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

B279631260

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: Joseph Neruda , Environmental Specialist		**ACTIVITY DATE:** 07/01/2015
STAFF: Francis Lim	**COMPLIANCE STATUS:** Compliance	**SOURCE CLASS:** MAJOR
SUBJECT:		
RESOLVED COMPLAINTS:		

Renewable Operating Permit No. MI-ROP-B2796-2015 for St. Clair/Belle River Power Plant was renewed on July 15, 2015. 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 DTE Energy Services combustion turbine generator peakers are covered under Section 5. Reduced emissions fuel (REF) operations for St. Clair Power Plant is covered under Section 6; and Section 7 for REF operations for Belle River Power Plant.

St. Clair Power Plant

On July 1, 2015 I conducted a compliance inspection at Detroit Edison St. Clair Power Plant located at 4901 Pointe Drive, China Township. Joe Neruda, environmental compliance specialist, Jason Roggenbuck, environmental engineer and Steve Down, environmental supervisor represented Detroit Edison. Chris Ethridge (Supervisor, AQD) and Maggie Pallone (Legislative Affairs Director, DEQ) were also present during the inspection.

Section 1 St. Clair Power Plant

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 turbine generators consist of 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 off-specification used oil (blended with fuel oil no. 6). Fuel oil overfiring increases megawatt output normally provided by coal. Boiler ignition is with natural gas. Off-specification recycled used oil (RUO) does not meet the specifications of 40 CFR 279.11, which limits arsenic, cadmium, chromium, lead, flash point, total halogens. Facility only monitors the halogen and PCB content of the RUO to verify that the off-specification RUO is not considered hazardous waste. Off-specification RUO may be burned for energy recovery in utility boilers (40 CFR 279.61) if it is not considered hazardous waste.

St. Clair does not have a permit to burn off-specs used oil. Detroit Edison claims that burning off-specs used oil is a grandfathered operation. The plant has been using it since before 1968. AQD agreed that although a permit application was submitted for the Low-NOx burners for Units 1-4, the Low-NOx installation did not change the "grandfathered" status of the process of combusting off-specs used oil. When RUO is delivered, Detroit Edison implements an off-specs RUO monitoring plan. This plan has been reviewed by the AQD. Used oil generated by other Detroit Edison facilities are shipped to St. Clair. Since the RUO is considered off-specs, no metals analysis is done. Halogen analysis is done 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. Attached is a summary of RUO shipments for 2014 and 2015.

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.

One 5-million gallon tank (main fuel oil tank) stores fuel oil No. 2. One 1.5 million gallon storage tank holds blended Fuel Oil No. 6 and 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. Low-NOx burners are no longer considered pollution control projects, since there is a collateral increase in CO emissions (more than 100 tons per year, therefore PSD subject).

Staff obtained a copy of the Power Plant Performance Management (PPPM) for the boilers from June 2014 to May 2015. Included in the PPPM are information about the monthly fuel usage (coal, fuel oil No. 2, fuel oil No. 6, used 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 Clean Air Interstate Rule (CAIR), which requires facilities to participate in an emissions trading program. 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 is also required. A Continuous Opacity Monitor (COMS) measures the opacity from the boiler stack. Cross State Air Pollution Rule (CSAPR) was promulgated to replace CAIR. On August 21, 2012, the Court of Appeals ruled that the EPA's Cross State Air Pollution Rule (CSAPR) violated the Clean Air Act, citing that the rule exceeded the agency's statutory authority. This leaves CAIR in place. On October 23, 2014, DC Circuit court granted EPA's appeal to lift CSAPR stay. CSAPR Phase 1 implementation is now scheduled for 2015 with Phase 2 beginning in 2017. The ROP will be reopened to remove CAIR and replace it with CSAPR.

Annual CEMS Relative Accuracy Test Audit (RATA) was performed for all units: Unit 1 gas RATA, 03/28/2014; Unit 3 gas RATA, 03/12/2014; Unit 3 flow RATA, 03/18/2014; Unit 4 flow RATA, 03/20/2014; Unit 2 flow RATA, 03/24 & 03/25/2014; Unit 2 gas RATA, 03/27/2014; Unit 4, gas RATA, 04/01/2014; Unit 7 gas RATA, 09/15/2014; Unit 7 flow RATA, 09/16/2014;

Unit 1 flow RATA, 09/25/2014; Unit 6 gas RATA, 10/31/2014; Unit 7 gas RATA, 12/10/2014; Unit 6 flow RATA, 12/17/2014.

The annual COMS audit was performed during the following dates: Unit 1, 06/12/2014; Unit 2, 06/09/2014; Unit 3, 06/11/2014; Unit 4, 06/10/2014; Unit 6, 08/01/2014 and Unit 7, 07/25/2014.

The CEMS and COMS are calibrated at 7 AM every morning. Section 114a requires quarterly reporting of COMS downtime. NSPS Subpart D requires quarterly reporting of NOx and SO2 CEMS downtime. St. Clair is not subject to the NSPS Subpart D since the boilers were installed prior to NSPS promulgation. However, the ROP requires quarterly reporting of SO_2 CEMS downtime.

Quarterly COMS and CEMS downtime report is acceptable, except for the following periods: 2nd quarter 2015, Unit 6 (4.0% COMS DT due to COMS maintenance) and Unit 6 (3.5 % SO2 CEMS DT due to calibration – out of control); 4th quarter 2014, Unit 4 (2.4% SO2 CEMS DT due to out of control during calibration); 3rd quarter 2014, Unit 7 (3.1% COMS DT due to lightning strike); 2nd quarter 2014, Unit 7 (2.7% COMS DT due to hardware failure).

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 checklist and monthly and annual maintenance checks on the CEMS are performed. A daily checklist log is no longer recorded manually. The checklist is 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 is a list of events, including maintenance and audits conducted on the CEMS and COMS.

St. Clair does not have a 12-month mass emission limit or hourly limit for SO_2 and NOx. An SO_2 limit of 0.80 pound/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 limit has not been exceeded. 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. NOTE: The USEPA included opacity violations in their July 24, 2009 NOV sent to St. Clair and Belle River Power Plant.

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. When NOx goes down, typically CO goes up. Detroit Edison claims 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.

Unit 1 CO emissions for the 12-month period ending May 2013 are 204.1 tons; for Unit 2 emissions are 27.0 tons. There is a big difference due to CO stack test results which was used as emission factor. There is no CO mass emission limit. CO emissions calculations are required for Units 1 and 2 only. Attached is a record of CO emissions calculations.

Particulate matter limit is verified through a PM stack test every three years. PM tests were conducted in 2004, 2007, 2010, and 2013 (except for Unit 7 which was done in 2014). NOTE: In addition to PM, a test for PM-10 and PM-2.5 (or condensibles) is required every three years, for ten years by PTI No. 176-09.

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 (the SO_3 conditioning system was discontinued during the winter of 2015. Operation of SO_3 conditioning system is not a permit condition 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 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.

There is a PM limit for the fly ash silo load out. VE readings are a surrogate for the PM limit. VE readings for the silos were reviewed. Fly ash generated by the plant is either sold as concrete binder or taken to the landfill. Water is added to the fly ash during the fly ash loading if the fly ash is going to the landfill. If the fly ash will be sold for concrete manufacturing, the fly ash is loaded dry. There is no particulate control system installed for controlling dust from the load out area. The load out area is enclosed on all three sides. The South Fly Ash Silo serves Units 1-4 while the North Fly Ash Silo serves Units 6 and 7. Attached is a record of VE readings for the flyash silos loadout.

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. During the inspection, AQD staff observed a boat unloading coal. There were no visible emissions. Attached is a copy of the Fugitive Dust Control Program.

Eastern coal (high sulfur, low ash) is delivered by rail. The rail car coal dumping facility has a PM limit. VE readings are a surrogate for 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 reviewed VE and Method 9 readings. 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. For the period July 2014 until June 2015, highest monthly coal throughput is 74,335 tons for October 2014 (limit is 220,220 tons per month); coal throughput based on a rolling 12-month average is 35,722 tons (limit is 121,333 tons); and 0.001 tons PM based on a rolling 12-month average (limit is 0.73 tons PM). Attached is a record of VE readings and emissions calculations for the rail car coal dumping facility.

I reviewed coal handling inspection reports, and VE reading logs from stackers and transfer house dust collectors. Coal handling emission points are separated into two groups, Daily Dust Patrol 1 and Daily Dust Patrol 2. 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. See attached VE readings records.

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.

A vacuum sweeper sweeps the plant roadways daily. The vacuum sweeper is equipped with water sprays.

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.

PTI No. 176-09 was issued August 2, 2010 for the addition of the Chem Mod process (also known as reduced emissions fuel, or REF). 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. The additives are added to the coal before being fed to the boilers. Plant operators can control which units can burn treated coal.After some tweaking, they have reduced the concentration of the additives (0.32% S-Sorb and 0.22% Mer Sorb, by weight) but still achieve the same emission reduction. Usage of the S-Sorb and Mer Sorb is below daily limits. 12-month rolling total for the period ending in December 2014 for Pre-Chem Mod coal, S-Sorb, and Mer Sorb are below limits and as follows: 1,516,277 tons, 4,951 tons, and 318 tons respectively. Daily VE readings and monthly environmental inspections are done. On Sep 9, 2010, an updated Fugitive Dust Control Program for St. Clair (to include Chem Mod) was submitted, as required by the permit. Attached is a record of material usage and emissions calculations for the REF.

The Chem Mod PTI requires DTE to submit Annual Emission Analysis Reports that compares annual actual emissions to baseline actual and projected actual emissions for St. Clair Power Plants – all units. Another report compares annual actual emissions to baseline actual and projected actual emissions for St. Clair and Belle River Power Plant – all units. The reports were submitted March 11, 2015, March 3, 2014, Feb 28, 2013, February 29, 2012 and Feb 28, 2011. The permit section is responsible for analyzing the validity of the calculations.

PTI No. 89-10 is for the use of biodiesel as fuel in Unit 7. A PSD A-A calculation is required to be submitted for the first year that biodiesel fuel is used in Unit 7. A-A calculations shall be maintained for 10 years and made available to AQD upon request. As of the date of inspection, biodiesel has not been used as fuel in Unit 7.

PTI No. 133-11A is a permit 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. There was only one delivery of RPS from January 2014 until June 2015. For the 12-month rolling time period ending in June 2015, RPS delivered was 16.1 tons. 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. At this time, only titanium and Toxicity Characteristic Leaching Procedure (TCLP) analysis is done. Attached is a record of RPS deliveries. Note: RPS is used and mixed with coal as soon as it is delivered.

St. Clair has 9 cold solvent degreasers, using Zep Dyna 143, a nonhazardous solvent. An operating procedure is displayed near the cold solvent degreasers.

Two building heaters (gas-fired 2.5 MM BTU/hr, and 1.9 MM BTU/hr No. 2 fuel oil-fired) are potentially subject to the Major Source Industrial Boiler MACT, 40 CFR 63, Subpart DDDDD, promulgated January 31, 2014. However, one of the heaters, a Burnham model that uses glycol as an additive to the water was exempted by the US EPA. Requirements include tune ups, one-time energy assessment, and compliance certification reporting. Compliance date is January 31, 2016.

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.

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. A deviation report was submitted for the Dynalco catalyst monitor not correctly calculating the 4-hr rolling average of the operating data obtained from CPMS.

Belle River Power Plant

On September 17, 2015, 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

Belle River Power Plant consists of two base-loaded, 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, for instance when a coal mill is down and coal feed is not at maximum.) A certificate of fuel oil analysis accompanies each fuel oil shipment. Fuel oil is sampled monthly from the fuel oil storage tank. A Chem Mod process (Reduced Emissions Fuel) has been installed in 2009 to reduce SO_2 and mercury emissions.

Staff obtained a copy of the Power Plant Performance Management (PPPM) for the boilers from September 2014 - August 2015. The following information is included: monthly fuel usage (coal and fuel oil No. 2), heat value, and monthly fuel oil sulfur analysis. Fuel oil analysis showed 0.001% sulfur content. There are no fuel usage limits for the boilers.

Belle River Power Plant is subject to the Acid Rain and Clean Air Interstate Rule (CAIR). The ROP was reopened and reissued on March 14, 2011 to incorporate the CAIR Sulfur Dioxide (SO_2) Budget Permit, CAIR Ozone Nitrogen Oxide (NOx) Budget Permit, and CAIR Annual NOx Budget Permit. Both programs require facilities to participate in an emissions trading program. Cross State Air Pollution Rule (CSAPR) has replaced CAIR. The recently issued ROP will be reopened to remove CAIR and replace it with CSAPR.

The 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.

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 for the last 8 quarters. On July 3 and 4, 2011 the 3-hr SO_2 emissions limit was exceeded for more than 2 hours for both Unit 1 and Unit 2 when a high sulfur eastern coal was left in the Krupp pile and mistakenly sent to the plant. A NOV was issued to the facility.

Monitor downtime has been acceptable except for the 2nd quarter 2013 for Unit 2, 2.1% NOx CEMS due to CO2 monitor 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. SO_2 limit is a combined limit for all units. AQD staff verified that average monthly SO_2 emission is in compliance with this limit.

Rule 336.2170 requires quarterly reporting of opacity excess emissions. Although there are opacity excess emissions as reported in the semi-annual reports, AQD does not consider the opacity exceedances as excessive. NOTE: The USEPA included opacity violations in their July 24, 2009 NOV sent to Detroit Edison St. Clair/Belle River Power Plant. COMS downtime is acceptable from April 2011 until March 2013.

The CEMS and COMS are calibrated at 7 AM every morning. Daily CEMS checklist is completed and monthly and annual maintenance checks on the CEMS are done (entered in Plant View). Blowback is performed on sampling system twice a day. CEMS/COMS annunciator alarms are installed in the Control Room. The audible alarm system warns plant staff when an exceedance has occurred or if CEMs/COMS is 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. Facility has submitted a QA/QC program for the CEMS and COMS.

For Unit 1, Gas RATA was done May 6, 2015; Flow RATA, May 8, 2015; COMS Audit, May 13, 2015. For Unit 2, Gas RATA was done May 14, 2015; Flow RATA, April 16, 2015; COMS Audit, May 20, 2015. Maintenance and malfunction logs of the CEMS can be viewed on Plant View.

Facility was required to submit a CO Minimization Plan for Units 1 and 2 during the installation of the Low-NOx burners. Unit 1 installation of the Low-NOx burners was covered by PTI No. 164-08, which was later modified to PTI No. 164-08B with the installation of the Chem Mod process. Since CO emissions are not monitored, it is difficult to evaluate the effectiveness of the CO Minimization Plan. When NOx goes down, normally CO goes up. During the ozone season, there is special emphasis on NOx reduction, meaning CO will tend to increase during this time. CO and O_2 analyzers are installed only as an operational tool for the operator.

There is no CO mass emission limit for the boilers. PTI 164-08B requires the calculation of CO emissions for Unit No. 1 only. But since the CO emissions are based on EF (lbs./MM BTU) the CO emissions calculation does not really determine the effectiveness of the CO Minimization Plan.

Reported CO emissions from Unit 1 are 98.9 tons based on a rolling 12-month period ending July 2015. Basis for this is the results of a CO stack test conducted on August 11-13, 2014.

The CO annual stack test is required by PTI No. 164-08B for Unit 1 only. Testing for this year was done August 10-12, 2015. Attached is a record of CO emissions for Unit 1.

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 September 9 – 17, 2015.

PM limit compliance is verified through a PM stack test conducted every three years. PM stack tests were done on August 3-6, 2010 and July 15-19, 2013. 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 2014 until the second quarter of 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. Attached is an August 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.

PTI 164-08B was issued March 9, 2010 with the addition of the Chem Mod process(Reduced Emissions Fuel). 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 are added (0.32% S-Sorb and 0.002% Mer Sorb, by weight) to the coal before being fed to the boilers. Unit 2 boiler has some slagging problems with Chem Mod use. To minimize slag accumulation, DTE requested AQD (approved) to allow MgOH to be injected in the boiler. Problems with slag accumulation continue even with the addition of MgOH.

I reviewed and obtained a copy of rolling 12-month usage (ending in August 2015) of refined coal, S-Sorb and Mer Sorb. Usage is below 12-month rolling limits. I randomly reviewed and obtained a daily record for September 15, 2015. Attached is also an Environmental Inspection Checklist conducted on August 26, 2015.

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.

PM stack tests conducted in August 3-6, 2010 and June 15-19, 2013 also included a PM-10, PM-2.5 (or condensable) test. The additional PM-10 and PM-2.5 tests are required by PTI No. 164-08B and should be done every 3 years for 10 years.

PTI No. 164-08B requires DTE to submit Annual Emission Analysis Report that compares 2010 actual emissions to baseline actual and projected actual emissions. The annual reports were submitted on March 20, 2015 and March 3, 2014. 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 calculations.

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.

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 is personnel working inside the cascades or transfer houses. Attached is a random log for August 23, 2015 and June 7, 2015.

There is a PM limit for the fly ash silo load out. VE readings are a surrogate 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 loaded from both silos either wet or dry. 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.

Belle River is required to conduct VE readings at the load-out point from each silo weekly. Readings are conducted to verify fugitive emissions coming out of the load out structure. They do not read from the load out point, which is located inside the 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 is a random Visible Emissions Log for August 2015. 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.

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 are subject to emission limits, tune up requirements, one-time energy assessment, and compliance certification reporting. DTE obtained a permit (PTI No. 132-14 issued November 26, 2014) to switch from fuel oil to natural gas. As of the date of inspection, the fuel switch has not yet occurred. A fuel meter is installed for each. The tune-up for the boilers was scheduled for October 2015.

Visible emissions readings are only required if the auxiliary boilers operate continuously for 24 hrs or more. Attached is a log of Daily Aux Boiler Opacity Run time Log from September 2014 to March 2015 and Aux Boiler Run Hours Log.

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.

Belle River Power Plant has only 1 active degreaser, 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. Dave inspected the cold cleaner on September 3, 2015.

Belle River has one emergency diesel generator (fire pump engine) subject to the RICE MACT. A tune-up and inspection (air cleaner, belts, hoses) were conducted on September 15, 2015.

Section 4 Belle River Peakers

This section is for the five (5) diesel peaking units (2.5 MW each) and three (3) 82.4 MW peaking combustion turbine generators. These peakers are part of the Belle River Power Plant. CTGs' 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.

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. Attached is a log of year-to-date (September 8, 2015) run hours for all 5 engines. For RICE MACT compliance, these engines are considered limited use engines.

The combustion turbines are subject to the Acid Rain and the Clean Air Interstate Rule (CAIR). The ROP will be reopened to replace CAIR with CSAPR. NOTE: The Belle River combustion turbines are included in the Acid Rain Permit and CAIR (now CSAPR) Permit for the Belle River Power Plant.

To comply with the Acid Rain and CAIR 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.

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 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 are required to be maintained within a specified range. Part 75 appendix E requires a NOx emission rate test once every 20 calendar quarters.

Detroit Edison chose to monitor and maintain within a given range, the following 4 parameters: pitch, 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. Detroit Edison provided records indicating operating parameters were not exceeded for more than 16 hours. From September 1, 2014 until August 19, 2015, for CTG121 highest consecutive hours exceedance is 11 hrs. (July 27, 2015); for CTG122, 3 hrs. (January 14, 2015); and for CTG131, 4 hrs (August 6, 2015).

NOx mass emissions have to be determined to comply with the 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. NOx emissions calculations are done through the DAHS.

CO and PM-10 mass emissions are calculated using the worst case emission factors obtained from the most recent stack tests. CO testing is done in conjunction with NOx testing (once every 20 calendar quarters). PM-10 testing is conducted every 5 years (ROP requirement). The results of the NOx testing are incorporated in the PEMS. NOx mass emissions are calculated using the DAHS (data acquisition and handling system). The CTGs were tested in 2007 and 2012.

Compliance with the NOx and CO ppm limit has been demonstrated during the stack test conducted in 2012.

The ROP summary report of emission values (for the 12-month period ending in July 2015) for the CTGs is attached to this activity report. The summary report includes the following information: total amount of the natural gas used; NOx, CO, and PM emissions; startup and shutdown hours for each turbine; and capacity factor for each turbine. Certified VE readings for the three turbines were conducted June 30, 2014. Information submitted shows compliance with the limits.

A quarterly visual inspection of the CTG silencer is required. Silencers were repacked with new insulation in June/July of 2010.

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 DTEES Peakers

This section is for four (4) 82.4 MW peaking combustion turbine generators operated by DTE Energy Services, a subsidiary of the Detroit Edison Company. CTGs' rating is dependent on ambient temperature. In the winter, the CTGs can generate more than its' rated capacity - in the summer, less. The turbines were installed in 2001 and are subject to NSPS Subpart GG.

These turbines are identical to the turbines in Section 4 and are subject to the same regulations. The combustion turbines are subject to the Acid Rain and the Clean Air Interstate

Rule (CAIR). The combustion turbines are subject to the Acid Rain and the Clean Air Interstate Rule (CAIR). The ROP will be reopened to replace CAIR with CSAPR.

To comply with the Acid Rain and CAIR, 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.

NOx mass emissions have to be determined to comply with the emissions trading program. NOx emissions are calculated hourly, based on turbine load. Note that NOx emissions-turbine load correlation is not constant, but varies depending on a given turbine load. NOx emissions calculations are done through the DAHS.

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 testing is done every 5 years. The results of the NOx testing are incorporated in the PEMS. NOx mass emissions are calculated using the DAHS (data acquisition and handling system). The CTGs were tested 2007 and 2012. Compliance with the PM-10, NOx and CO ppm limit was demonstrated during the stack test.

If pipeline quality natural gas is used, NSPS no longer requires a custom fuel monitoring plan to verify sulfur content. Monitoring of nitrogen in fuel is not required if an allowance for fuel bound nitrogen is not claimed by the facility.

The summary of emission values for ROP for the CTGs for the 12-month period ending in August 2015 is attached. The attached report 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 for each turbine; peak and base load operating hours for all turbines, and capacity factor for each turbine. Records submitted show compliance. See attached usage and emissions records.

Whenever one or more of the four turbine QA/QC operating parameter is continuously exceeded for one or more successive operating periods totaling 16 unit operating hours, NOx emission rate is required to be retested. Detroit Edison chose to monitor and maintain within a given range, the following 4 parameters: pitch, compressor discharge temperature, compressor discharge pressure and exhaust temperature. The combustion peakers were operated for a limited number of hours in 2015. Exceeding any of the four operating parameters for more than 16 successive operating hours is not expected. See attached records indicating any of the four operating parameters were not exceeded for more than 16 hours from January 1 to December 31, 2014.

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.

NAME ________ DATE 12-22-15 SUPERVISOR CJE