all units for the month.

Rule 336.2170 requires quarterly reporting of opacity excess emissions. Although there are opacity excess emissions as reported from the 1st quarter 2015 until 1st quarter 2017, AQD does not consider the opacity exceedances as excessive. COMS downtime frequency is acceptable for the same period.

The CEMS and COMS are calibrated every morning. CEMS calibration lasts about 25 minutes. A CEMS checklist is completed twice a week. Routine maintenance checks on the CEMS are done and entered in Plant View. Dilution air cleaning filters and drying agents are replaced annually. Flow monitor filters or transducers were inspected April 11, 2017. Maintenance and malfunction logs of the CEMS can be viewed on Plant View.
Attached is a snapshot of Unit 1 and 2 CEMS Log that lists activities conducted on the CEMS.

Blowback is performed on sampling system twice a day. CEMS/COMS annunciator alarm panels are installed in the Control Room. The audible alarm system warns plant staff when an exceedance has occurred or if CEMS/COMS are down. There is no alarm when CEMS/COMS are auto calibrating. Control Room operator can verify what the problem is and inform the technician or write a work order. During the inspection, an updated QA/QC Plan for the CEMS/COMS was submitted. DTE is working on a newer version to include the new PM and Mercury CEMS in the QA/QC Plan.

For Unit 1, Gas RATA was done April 27, 2017; 5-year 3-load Flow RATA test, May 12, 2017; and COMS Audit, July 19, 2017. Linearity test was done on February 15, 2017, April 12, 2017, and July 12, 2017. For Unit 2, Gas RATA was done April 25, 2017; Flow RATA, February 10, 2017; and COMS Audit, July 20, 2017. Linearity test was done February 08, 2017, April 13, 2017, and July 13, 2017. See attached summary.

Facility was required to submit a CO Minimization Plan for Units 1 and 2 during the installation of the Low-NOx burners. Since CO emissions are not monitored, it is difficult to evaluate the effectiveness of the CO Minimization Plan. CO and O_2 analyzers are installed only as an operational tool for the operator.

Written records of activities to demonstrate that CO is being minimized are required in the ROP. In Plant View, control room operators record the options that were done to minimize emissions on a daily basis. Options to minimize CO emissions are: adjust O_2 percentage; maintain proper fuel-to-air ratio; visually monitor combustion conditions; tested coal mill fineness; measured unburned carbon in ash; and determine proper control settings. Excess O_2 at the boiler is maintained at approximately 3.5%. See attached CO Minimization Actions for Unit 1 and 2 for July 19-26, 2017.

There is no CO mass emission limit for the boilers. PTI 164-08B requires the calculation of CO emissions for Unit No. 1 only. Unit 1 CO emissions based on a rolling 12-month period will be requested from DTE. Unit 1 CO annual stack test is also required by PTI No. 164-08B. For 2016, testing was done on September 8, 2016.
The date for the 2017 CO stack test will be requested from DTE.

PM limit compliance is verified through a PM stack test conducted every three years. PM stack tests were done in 2010, 2013, November 23-25, 2015 (Unit 1) and September 28-30, 2015 (Unit 2). PM limit is ensured by proper maintenance of the ESPs. Spark rate and resistivity of the ESPs are monitored and controlled. Voltage and amps are monitored in the control room, although the facility does not pay close attention to the shifting of field voltage and amps. Higher amps is desired but not to the point of sparking. COMS is an indicator of proper ESP performance. To comply with the particulate matter Compliance Assurance Monitoring Rule (CAM), COMS is used as an indicator for continuous compliance with the particulate matter limit. Although there is no direct correlation between opacity and PM, Detroit Edison established a correlation such that at 20% opacity and below, the PM limit is probably not exceeded. Detroit Edison submitted a new correlation during the recent ROP renewal. Detroit Edison has reported and certified that there were no CAM excursions from January 2016 until the 1^{st} quarter of 2017.

With the installation of the Chem Mod (Reduced Emissions Fuel) process, additional PM tests on the Unit 1 and Unit 2 boilers were required. PM stack tests conducted in 2013 and 2015 also included a PM-10, PM-2.5 and condensibles test. The additional tests are permit-to-install requirements for the installation of the Chem Mod process and should be done every 3 years for 10 years. DTE conducted the PM tests in 2015 since they assumed that with the issuance of the ROP renewal in 2015, the PM tests were supposed to be conducted in 2015.

The ESPs have 48 TR sets and 6 fields. The operating parameters of Units 1 and 2 ESPs are electronically recorded; hence the operator does not log them daily. DTE implements a Monthly Precipitator Transformer Inspection Log for Unit 1 and 2.

The S/S/M Abatement Plan for Belle River Power Plant Boiler No. 1 and No. 2 and the Preventative Maintenance and Malfunction Abatement Plan for Belle River ESPs (dated August 30, 2011, Rev 4) were submitted on August 31, 2011. This is a requirement of the ROP.

FG-AUXBLRS-BR is a flexible group for the auxiliary boilers. Belle River has 2 auxiliary boilers, north and south, fired with No. 2 fuel oil. These units are seldom used. The auxiliary boilers are subject to the Major Source Boiler MACT promulgated on January 31, 2013. The aux boilers are complying as a limited-use boiler.

The oil-fired boilers use fuel oil No. 2 with a sulfur content of 0.001%. A fuel meter is installed for each boiler. A transmitter accuracy test for the fuel flowmeters were conducted March 20, 2015; December 2, 2016 and June 19, 2017.

Visible emissions readings are only required if the auxiliary boilers operate continuously for 24 hours or more. Attached is a log of Daily Aux Boiler Opacity Run Time Log and Aux Boiler Run Hours Log.

Average capacity factor for 2016 is 0.55 for the North aux boiler and 0.88 for the South aux boiler. Capacity factor Boiler MACT limit for a limited use boiler is 10%.

Tune up requirements, one-time energy assessment, and Boiler MACT compliance certification reporting were completed.

FG-ASH_HAND-BR is a flexible group for the flyash collection and handling. There is a PM limit for the fly ash silo load out. VE readings and proper implementation of flyash loading procedure are surrogates for the PM limit. Unit 1 fly ash silo can load railcars (not presently used) or trucks; Unit 2 fly ash silo can only load trucks. Ash is wet loaded from both silos. Unit 2 fly ash silo is equipped with a Vaculoader spout for dry loading to minimize emissions. The spout is maintained under negative pressure – air is drawn into a filter section. During vaculoading of ash, one of the hatches in the truck has to be left open so that the operator can see the level inside the truck. For wet loading, a mixer combines water with the fly ash. To further minimize dust during wet loading water sprays are used. Fly ash goes to a landfill.

Belle River is required to conduct weekly VE readings during fly ash loading from each silo. DTE personnel conduct VE readings of fugitive emissions coming out of the load out structure. AQD staff verified that records of VE readings are maintained, and if the operator notices fugitive emissions, it is logged, and a comment is entered. Attached are random Visible Emissions Log from January to July 2017. In 2009, Unit 2 load out structure was lengthened to minimize fugitive emissions coming from the structure.

A procedure for fly ash unloading has been submitted and reviewed by staff. A Fugitive Fly Ash Dust Control Program was submitted on August 12, 2009.

Paved roadways inside the facility, including the roadway surrounding the ash load out silos are vacuum swept as needed. Water sprinklers and water trucks with sprays are operated as needed. Calcium chloride is also applied to the plant roadways. See attached calcium chloride application records.

FG-COALHAND-BR represent coal handling at Belle River. The following emission units make up the coal handling flexible group: transfer houses, coal silos, and cascades. Transfer houses are larger buildings; cascades are smaller buildings. All conveyors used for transferring coal to the boilers are enclosed, minimizing fugitive coal dust emissions. VE readings are conducted every week and logged for each vent associated with the coal handling system. I reviewed logs and verified that readings are conducted weekly. VE readings are from the dust collector exhaust. The dust collectors are only operated whenever there are personnel working inside the cascades or transfer houses. I reviewed the weekly VE reading logs. Attached are copies of VE logs for the week of August 6, 2017.

The main coal storage piles supplies both St. Clair and Belle River Power Plant. The storage piles are located at Belle River but handled by St. Clair. Radial stackers are manually adjusted to limit free fall distance. A bulldozer continuously compacts the storage piles to prevent fugitive dust. In addition to the main coal pile, a reserve pile is also maintained by Belle River for its use. Dust suppressant is added to the reserve piles.

FG-COLDCLEANER is a flexible group for cold cleaners. Belle River Power Plant has only 1 cold cleaner left, located at the maintenance shop. It uses a Zep Dyna 143 parts cleaner – a nonhazardous solvent. An operating procedure is displayed near the cold solvent degreaser.

FG-EMERGENS-BR is a flexible group for emergency generators subject to RICE MACT. Belle River has only one emergency diesel generator (fire pump engine) subject to the RICE MACT. A tune-up and inspection (air cleaner, belts, and hoses) were conducted on December 27, 2016 and July 25, 2017. Tune-ups and inspection are required at least annually. The diesel engine has operated approximately one hour in 2017 for testing. See attached maintenance records.

FG-DSI/ACI-BR is an ROP flexible group for the MATS Compliance Project (40 CFR 63, Subpart UUUUU) for each boiler that is an electric generating unit. Dry sorbent injection (DSI) controls hydrogen chloride emissions and activated carbon injection (ACI) controls mercury emissions. MATS compliance date is April 16, 2015, but extended to April 16, 2016.

Belle River chose to comply with the following limits: for PM, 0.03 lb/MMBTU or 0.3 lb/MW hr; for hydrogen chloride, 0.002lb/MMBTU or 0.02 lb/MW hr; and for mercury, 1.2 lb/TBTU or 0.013 lb/GW hr.

Belle River Power Plant installed PM CEMS and mercury sorbent tube monitoring system (STMS). For hydrogen chloride monitoring, the plant is conducting quarterly HCl emissions tests. Belle River Unit 1 and 2 conducted HCl quarterly tests for the 2nd, 3rd, and 4th quarter of 2016, and for the 1st and 2nd quarter of 2017. Tests showed compliance with the limit.

PS-11 correlation tests for Unit 1and 2 PM CEMS were conducted in June 6-8, 2016 and March 1-2, 2016, respectively. Annual relative response audit (RRA) for Unit 1 (March 2, 2017) and Unit 2 (May 2, 2017) PM CEMS were done.

Annual Mercury STMS RATA was done on February 9-10, 2016 and February 1-3, 2017 for Unit 1; February 23-24, 2016 and February 27-March 1, 2017 for Unit 2.

The following records must be kept at the facility: each occurrence and duration of each startup and or/shutdown; records of occurrence and duration of each malfunction of an operation or air pollution control and monitoring equipment; records of actions taken during periods of malfunction to minimize emissions; and records of types and amounts of fuel used during each startup or shutdown. Staff will verify if these records are being kept.

FG-ISLANDS-BR is an ROP flexible group for the DSI and ACI sorbents storage. PM limits for the storage silos with bin vent filters or dust collectors are complied with by proper maintenance on the dust collectors, implementing a malfunction abatement plan for the process and emission controls, and performing daily VE readings. I randomly reviewed daily VE readings. A Method 9 VE reading is required at least once a year. See attached Method 9 records.

FG-MATSPROJECT-BR is an ROP flexible group for the DSI and ACI emissions control systems. This flexible group requires an A-A emissions calculations of PM, PM10, CO2 and CO2e. The A-A emission calculation records are to be submitted only if the calendar year combined actual emissions of either PM, PM10, CO2 and CO2e exceed the baseline actual emissions by a significant amount, and the calendar year combined actual emissions differ from the preconstruction projection. Attached are Unit 1 and 2 2016 emissions for PM, PM10,

CO_2 and CO_2e for Unit 1 and 2.

The Notification of Compliance for the MATS Rule (mercury, PM, and HCl) was received on August 18, 2016 (Unit 1) and July 29, 2016 (Unit 2).

<u>Section 4 Belle River Peakers</u>

This section is for the five (5) diesel peaking units (2.5 MW each) and three (3) 82.4 MW peaking combustion turbine generators.

FG-DIESEL-BP is a flexible group for five peaking diesel generators. Fuel oil used in the diesel engines is the same oil used at the Belle River main boilers. The diesel engines are tested monthly. The diesel engines have not run continuously for more than 24 hours, therefore no VE readings have been conducted. The diesel engines, subject to RICE MACT are classified as limited use engines. RICE MACT limited use engines has a limit of 99 hours of operation per calendar year. Run hours for all 5 engines will be requested from DTE.

FG-CTG-BP is a flexible group for three natural gas-fired combustion turbine generator peakers. The combustion turbines are subject to Acid Rain and Cross State Air Pollution Rule (CSAPR). Both programs require facilities to participate in an emission trading program and install continuous emissions monitor (CEMS). The Belle River combustion turbine generators' Acid Rain Permit is included with the Belle River Power Plant Acid Rain Permit.

To comply with the Acid Rain and CSAPR Program, the facility is allowed to install PEMS (Predictive Emissions Monitoring System) instead of CEMS because the turbines are considered peakers. Since natural gas is the only fuel used, only a NOx PEMS is required. To calculate SO_2 emissions, Part 75 Appendix D allows use of the SO_2 emissions default value of 0.0006 lb/MM BTU for natural gas.

The combustion turbine generators' rating is dependent on ambient temperature. In the winter, the CTGs can generate more than 82.4 MW and in the summer, less than 82.4 MW. The turbines were installed in 2001 and are subject to NSPS Subpart GG.

Most startups for the simple cycle combustion turbines are "cold" starts. Normal startup consists of the following steps: primary mode, lean-lean mode, secondary mode, and premix mode. Premix mode has optimized emissions. It takes 23 minutes to reach premix mode from cold start. A motor is needed to spin the turbine during startup. Steady state turbine speed is 3600 RPM. At 60% steady state turbine speed, the motor is no longer needed to spin the turbine. It takes 20 minutes for a controlled shutdown of the turbine. During a controlled shutdown, fuel firing is stopped at 20% steady state turbine speed.

In calculating the NSPS NOx standard (limit), an allowance for fuel bound nitrogen is allowed. Since fuel bound nitrogen is negligible in natural gas, Detroit Edison is not required to monitor nitrogen content if Detroit Edison prefers not to use the nitrogen allowance to comply with the NOx emission limit (Oct 13, 1999 EPA letter to Detroit Edison). NSPS no longer requires implementation of sulfur custom fuel monitoring plan if pipeline quality natural gas is used as fuel.

The NOx PEMS monitor the following parameters: turbine megawatts, fuel flow, exhaust temperature, compressor discharge temperature, pitch or inlet guide vanes opening (controls combustion air), and compressor discharge pressure. Only 4 of those parameters (DTE chose guide vane pitch angle, compressor discharge temperature, compressor discharge pressure, and exhaust temperature) are required to be maintained within a specified range.

Detroit Edison chose to monitor and maintain within a given range, the following 4 parameters: guide vane pitch angle, compressor discharge temperature, compressor discharge pressure and exhaust temperature. Whenever one or more of the four turbine QA/QC operating parameters is continuously exceeded for one or more successive operating periods totaling 16 unit operating hours, NOx emission rate is required to be retested. Attached is a record of the parameter ranges for the CTGs.

Records indicating number of consecutive hours when the operating parameter ranges were exceeded will be requested from DTE.

NOx emission rate and NOx mass emissions have to be determined to comply with the NSPS and emissions trading program. NOx emissions are calculated hourly, based on turbine load. Note: NOx emissions-turbine load correlation is not constant, but varies depending on a given turbine load. Part 75 appendix E requires a NOx emission rate test once every 20 calendar quarters. The results of the NOx testing are incorporated in the PEMS. NOx mass emissions are calculated using the DAHS (data acquisition and handling system).

CO testing is done in conjunction with NOx testing. PM-10 testing is conducted every 5 years (ROP requirement). CO and PM-10 mass emissions are calculated using the worst case emission factors obtained from the most recent stack tests.

The CTGs were tested for NOx and CO in 2007, 2012, June 1-2, 2017 (CTG12-1), June 7-8, 2017 (CTG12-2) and June 10, 2017 (CTG 13-1). The PM-10 stack test was conducted in May and June, 2017.

Compliance with the NOx and CO ppm limit and PM-10 pounds/hour limit have been demonstrated during the most stack test.

The ROP summary report of emission values (for the 12-month period ending in June 2017) for the CTGs is attached. The summary report (for each turbine) includes the following information: total amount of the natural gas used; NOx, CO, and PM emissions; startup/shutdown hours; and capacity factor. Information submitted shows compliance with the limits. Certified VE readings for the three turbines were conducted in May and June 2017. See attached records.

A quarterly visual inspection of the CTG silencer is required. Silencers were repacked with new insulation in June/July of 2010. Attached is a record of 2017 silencer inspections for the combustion turbine generators.

Major work, including any turbine replacement has not yet been done to the combustion turbines.

Generally, combustion tuning is not done for the CTGs. Air fuel ratio is automatically set.

Section 5 Dean Peaking Station

FG-CTG-DP is a flexible group for four (4) 82.4 MW peaking combustion turbine generators operated by Dean Peaking Station (formerly DTE Energy Services, a subsidiary of the Detroit Edison Company).

The combustion turbine generators are subject to Acid Rain and Cross State Air Pollution

Rule (CSAPR). Both programs require facilities to participate in an emission trading program and install continuous emissions monitor (CEMS). The turbines were installed in 2002 and are subject to NSPS Subpart GG.

To comply with the Acid Rain and CSAPR, the facility is allowed to install PEMS instead of CEMS because the turbines are considered peakers. PEMS is a predictive emissions monitoring system. Since natural gas is the only fuel, only a NOx PEMS is required. To calculate SO_2 emissions, Part 75 Appendix D allows use of the SO_2 emissions default value of 0.0006 lb/MM BTU for natural gas.

These combustion turbine generators are identical to the combustion turbine generators in Section 4. Most startups "cold" starts. They follow the same normal startup which consists of the following steps: primary mode, lean-lean mode, secondary mode, and premix mode. Premix mode has optimized emissions. The combustion turbine generators' rating is also dependent on ambient temperature. In the winter, the CTGs can generate more than 82.4 MW and in the summer, less than 82.4 MW.

In calculating the NSPS NOx standard (limit), an allowance for fuel bound nitrogen is allowed. Since fuel bound nitrogen is negligible in natural gas, Detroit Edison is not required to monitor nitrogen content if Detroit Edison prefers not to use the nitrogen allowance to comply with the NOx emission limit. NSPS no longer requires implementation of sulfur custom fuel monitoring plan if pipeline quality natural gas is used as fuel.

The NOx PEMS monitor the following parameters: turbine megawatts, fuel flow, exhaust temperature, compressor discharge temperature, pitch or inlet guide vanes opening (controls combustion air), and compressor discharge pressure. Only 4 of those parameters (DTE chose guide vane pitch angle, compressor discharge temperature, compressor discharge pressure, and exhaust temperature) are required to be maintained within a specified range.

Since the Dean Peakers are similar to the Belle River combustion turbines, Detroit Edison chose to monitor and maintain within a given range, the same 4 parameters: guide vane pitch angle, compressor discharge temperature, compressor discharge pressure and exhaust temperature. Whenever one or more of the four turbine QA/QC operating parameters is continuously exceeded for one or more successive operating periods totaling 16 unit operating hours, NOx emission rate is required to be retested. The parameter ranges are the same as the ranges for the Belle River CTGs.,

Records indicating number of consecutive hours when the operating parameter ranges were exceeded will be requested from DTE.

NOx emission rate and NOx mass emissions have to be determined to comply with the NSPS and emissions trading program. NOx emissions are calculated hourly, based on turbine load. NOx emissions-turbine load correlation is not constant, but varies depending on a given turbine load. NOx emissions calculations are done through the DAHS .(data acquisition and handling system).

CO, PM-10 and HCOH mass emissions are calculated using the worst case emission factors obtained from the most recent stack tests. NOx testing is done every 20 calendar quarters. CO testing is done in conjunction with the NOx testing. PM-10 testing is done every 5 years. The results of the NOx testing are incorporated in the PEMS. The CTGs were tested for NOx and CO in 2007, 2012, June 13-14, 2017 (CTG 11-1), June 15-16, 2017 (CTG 11-2), June 21-22, 2017 (CTG 12-1), and June 19-20, 2017 (CTG 12-2). PM-10 stack tests were conducted on June 6, 2017 (CTG 11-1), June 7, 2017 (CTG 11-2), June 19, 2017 (CTG 12-1), and June 15, 2017 (CTG 12-2).

Compliance with the PM-10, NOx and CO ppm limit was demonstrated during the most recent stack tests. HCOH emission factors were developed from the previous stack test. The HCOH stack test is only a one-time test.

The summary of emission values for ROP for the CTGs for the 12-month periods ending in January to December 2016 is attached. The attached report (for all units) is the summary record that includes the following information: total amount of the natural gas used; NOx, CO, HCOH and PM emissions; startup and shutdown hours; and peak and base load operating hours. Capacity factor for each turbine will be requested from DTE. Records submitted show compliance. Certified VE readings for the three turbines were conducted in July 2017. See attached records.

Generally, combustion tuning is not done for the CTGs. Air fuel ratio is automatically set. Major work, including any turbine replacement has not yet been done to the combustion turbines.

<u>Section 6 Huron Fuels Company, LLC</u>

FG-REF-BRFC is a flexible group for the refined coal production system. The Huron Fuels Company, LLC (formerly Belle River Fuels Company) operates the Chem Mod process (Reduced Emissions Fuel) at the Belle River Power Plant. Chem Mod process is designed to control SO_2 (using S-Sorb) and mercury (using liquid Mer Sorb). S-Sorb is cement kiln dust (CKD) while Mer Sorb is calcium bromide. Both additives (0.32% S-Sorb and 0.002% Mer Sorb, by weight) are added to the coal before being fired at the boilers. The additive concentrations are adjusted as necessary to optimize emissions control. Unit 2 boiler used to have some slagging problems with Chem Mod use. To minimize slag accumulation, DTE requested AQD (approved) to allow MgOH to be injected in the boiler.

There is a PM, PM10 and PM2.5 limit for the various dust collectors for the reduced emissions process. Stack testing was not required to verify emissions. Proper maintenance of the dust collectors and VE readings are surrogates for the stack test. VE readings are conducted on a daily basis whenever the refined coal production system is operating. I randomly reviewed daily VE readings. Method 9 readings are only required if visible emissions are observed. Facility conducts monthly inspection of the Chem Mod process and equipment to identify anything that could cause air emissions. Attached are Environmental Inspection Checklist conducted on July 20, 2017 and a monthly activity report for June 2017.

I randomly reviewed and obtained a copy (attached to this report) of rolling 12-month usage (ending in May and June 2017) of refined coal, S-Sorb and Mer Sorb and daily usage of pre-REF coal, S-Sorb and Mer-Sorb. Usage is below 12-month rolling and daily limits.

The Chem Mod process requires the submission of an updated Belle River Power Plant Fugitive Dust Control Program and a Malfunction Abatement Plan for the Chem Mod Process. These were submitted on September 7, 2010.

The ROP requires DTE to submit Annual Emission Analysis Report that compares yearly actual emissions to baseline actual and projected actual emissions. The baseline actual and projected annual emissions are emissions before and after the Chem Mod process was installed. The annual reports were submitted on March 2, 2017, March 1, 2016, March 11, 2015, March 3, 2014, February 28, 2013, February 29, 2012, and February 28, 2011. The PSD A-A calculation is required to be submitted for the first year that the Chem Mod is operational. A-A calculations shall be maintained for 10 years and made available to AQD upon request. The permit section analyzes the validity of the A-A calculations.

With the installation of the Chem Mod process, additional PM tests on Belle River Power Plant Unit 1 and Unit 2 boilers were required. PM stack tests conducted in 2013 and 2015 also included a PM-10, PM-2.5 and condensibles test.

Section 7 St. Clair Fuels Company, LLC

FG-REF-SCFC is a flexible group for the refined coal production system. The St. Clair Fuels Company, LLC operates the Chem Mod process (Reduced Emissions Fuel) at the St. Clair Power Plant. Chem Mod process is designed to control SO_2 (using S-Sorb) and mercury (using liquid Mer Sorb). S-Sorb is cement kiln dust (CKD) while Mer Sorb is calcium bromide. Both additives (0.32% S-Sorb and 0.22% Mer Sorb, by weight) are added to the coal before being fired at the boilers. The additive concentrations are adjusted as necessary to optimize emissions control.

There is a PM, PM10 and PM2.5 limit for the various dust collectors for the reduced emissions process. Stack testing was not required to verify emissions. Proper maintenance of the dust collectors and VE readings are surrogates for the stack test. VE readings are conducted on a daily basis whenever the refined coal production system is operating. I randomly reviewed daily VE readings. Method 9 readings are only required if visible emissions are observed. Facility conducts monthly inspection of the Chem Mod process and equipment to identify anything that could cause air emissions.

I randomly reviewed and obtained a copy (attached to this report) of rolling 12-month usage (ending in January, February, March, April, May and June 2017) of refined coal, S-Sorb and Mer Sorb. Usage is below 12-month rolling limits. I randomly reviewed the rest of the usage records, including daily usage of pre-REF coal, S-Sorb and Mer-Sorb at the plant.

The Chem Mod process requires the submission of an updated St. Clair Power Plant Fugitive Dust Control Program. The updated program was submitted on September 9, 2010.

The ROP requires DTE to submit Annual Emission Analysis Report that compares yearly actual emissions to baseline actual and projected actual emissions. The baseline actual and projected annual emissions are emissions before and after the Chem Mod process was installed. The annual reports were submitted on March 2, 2017, March 1, 2016, March 11, 2015, March 3, 2014, Feb 28, 2013, February 29, 2012 and Feb 28, 2011. T. The PSD A-A calculation is required to be submitted for the first year that the Chem Mod is operational. A-A calculations shall be maintained for 10 years and made available to AQD upon request. The permit section analyzes the validity of the A-A calculations.

With the installation of the Chem Mod process, additional PM tests on all St. Clair boilers were required. PM stack tests conducted in 2013 and 2015 also included a PM-10, PM-2.5 and condensibles test.

NAME [signature] DATE 09-29-17 SUPERVISOR [signature]