STATE OF MICHIGAN
Rick Snyder, Governor

DEPARTMENT OF ENVIRONMENTAL QUALITY

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PUBLIC PARTICIPATION DOCUMENTS

For
Indeck Niles, LLC
Niles, Michigan

PERMIT APPLICATION NUMBER

75-16

November 7, 2016

FACT SHEET

November 7, 2016

Purpose and Summary

Indeck Niles, LLC (Indeck) is proposing to install and operate a new natural gas-fired combined-cycle (NGCC) power plant in Niles, Cass County, Michigan. This project is addressed in Permit to Install (PTI) Application No. 75-16.

The proposed project is subject to the permitting requirements of the Michigan Department of Environmental Quality's (MDEQ) Rules for Air Pollution Control and the state and federal Prevention of Significant Deterioration (PSD) regulations. The Air Quality Division (AQD) has evaluated this proposal and made a preliminary determination that the project will not violate any of the MDEQ's rules nor the health protective National Ambient Air Quality Standards (NAAQS) and the PSD air quality increments, which are intended to allow industrial growth in an area while ensuring that the area will continue to meet the NAAQS.

Prior to acting on this application, the AQD is holding a public comment period and a public hearing, if requested in writing, to allow all interested parties the opportunity to comment on the proposed PTI. All relevant information received during the comment period and hearing, if held, will be considered by the decision maker prior to taking final action on the application.

Background Information

In the proposed power generation process, inlet air will enter the combustion turbine where it will be compressed, mixed with natural gas, and ignited. This will cause the air to expand, creating pressure that will then turn the turbine blades. The spinning blades will be attached to a shaft, which will turn a generator and create electricity. The hot exhaust from each turbine (in excess of 800 degrees F) will be discharged into a heat recovery steam generator (HRSG) where the heat will be used to generate steam. The steam will be used to drive a steam turbine for additional electric generation. Air cooled condensers will be used to cool the steam exhausting from the steam turbine generator. Evaporative cooling will be used to reduce the temperature of the inlet air. Evaporative cooling is typically used in the summer months when ambient temperatures are high and the resulting turbine efficiency and power output is lower than International Organization of Standardization (ISO) conditions. Cooling the inlet air increases the density of the inlet air to the turbine resulting in a higher combustion air mass flow and increases power output. Evaporative cooling will be used so that the turbine efficiency and power output are less affected by ambient conditions.

Proposed Facility

The proposed new NGCC power plant would be used for electric generation. Its location at 2200 Progressive Drive in Niles, Michigan is currently a vacant railroad yard. The plant will feature state of the art turbine models with the latest technologies ("H" and "J" classes), which utilize higher firing temperatures (up to 1,620 degrees F) to achieve optimal efficiency of the units. Each combustion turbine generator (CTG) is connected to a HRSG, creating a single emission unit, which is referred to as a CTG/HRSG train. To reduce emissions of nitrogen oxides (NO_x), the high efficiency CTG/HRSG trains will be equipped with dry low-NO_x burners and selective catalytic reduction (SCR), and to reduce the emissions of carbon monoxide (CO) and volatile organic compounds (VOCs), they will be equipped with oxidation catalysts. This project covers all of the equipment at the proposed facility.

The plant will consist of the following equipment:

- Two natural gas-fired CTGs rated at 3,421 million British thermal units (MMBTU)/hr each;
- Two HRSGs, each equipped with a 740 MMBTU/hr duct burner;
- One natural gas-fired auxiliary boiler rated at 182 MMBTU/hr with a steam capacity of 150,000 lb/hr;
- Two natural gas-fired fuel dew point heaters rated at 27 MMBTU/hr each;
- One 2,922 horsepower (HP) diesel fired emergency reciprocating internal combustion engine with a heat input of approximately 23 MMBTU/hr;
- One 260 brake HP emergency diesel fire pump engine with a heat input capacity of 1.66 MMBTU/hr;
- Three water/condensate storage tanks with a closed roof design;
- Two diesel fuel tanks with a closed roof design;
- One aqueous ammonia storage tank with a closed roof design;
- Up to 44 space heaters rated at a combined 10 MMBTU/hr or less; and
- One closed-cover parts washer (cold cleaner).

Present Air Quality

The United States Environmental Protection Agency (USEPA) has set maximum permissible levels, referred to as National Ambient Air Quality Standards (or NAAQS), for seven criteria pollutants. The NAAQS are designed to protect the public health of everyone, including the most susceptible individuals: children, the elderly, and those with chronic respiratory ailments. The seven pollutants are CO, lead, nitrogen dioxide (NO_2), ozone, particulate matter equal to or less than 10 microns in diameter (PM10), particulate matter equal to or less than 2.5 microns in diameter (PM2.5), and sulfur dioxide (SO_2). The proposed facility location is in an attainment area for all criteria pollutants.

It should be noted that on October 26, 2015, the USEPA revised the 8-hour ozone NAAQS from 0.075 parts per million (ppm) to 0.070 ppm. The MDEQ anticipates that Cass County will remain in attainment following the October 2017 USEPA designations.

Pollutant Emissions

The PSD regulations and permitting requirements are triggered if the emission of one or more regulated new source review pollutant is greater than 100 tons per year (tpy) at a fossil fuel-fired steam electric plant of more than 250 MMBTU/hr heat input. For this application, a single CTG alone has a rating of 3,421 MMBTU/hr, and, as seen in Table 1 below, multiple pollutants exceed 100 tpy. Once PSD permitting requirements are triggered, any regulated new source review pollutant with emissions greater than its PSD significant emission rate, must also undergo PSD review. The PSD regulations are contained in Part 18 of the Michigan Air Pollution Control Rules and 40 CFR 52.21 of the federal rules.

This application is subject to PSD review for NO_x, CO, particulate matter (PM), PM10, PM2.5, SO_2, VOCs, sulfuric acid mist (H_2SO_4), and greenhouse gases (GHGs). GHGs are typically expressed in terms of carbon dioxide equivalents (CO_2e).

The following table provides the estimated emissions for each regulated new source review pollutant from the proposed project and their respective significant emission rates:

Table 1: Project Potential Emissions Summary

Pollutant	Estimated Emissions (tpy)	PSD Significant Emission Rate (tpy)	Subject to PSD?
NO_x	494*	40	Yes
CO	2,009*	100	Yes
PM	91.2	25	Yes
PM10	181	15	Yes
PM2.5	181	10	Yes
SO_2	103	40	Yes
Lead	3.63E-3	0.6	No
VOCs	948*	40	Yes
H_2SO_4	40.2	7	Yes
GHGs as CO_2e**	4,302,486	75,000	Yes

* These emissions include 500 hours of startup and shutdown operation for the CTG/HRSG trains.

** A recent decision by the Supreme Court (*Utility Air Regulatory Group v. U.S. EPA), No. 12-1146 (June 23, 2014*) determined that PSD review for GHGs is only required if one or more of the other regulated new source review pollutants exceeds a PSD threshold.

<u>Key Permit Review Issues</u>

The AQD staff evaluated the proposed project to identify all state rules and federal regulations which are, or may be, applicable. The tables in Appendix 1 summarize these rules and regulations.

- **Prevention of Significant Deterioration (PSD) Regulations**

  Based on the potential emissions, the new plant is subject to PSD review for NOx, CO, PM, PM10, PM2.5, SO_2, VOCs, H_2SO_4, and GHGs. Review under the PSD regulations requires Best Available Control Technology (BACT), a source impact analysis, an air quality impact analysis, and an additional impact analysis for each regulated new source review pollutant for which the project will result in significant emissions. The PSD major source threshold is 250 tpy for each of the regulated new source review pollutants for most sources. However, this plant is one of 28 source categories listed in the PSD regulations, so the PSD major source threshold is 100 tpy. Once a source is major for a single regulated new source review pollutant, it is major for other regulated new source review pollutants at their significant level. The emissions associated with the proposed project are summarized in Table 1 above.

  The BACT review determined both specific emission limits and add-on air pollution control equipment requirements. A summary of the BACT analysis and the specific BACT emission limits and add-on air pollution control equipment requirements is addressed in Appendix 2.

- **Minor/Major Modification Determination for Attainment Pollutants**

  The facility is a new PSD major stationary source as discussed above. The plant will be located in Cass County which is currently in attainment for all criteria pollutants. The proposed project is subject to PSD because the emissions of NOx, CO, PM10, PM2.5, VOCs, SO_2, and GHGs are all greater than 100tpy. The emissions of PM and H_2SO_4 are above their significant levels and are also subject to PSD review. Please refer back to Table 1 for a summary of the proposed emissions of each regulated new source review pollutant.

- **Federal NSPS Regulations**

  New Source Performance Standards (NSPS) were established under Title 40 of the Code of Federal Regulations (40 CFR) Part 60. Several pieces of equipment at the proposed Indeck plant will be subject to the various NSPS standards:

  The CTG/HRSG trains are subject to the NSPS Subpart KKKK for Stationary Combustion Turbines and Subpart TTTT for Greenhouse Gas Emissions for Electric Generating Units. Subpart KKKK contains a NO_x emission limit, a sulfur fuel content restriction, and associated compliance requirements. Subpart TTTT contains a carbon dioxide (CO_2) emission standard and an associated calculation method.

  The auxiliary boiler is subject to the NSPS Subpart Db for Industrial-Commercial-Institutional Steam Generating Units. Subpart Db contains a NO_x emission limit and associated compliance requirements.

  The fuel dew point heaters are subject to the NSPS Subpart Dc for Small Industrial-Commercial-Institutional Steam Generating Units. Subpart Dc requires fuel usage monitoring.

The diesel-fueled emergency engine and fire pump engine are both subject to the NSPS Subpart IIII for Stationary Compression Ignition Internal Combustion Engines. Subpart IIII contains non-methane hydrocarbon + NO_x, CO, and PM emission limits and associated compliance requirements.

- **Federal NESHAP Regulations**
  National Emission Standards for Hazardous Air Pollutants (NESHAP) were established under 40 CFR Part 63. A major source under the NESHAP is defined as having potential emissions of 10 tpy for a single hazardous air pollutant (HAP) or 25 tpy for all HAPs combined. An area source has potential HAP emissions below the major source values. The potential HAP emissions from the proposed facility will be below the major source values for both the single HAP and total HAPs thresholds. Therefore the plant will be an area source of HAP emissions. Several pieces of equipment at the Indeck plant will be subject to NESHAP standards:

  The diesel-fueled emergency engine and fire pump engine are both subject to 40 CFR Part 63 Subpart ZZZZ for Stationary Reciprocating Internal Combustion Engines. Subpart ZZZZ applies to both major and area sources. The only requirement for the engines is to comply with NSPS Subpart IIII.

- **Rule 224 TBACT Analysis**
  The MDEQ Rules for Air Pollution Control require that new or modified equipment that emits toxic air contaminants (TACs) must utilize the Best Available Control Technology for TACs (T-BACT), unless the equipment emits TACs that are particulates or VOC and are in compliance with BACT. Per Rule 224(2), the engines and the boilers are excluded from the T-BACT analysis because standards have been promulgated for them under the Part 63 NESHAPs, Subparts ZZZZ and JJJJJJ, respectively. Each other piece of proposed equipment underwent a top-down BACT analysis for VOC and PM, and the only TACs that were not covered through the PSD BACT review were ammonia and H_2SO_4.

  Ammonia is released during potential ammonia slip from the SCR process utilized for NO_x control on the CTG/HRSG trains. Indeck stated that T-BACT for reduction of ammonia slip is an efficiently designed and managed SCR system, and the AQD concurred with this determination.

  H_2SO_4 is formed as a result of the reaction of sulfur trioxide (SO_3) with water, either in the flue gas stream or in the atmosphere after discharge. SO_3 is formed as a result of the thermal oxidation of sulfur compounds in the fuel. Control technologies for sulfur compounds will also control H_2SO_4. A PSD BACT analysis for SO_2 and H_2SO_4 was performed and Indeck determined that additional control was not cost effective. The AQD concurred with this determination.

- **Rule 225 Toxics Analysis**
  The MDEQ Rules for Air Pollution Control require the ambient air concentration of TACs be compared against health-based screening levels. The AQD staff reviewed Indeck's air quality modeling and evaluation of TAC impacts. The review found that all TACs show impacts less than the established health-based screening levels and will comply with the requirements of Rule 225. The TACs whose impacts were greater than 10 percent of at least one of their screening levels are listed below in Table 2.

Table 2: TAC Impacts and Screening Levels

TAC / HAP	Averaging Period ($\mu g/m^3$)	Screening Level ($\mu g/m^3$)	Screening Level Type	PAI ($\mu g/m^3$)	Percent of Screening Level
Acrolein	1-hr	5	ITSL	5.3E-01	10.61%
	Annual	0.16	ITSL	2.3E-04	0.15%
Arsenic	Annual	0.0002	IRSL	3.5E-05	17.29%
Cadmium	Annual	0.0006	IRSL	1.9E-04	31.70%
Chromium*	Annual	0.008	ITSL	4.4E-05	0.54%
	Annual	0.000083	IRSL	4.4E-05	52.50%
Formaldehyde	24-hr	30	ITSL	3.1E-01	1.05%
	Annual	0.08	IRSL	2.3E-02	28.78%
Ammonia	1-hr	1200	ITSL	26	10.14%
	24-hr	100	ITSL	10	10.14%
PAHs**	Annual	0.0006	IRSL	1.8E-04	30%

* Chromium was evaluated at 18% hexavalent chromium, which is the USEPA's estimation for emissions from coal oil-fired boilers. In reality, the hexavalent chromium emissions will be a small fraction of the total chromium emissions from natural gas combustion. The emissions were evaluated in this way because of a lack of data regarding the exact amount. This is considered one of the most conservative methods of evaluation for chromium emissions from natural gas combustion.
** PAHs are polycyclic aromatic hydrocarbons, and multiple TACs are combined for the evaluation: benzo(a)anthracene, benzo(a)pyrene, benzo(b)fluoranthene, benzo(k)fluoranthene, 3-methylcholanthrene, 7,12-dimethylbenz(a)anthracene, chrysene, dibenz(a,h)anthracene, and indeno(1,2,3-cd)pyrene.

- **Rule 702 VOC Emissions**
  This rule requires an evaluation of the following four items to determine what will result in the lowest maximum allowable emission rate of VOCs:
  a. BACT or a limit listed by the department on its own initiative.
  b. New Source Performance Standards (NSPS).
  c. VOC emission rate specified in another permit.
  d. VOC emission rate specified in the Part 6 rules for existing sources.

  The VOC emissions are also subject to PSD review for this project. A top down BACT analysis was performed under the PSD regulations for all VOC sources. Specific VOC emission limits and control equipment requirements were determined to represent BACT under this review. The PSD BACT determinations satisfy the BACT requirements per Rule 702(a).

- **Criteria Pollutants Modeling Analysis**
  An air quality impact analysis, as required by Rules 336.2811 through 336.2813, was performed for NO_x, CO, PM10, PM2.5, and SO_2 emissions using computer dispersion modeling to predict the ambient air impacts. NO_x refers specifically to nitrogen oxide and NO_2 with the larger portion being that of NO_2, a highly reactive gas, which is what the USEPA established air quality standards for under the federal Clean Air Act.

  The goal of an air quality impact analysis is to evaluate if the proposed facility will meet the NAAQS and the PSD increments. The NAAQS are intended to protect public health. The PSD increments are intended to allow industrial growth in an area, while ensuring that the area will continue to meet the NAAQS.

The first step is to determine the predicted impacts from the proposed project. After the impacts are determined, they are compared to the applicable PSD Significant Impact Levels (SILs). If the project impacts are less than the SIL, then no further review is required.

To determine the predicted impacts, the dispersion modeling utilized two operating scenarios for the project and the worst case impact for each criteria pollutant, for each averaging time, was used in comparison to the maximum levels allowed. The two operating scenarios were for baseload operation and startup operation. The emergency engine has an operational restriction of 500 hours per year, and the fire pump engine has an operational restriction of 100 hours per year. The engines also have daily hours restrictions of 4 hours per day and 1 hour per day, except during emergency conditions, for the emergency engine and the fire pump engine, respectively. They were modeled as intermittent sources during the baseload operation and were not included in the startup modeling. The CTG/HRSG trains also utilized annualized emission rates for the startup modeling. In the proposed draft permit, a condition restricting the total number of startup and shutdown hours is included.

The SIL analysis considers the potential emissions from the proposed project for NO_2, CO, PM10, PM2.5, and SO_2 and compares them to the SIL, as shown in Table 3, below. There is no SIL for PM, VOC, H_2SO_4, or GHGs, and also no NAAQS or PSD Increment; therefore a modeling analysis is not required for those pollutants.

Table 3: Significant Impact Levels (SIL)

Pollutant	Averaging Period	SIL (ug/m^3)	Total Maximum Impact	Below SIL?
NO_2	1-Hour	7.5	121.1	No
	Annual	1	7.2	No
CO	1-Hour	2,000	6,764.6	No
	8-Hour	500	1,742.3	No
PM10	24-Hour	5	10.1	No
	Annual	1	1.2	No
PM2.5	24-Hour	1.2	9.4	No
	Annual	0.3	1.2	No
SO_2	1-Hour	7.8	22.6	No
	3-Hour	25	504.7	No
	24-Hour	5	8.5	No
	Annual	1	0.2	Yes

Since the results determined that the modeled ambient air impact for SO_2 on an annual average was less than its respective SIL, no further modeling was required for it. For each pollutant and averaging period where the results determined the modeled impacts exceeded the SIL, a facility-wide NAAQS and PSD Increment modeling analysis was required.

In the NAAQS analysis, the total facility impact includes additional nearby facilities, or offsite sources. The total facility impact and the background concentrations, which is data from ambient air monitors, are summed and compared to the NAAQS. There are no NAAQS for annual PM10 and 24-hour SO_2. The results of the NAAQS analysis are below in Table 4.

Table 4: NAAQS Analysis

Pollutant	Averaging Period	NAAQS (ug/m^3)	Facility + Offisite Sources Maximum Concentration (ug/m^3)	Secondary (ug/m^3)	Background Concentration (ug/m^3)	Total Concentration** (ug/m^3)	Below NAAQS?
NO_2	1-Hour	188	84.9	--	76.4	161.3	Yes
	Annual	100	7.2	--	15.7	22.9	Yes
CO	1-Hour	40,000	6,764.6	--	2,320.0	9,084.6	Yes
	8-Hour	10,000	1,742.3	--	1,508.0	3,250.3	Yes
PM10	24-Hour	150	10.1	--	29.0	39.1	Yes
PM2.5*	24-Hour	35	5.8	1.31	22.6	29.7	Yes
	Annual	12	1.1	0.05	9.6	10.8	Yes
SO_2	1-Hour	196	15.4	--	27.1	42.5	Yes
	3-Hour	1,300	504.7	--	24.6	529.3	Yes

* Includes secondary PM2.5 formation from precursors of NO_x and SO_2.
** This is the total impact from the facility plus background.

The PSD increments are compared against the total facility impact plus other increment consuming facilities nearby. There are no PSD Increments for 1-hour NO_2, CO, and 1-hour SO_2. The results of the PSD increment analysis are below in Table 5.

Table 5: PSD Increment Analysis

Pollutant	Averaging Period	PSD Increment (ug/m^3)	Facility + Offisite Sources Maximum Concentration (ug/m^3)	Secondary (ug/m^3)	Total (ug/m^3)	Below PSD Increment?
NO_2	Annual	25	7.2	--	7.2	Yes
PM10	24-Hour	30	7.4	--	7.4	Yes
	Annual	17	1.4	--	1.4	Yes
PM2.5*	24-Hour	9	7.4	1.31	8.7	Yes
	Annual	4	1.4	0.05	1.45	Yes
SO_2	3-Hour	512	277.8	--	277.8	Yes
	24-Hour	91	5.8	--	5.8	Yes

* Includes secondary PM2.5 formation from precursors of NO_x and SO_2.

There is an 8-hour NAAQS for ozone, but no PSD increment. Ground-level ozone concentrations are the result of photochemical reactions among various chemical species. The chemical species that contribute to ozone formation, referred to as ozone precursors, include NO_x and VOC emissions from both anthropogenic (e.g., mobile and stationary sources) and natural sources (e.g., vegetation). The facility will emit both NO_x and VOC at levels greater than 100 tpy, thus triggering the ozone ambient impact analysis requirements of R 336.2809 and 40 CFR 51.166.

The secondary formation of ozone, or conversion of the precursors, is not instantaneous; it happens over time and is highly dependent upon weather conditions. Therefore, the conversion is often completed after the precursors have been dispersed away from the immediate area. Because of this, ozone formation is recognized as a long-range transport issue. As a result, there are no effective modeling methods for ozone for single sources: the ozone modeling programs address larger areas of land and air movements and therefore must include many sources.

To address whether or not a project may cause or contribute to a violation of the ozone NAAQS, the ozone precursors, NO_x and VOC, are evaluated. Indeck used data from the recently promulgated Cross-State Air Pollution Rule to estimate ozone precursor contributions. It is not expected that the precursor emissions will have a significant impact on the ozone levels in this area. When the contributions are added to the background concentration, the total impact is below the new proposed ozone NAAQS of 0.070 ppm.

Preconstruction monitoring is required for at least one year for each criteria pollutant proposed to be emitted that triggers PSD review. Through guidance, the USEPA allows the use of existing regional data, if representative, as an alternative to the preconstruction monitoring. Indeck requested to use existing data and to receive a waiver from preconstruction monitoring. The AQD determined that the data is representative and granted the waiver request.

- **Additional Impact Analysis**

  An additional impact analysis is required for new major sources pursuant to 40 CFR 52.21(o) and Rule 336.2815. This analysis is necessary to evaluate the impacts from the proposed project on soils, vegetation, visibility and growth.

  The proposed project emissions are not anticipated to have a negative impact on soils, vegetation, wildlife, or visibility, and to have minimal impact on growth once construction is completed.

  Soils, Vegetation, and Wildlife

  The secondary NAAQS have been determined by the USEPA to be protective of soils, vegetation, and wildfire. Indeck evaluated the secondary NAAQS using dispersion modeling. All PSD pollutants with secondary NAAQS were below their respective standards. VOCs and H_2SO_4 were evaluated through the TAC analysis required in Michigan Air Pollution Control Rule 336.1225. This evaluation showed that the impacts from the project are below their respective health-based screening levels.

Visibility
Assessments for visibility impacts are required only for Class I areas. The nearest Class I area is in Seney, Michigan, which is located approximately 494 kilometers away from Indeck. The source is sufficiently far away that USEPA does not require further analysis as no impairment to visibility in the Class I area is expected to occur.

Growth
The growth analysis is a projection of the commercial, residential, industrial, and other growth that will occur in the area due to the construction and operation of the proposed source. Emissions from construction are expected to be minimal and have limited impact beyond the site boundaries. Employment due to construction will be temporary, and the number of permanent jobs will be small. It is predicted to have a minimal effect on area population and commercial growth.

Key Aspects of Draft Permit Conditions

- **Emission Limits (By Pollutant)**
  The draft permit includes emission limits for various pollutants in order to make the permit enforceable and to protect the air quality standards. Included are PSD BACT emission limits, as appropriate, for NO_x, CO, PM, PM10, PM2.5, SO_2, VOC, H_2SO_4, and GHGs as CO_2e. A summary of the BACT emission limits is included in Appendix 2.

  The draft permit also includes NSPS emission limits as described below:

  Stand-alone
  - NSPS Subpart KKKK for the CTG/HRSG trains allows for NO_x emissions of 15 ppm at 15% O_2 on a 30-day rolling average basis.

  Subsumed:
  - NSPS Subpart TTTT for the CTG/HRSG trains allows for CO_2 emissions of 1,000 lb/MWh. The PSD BACT emission limit is more stringent, and the NSPS limit is considered subsumed.
  - NSPS Subpart Db for the auxiliary boiler allows for NO_x emissions of 0.20 lb/MMBTU at a high heat release rate. The PSD BACT emission limit is more stringent, and the NSPS limit is considered subsumed.

- **Emission Control Device Requirements**
  The draft permit includes the following emission control device requirements:

  - Each CTG/HRSG train: Dry low NO_x burners (DLNB) and SCR for NO_x control. An oxidation catalyst for CO and VOC control.
  - Auxiliary boiler: Low NOx burners (LNB) and flue gas recirculation (FGR) for NO_x control.
  - Diesel Fuel Tanks: Conservation vent valves for VOC control.

- **Usage Limits**
  The draft permit only allows the combustion of pipeline quality natural gas in the CTGs, HRSG duct burners, auxiliary boiler, fuel heaters, and natural gas-fired space heaters. The draft permit also limits the fuel to only ultra-low sulfur diesel fuel with the maximum sulfur content of 15 ppm (0.0015 percent) by weight for the emergency engine and the fire pump engine.

- **Process/Operational Restrictions**
  The draft permit requires Indeck to develop a Malfunction Abatement Plan (MAP) for the CTG/HRSG trains and the auxiliary boiler. The plan must include a preventative maintenance program and corrective procedures in the event of an equipment malfunction or failure.

  Also, the draft permit requires Indeck to develop an additional plan that describes how emissions will be minimized during startup and shutdown for the CTG/HRSG trains and the auxiliary boiler. The plan shall incorporate procedures recommended by the equipment manufacturer as well as incorporate standard industry practices. The draft permit includes a restriction of 500 combined hours of startup and shutdown per year for each CTG/HRSG train.

  The draft permit includes hours restrictions of 500 hours per year for the emergency engine and 100 hours per year for the fire pump engine. Also, the emergency engine is limited to 4 hours per day except during emergency conditions and required stack testing, and the fire pump engine is limited to 1 hour per day except during emergency conditions and required stack testing.

- **Testing & Monitoring Requirements**
  The draft permit includes emissions testing, monitoring, and recordkeeping requirements for all emission units.

  CTG/HRSG Trains
  - The maximum design heat input capacity, on a fuel heat input basis, for each CTG shall not exceed 3,421 MMBTU/hr and for each duct burner shall not exceed 740 MMBTU/hr.
  - Continuous Emission Monitoring System (CEMS) devices to monitor and record NO_x and CO emissions from each CTG/HRSG train are required. As part of CEMS, a monitor for either oxygen or CO_2 is also required.
  - Testing for PM, PM10, PM2.5, SO_2, VOC, and H_2SO_4 emission rates are required.
  - Emissions records for NO_x, CO, CO_2, and CO_2e for each CTG/HRSG train are required.
  - Records of the fuel usage on a monthly basis.
  - Records of the hours for startup and shutdown events for each CTG/HRSG train are required.

Auxiliary Boiler

- The maximum design heat input capacity shall not exceed 182 MMBTU/hr on a fuel heat input basis.
- CEMS devices to monitor and record NO_x emissions, along with either oxygen or CO_2, are required.
- Testing is required for CO, PM, and VOC emissions and for PM10 and PM2.5 emission factors.
- Emissions records for NO_x, PM10, PM2.5, and CO_2e are required.
- Records of the hourly and daily fuel usage rate are required.
- Records validating the SO_2 emission factor are required.

Fuel Heaters

- The maximum design heat input capacity for each fuel heater shall not exceed 27 MMBTU/hr on a fuel heat input basis. When operating at the same time, the combined heat input shall not exceed 27 MMBTU/hr on a fuel heat input basis.
- Testing is required for PM emissions.
- A record of the hourly fuel usage rate is required.
- Records of NO_x, CO, PM10, PM2.5, VOC, and CO_2e mass emissions are required.

Emergency Engine

- The nameplate capacity shall not exceed 2,179 kilowatt (kW) (2,922 HP).
- Emissions testing or manufacturer certification documentation is required for non-methane hydrocarbon (NMHC) + NO_x, CO, and PM emission rates.
- Testing is required for VOC emission rates.
- A record of the fuel usage rate is required.
- Records of PM10, PM2.5, and CO_2e mass emissions are required.
- Monitor and record the total hours of operation and the hours of operation during non-emergencies.

Fire Pump Engine

- The nameplate capacity shall not exceed 260 brake HP.
- Emissions testing or manufacturer certification documentation is required for NMHC + NO_x, CO, and PM emission rates.
- Testing is required for VOC emission rates.
- A record of the fuel usage rate is required.
- Records of PM10, PM2.5, and CO_2e mass emissions are required.
- Monitor and record the total hours of operation and the hours of operation during non-emergencies.

- **Federal Regulations**
  Each of the two proposed CTG/HRSG trains will be subject to the NSPS for Stationary Combustion Turbines, 40 CFR Part 60 Subpart KKKK, and the NSPS for Greenhouse Gas Emissions for Electric Generating Units, 40 CFR Part 60 Subpart TTTT. Also, the auxiliary boiler will be subject to the NSPS for Industrial-Commercial-Institutional Steam Generating Units, 40 CFR Part 60 Subpart Db. The fuel dew point heaters will be subject to the NSPS for Small Industrial-Commercial-Institutional Steam Generating Units, 40 CFR Part 60 Subpart Dc. The emergency engine and the fire pump engine will be subject to the NSPS for Stationary Compression Ignition Internal Combustion Engines, 40 CFR Part 60 Subpart IIII. The draft permit specifies that compliance with certain permit conditions will constitute compliance with the respective NSPS for each emission unit through required emission limits, process/operational restrictions, testing or certification, monitoring/recordkeeping, and reporting.

  The proposed engines will also be subject to the NESHAP for Stationary Reciprocating Internal Combustion Engines, 40 CFR Part 63 Subpart ZZZZ. New engines at any area source of HAPs that are subject to Subpart IIII, must meet the requirements of NSPS Subpart IIII and have no additional requirements under the NESHAP.

Conclusion

Based on the analyses conducted to date, the AQD staff concludes that the proposed project would comply with all applicable state and federal air quality requirements. The AQD staff also concludes that this project, as proposed, would not violate the federal NAAQS or the federal PSD increments.

Based on these conclusions, the AQD staff has developed draft permit terms and conditions which would ensure that the proposed facility design and operation are enforceable and that sufficient monitoring, recordkeeping, and reporting would be performed by the applicant to determine compliance with these terms and conditions. If the permit application is deemed approvable, the delegated decision maker may determine a need for additional or revised conditions to address issues raised during the public participation process.

If you would like additional information about this proposal, please contact Ms. Catherine Asselin, AQD, at 517-284-6786.

Appendix 1

STATE AIR REGULATIONS

State Rule	Description of State Air Regulations
R 336.1201	Requires an Air Use Permit for new or modified equipment that emits, or could emit, an air pollutant or contaminant. However, there are other rules that allow smaller emission sources to be installed without a permit (see Rules 336.1279 through 336.1290 below). Rule 336.1201 also states that the Department can add conditions to a permit to assure the air laws are met.
R 336.1205	Outlines the permit conditions that are required by the federal Prevention of Significant Deterioration (PSD) Regulations and/or Section 112 of the Clean Air Act. Also, the same types of conditions are added to their permit when a plant is limiting their air emissions to legally avoid these federal requirements. (See the Federal Regulations table for more details on PSD.)
R 336.1224	New or modified equipment that emits toxic air contaminants must use the Best Available Control Technology for Toxics (T-BACT). The T-BACT review determines what control technology must be applied to the equipment. A T-BACT review considers energy needs, environmental and economic impacts, and other costs. T-BACT may include a change in the raw materials used, the design of the process, or add-on air pollution control equipment. This rule also includes a list of instances where other regulations apply and T-BACT is not required.
R 336.1225 to R 336.1232	The ambient air concentration of each toxic air contaminant emitted from the project must not exceed health-based screening levels. Initial Risk Screening Levels (IRSL) apply to cancer-causing effects of air contaminants and Initial Threshold Screening Levels (ITSL) apply to non-cancer effects of air contaminants. These screening levels, designed to protect public health and the environment, are developed by Air Quality Division toxicologists following methods in the rules and U.S. EPA risk assessment guidance.
R 336.1279 to R 336.1290	These rules list equipment to processes that have very low emissions and do not need to get an Air Use permit. However, these sources must meet all requirements identified in the specific rule and other rules that apply.
R 336.1301	Limits how air emissions are allowed to look at the end of a stack. The color and intensity of the color of the emissions is called opacity.
R 336.1331	The particulate emission limits for certain sources are listed. These limits apply to both new and existing equipment.
R 336.1370	Material collected by air pollution control equipment, such as dust, must be disposed of in a manner, which does not cause more air emissions.
R 336.1401 and R 336.1402	Limit the sulfur dioxide emissions from power plants and other fuel burning equipment.
R 336.1601 to R 336.1651	Volatile organic compounds (VOCs) are a group of chemicals found in such things as paint solvents, degreasing materials, and gasoline. VOCs contribute to the formation of smog. The rules set VOC limits or work practice standards for existing equipment. The limits are based upon Reasonably Available Control Technology (RACT). RACT is required for all equipment listed in Rules 336.1601 through 336.1651.
R 336.1702	New equipment that emits VOCs is required to install the Best Available Control Technology (BACT). The technology is reviewed on a case-by-case basis. The VOC limits and/or work practice standards set for a particular piece of new equipment cannot be less restrictive than the Reasonably Available Control Technology limits for existing equipment outlined in Rules 336.1601 through 336.1651.
R 336.1801	Nitrogen oxide emission limits for larger boilers and stationary internal combustion engines are listed.
R 336.1901	Prohibits the emission of an air contaminant in quantities that cause injurious effects to human health and welfare, or prevent the comfortable enjoyment of life and property. As an example, a violation may be cited if excessive amounts of odor emissions were found to be preventing residents from enjoying outdoor activities.
R 336.1910	Air pollution control equipment must be installed, maintained, and operated properly.

STATE AIR REGULATIONS

State Rule	Description of State Air Regulations
R 336.1911	When requested by the Department, a facility must develop and submit a malfunction abatement plan (MAP). This plan is to prevent, detect, and correct malfunctions and equipment failures.
R 336.1912	A facility is required to notify the Department if a condition arises which causes emissions that exceed the allowable emission rate in a rule and/or permit.
R 336.2001 to R 336.2060	Allow the Department to request that a facility test its emissions and to approve the protocol used for these tests.
R 336.2801 to R 336.2804 Prevention of Significant Deterioration (PSD) Regulations **Best Available Control Technology (BACT)**	The PSD rules allow the installation and operation of large, new sources and the modification of existing large sources in areas that are meeting the National Ambient Air Quality Standards (NAAQS). The regulations define what is considered a large or significant source, or modification. In order to assure that the area will continue to meet the NAAQS, the permit applicant must demonstrate that it is installing the BACT. By law, BACT must consider the economic, environmental, and energy impacts of each installation on a case-by-case basis. As a result, BACT can be different for similar facilities. In its permit application, the applicant identifies all air pollution control options available, the feasibility of these options, the effectiveness of each option, and why the option proposed represents BACT. As part of its evaluation, the Air Quality Division verifies the applicant's determination and reviews BACT determinations made for similar facilities in Michigan and throughout the nation.
R 336.2901 to R 336.2903 and R 336.2908	Applies to new "major stationary sources" and "major modifications" as defined in R 336.2901. These rules contain the permitting requirements for sources located in nonattainment areas that have the potential to emit large amounts of air pollutants. To help the area meet the NAAQS, the applicant must install equipment that achieves the Lowest Achievable Emission Rate (LAER). LAER is the lowest emission rate required by a federal rule, state rule, or by a previously issued construction permit. The applicant must also provide emission offsets, which means the applicant must remove more pollutants from the air than the proposed equipment will emit. This can be done by reducing emissions at other existing facilities. As part of its evaluation, the AQD verifies that no other similar equipment throughout the nation is required to meet a lower emission rate and verifies that proposed emission offsets are permanent and enforceable.

FEDERAL AIR REGULATIONS

Citation	Description of Federal Air Regulations or Requirements
Section 109 of the Clean Air Act – National Ambient Air Quality Standards (NAAQS)	The United States Environmental Protection Agency has set maximum permissible levels for seven pollutants. These NAAQS are designed to protect the public health of everyone, including the most susceptible individuals, children, the elderly, and those with chronic respiratory ailments. The seven pollutants, called the criteria pollutants, are carbon monoxide, lead, nitrogen dioxide, ozone, particulate matter less than 10 microns (PM10), particulate matter less than 2.5 microns (PM2.5), and sulfur dioxide. Portions of Michigan are currently non-attainment for either lead or sulfur dioxide. Further, in Michigan, State Rules 336.1225 to 336.1232 are used to ensure the public health is protected from other compounds.

FEDERAL AIR REGULATIONS

Citation	Description of Federal Air Regulations or Requirements
40 CFR 52.21 – Prevention of Significant Deterioration (PSD) Regulations **Best Available Control Technology (BACT)**	The PSD regulations allow the installation and operation of large, new sources and the modification of existing large sources in areas that are meeting the NAAQS. The regulations define what is considered a large or significant source, or modification. In order to assure that the area will continue to meet the NAAQS, the permit applicant must demonstrate that it is installing BACT. By law, BACT must consider the economic, environmental, and energy impacts of each installation on a case-by-case basis. As a result, BACT can be different for similar facilities. In its permit application, the applicant identifies all air pollution control options available, the feasibility of these options, the effectiveness of each option, and why the option proposed represents BACT. As part of its evaluation, the Air Quality Division verifies the applicant's determination and reviews BACT determinations made for similar facilities in Michigan and throughout the nation.
40 CFR 60 – New Source Performance Standards (NSPS)	The United States Environmental Protection Agency has set national standards for specific sources of pollutants. These New Source Performance Standards (NSPS) apply to new or modified equipment in a particular industrial category. These NSPS set emission limits or work practice standards for over 60 categories of sources.
40 CFR 63— National Emissions Standards for Hazardous Air Pollutants (NESHAP)	The United States Environmental Protection Agency has set national standards for specific sources of pollutants. The National Emissions Standards for Hazardous Air Pollutants (NESHAP) (a.k.a. Maximum Achievable Control Technology (MACT) standards) apply to new or modified equipment in a particular industrial category. These NESHAPs set emission limits or work practice standards for over 100 categories of sources.
Section 112 of the Clean Air Act **Maximum Achievable Control Technology (MACT)** **Section 112g**	In the Clean Air Act, Congress listed 189 compounds as Hazardous Air Pollutants (HAPS). For facilities which emit, or could emit, HAPS above a certain level, one of the following two requirements must be met: 1) The United States Environmental Protection Agency has established standards for specific types of sources. These Maximum Achievable Control Technology (MACT) standards are based upon the best-demonstrated control technology or practices found in similar sources. 2) For sources where a MACT standard has not been established, the level of control technology required is determined on a case-by-case basis.

Notes: An "Air Use Permit," sometimes called a "Permit to Install," provides permission to emit air contaminants up to certain specified levels. These levels are set by state and federal law, and are set to protect health and welfare. By staying within the levels set by the permit, a facility is operating lawfully, and public health and air quality are protected.

The Air Quality Division does not have the authority to regulate noise, local zoning, property values, off-site truck traffic, or lighting.

These tables list the most frequently applied state and federal regulations. Not all regulations listed may be applicable in each case. Please refer to the draft permit conditions provided to determine which regulations apply.

Appendix 2
Best Available Control Technology Analysis
(Michigan Rule 336.2810 and 40 CFR 52.21(j))

A requirement of PSD New Source Review is a Best Available Control Technology (BACT) analysis. The top-down BACT approach per the USEPA DRAFT New Source Review Workshop Manual (October 1990) was utilized. The top-down approach considers all available emission reduction options and proceeds in a five-step process as follows:

1. Identify all control technologies;
2. Eliminate technically infeasible options;
3. Rank the remaining control technologies by control effectiveness;
4. Evaluate the most effective controls and document the results;
5. Select BACT (e.g., the most effective option not rejected is BACT).

The proposed project is subject to a BACT analysis for NO_x, CO, VOCs, PM, PM10, PM2.5, SO_2, H_2SO_4, and GHGs (as CO_2e). The following is a summary of the BACT analysis for each of the different pieces of equipment proposed to be installed.

Two Combined-Cycle CTG/HRSG Trains: Natural Gas-fired CTG with a HRSG equipped with a duct burner for supplemental firing

The CTG design proposed is either an "H" or "J" class turbine. These classes typically have higher firing temperatures to achieve optimal efficiency of the units.

BACT for NO_x
NO_x is generated thermally when nitrogen reacts with oxygen in the combustion air in a high temperature environment, and from oxidation of organic nitrogen compounds in the fuel (fuel NO_x). Fuel properties have a significant impact on NO_x formation. Pipeline quality natural gas contains free nitrogen, but no fuel bound nitrogen. Indeck identified several combustion and post combustion control technologies for the control of NO_x emissions from each CTG/HRSG train. The following technologies were identified and evaluated:

Combustion and Post Combustion Controls	• DLNB • Water or steam injection • SCR • Non-Selective Catalytic Reduction (NSCR) • Selective Non-Catalytic Reduction (SNCR) • EM_x^{TM} (Formerly $SCONO_x^{TM}$) • Xonon Cool Combustion™

The review of each of these technologies is summarized below.

- DLNB are commonly combined with post combustion controls to achieve the lowest NO_x emission rates. DLNB control fuel and air mixing ratios in the burner of the turbine in order to reduce flame temperature and reduce thermal NO_x formation. This technology is considered a technically feasible control alternative and will be the baseline scenario since the proposed turbines will be designed with DLNB.

- Water or steam is injected into the combustion air of the turbine to increase the thermal mass of the combustion flame by dilution. Heat is dissipated and the thermal NO_x produced is reduced. Water or steam injection is not compatible with dry low-NO_x burners, which are considered for this project; therefore, this technology is not considered a technically feasible control alternative.

- SCR is a post combustion system that consists of an ammonia injection system and a catalytic reactor. Ammonia is injected into the flue gas where it reacts with NO_x in the presence of the catalyst to form molecular nitrogen (N_2) and water. This reaction occurs at flue gas temperatures of 400°F to 800°F. The efficiency of the SCR system operation depends on catalyst reactivity, routine replacement of the catalyst, and maintaining a proper ammonia injection rate. This technology is considered a technically feasible control alternative.

- NSCR is a post combustion system that utilizes a three-way catalytic converter to reduce emissions of NO_x, CO, and VOC from the flue gas. No chemical injection is necessary; unburned hydrocarbons are the NO_x reducing agent. The reactions occur at flue gas temperatures of 800°F to 1,200°F and minimal oxygen content. This technology can be used in conjunction with an oxidation catalyst for further CO and VOC control. The exhaust gases from the CTG/HRSG trains will be too high in oxygen content for this control technology to be effective. This technology is not considered a technically feasible control alternative.

- SNCR is a post combustion system that injects ammonia or urea into combustion flue gases to form molecular nitrogen (N_2) and water. This reaction occurs at flue gas temperatures of 1,600°F to 2,100°F as the technology does not utilize a catalyst to promote the reaction. The NO_x reduction reactions are driven by the thermal decomposition of urea or ammonia and the subsequent chemical reaction reduction of NO_x. The technology is less effective at lower levels of uncontrolled NO_x. The exhaust gases from the CTG/HRSG train typically range from 800°F to 1,100°F. This technology is not considered a technically feasible control alternative because there is not an appropriate temperature window for ammonia injection and adequate reduction of NO_x in the exhaust gases.

- EMx^{TM} is similar to SCR, except that NO_x in the exhaust stream reacts with potassium carbonate (K_2CO_3) to form potassium nitrate (KNO_3). This compound is reacted with hydrogen to form gaseous nitrogen (N_2), and regenerate the K_2CO_3. Due to the temperature sensitivity of the catalyst beds, the lower exhaust temperature required for the reactions in the EMx^{TM} to take place is less than that of SCR. The EMx^{TM} system also provides reductions in CO emissions and to a lesser degree, reductions in VOC emissions by oxidation. This technology has not been demonstrated in practice on a larger utility CTG. Therefore, EMx^{TM} is not considered a technically feasible control alternative for this project.

- Xonon Cool Combustion™ uses a catalyst instead of a flame in the combustion process, enabling combustion at temperatures below the threshold at which thermal NO_x forms. This technology has not been demonstrated in practice on a larger utility CTG. Therefore, Xonon Cool Combustion™ is not considered a technically feasible control alternative for this project.

Water or steam injection, NSCR, SNCR, EMx™, and Xonon Cool Combustion™ were considered not technically feasible for this application. The technically feasible control technologies were ranked by control effectiveness as follows:

Control System	Expected Effectiveness/Control Efficiency (%)
SCR with DLNB	80-90
DLNB	70-80

SCR was not ranked alone as DLNB is intrinsic to the combustion design of all the potential turbines that will be considered for purchase.

It is proposed that BACT for NO_x is the use of SCR technology and DLNB, together with emission limits at different operating scenarios. It is necessary to include a BACT limit during steady state (normal) operation as well as during startup and shutdown, where combustion is inefficient and emission rates per unit of fuel combusted are significantly elevated compared to normal operation. At low loads, the combustors are not yet operating in lean pre-mix mode which contributes to higher NOx emission rates.

During normal operation, BACT is represented by an emission limit of 3 ppmv dry at 15 percent oxygen based on a 24-hour rolling average and 38.06 pounds per hour based on a 24-hour rolling average for each CTG/HRSG train.

During SU/SD operations, each CTG/HRSG train is limited to a total of 500 hours per 12-month rolling time period. BACT is represented by an emission limit of 286 pounds per hour during startup and shutdown, which is based on an operating hour.

All mass emission limits are protective of NAAQS and PSD increment.

Compliance with these limits will be monitored using a NO_x CEMS. The CEMS will comply with Part 60 and Part 75 regulations.

BACT for CO and VOCs
CO and VOC emissions result from the incomplete combustion of carbon-bearing fuels, such as natural gas. The primary influencing factors for CO and VOC formation are the combustion temperature, turbulence (mixing of fuel and oxygen), and the residence time in the combustion zone. Indeck identified combustion and post combustion control technologies for the control of CO and VOC emissions from each CTG/HRSG train. The following technologies were identified for both CO and VOC and were evaluated:

Combustion and Post Combustion Controls	• Oxidation Catalyst • Thermal Oxidation • NSCR • Good Combustion Practices (Efficient Combustion)

NSCR was described above in the NOx BACT discussion. The review of the rest of these technologies is summarized below.

- Oxidation Catalysts have been applied to combustion turbines and have demonstrated their ability to effectively reduce CO and VOC emissions. They are also commercially available from numerous vendors. A catalyst bed is utilized to oxidize CO and hydrocarbons to CO_2. This reaction can occur over a temperature range of 450°F to 1,200°F. The operating temperature, gas composition, and pressure drop across the catalyst bed are all factors that will affect the efficiency of the oxidation catalyst. Typical reduction of CO emissions is 85-90 percent. This technology is considered a feasible control alternative for this project.
- Thermal oxidation increases the temperature of the flue gas above the auto-ignition temperature of CO and other hydrocarbons, which is 1,300°F, to induce combustion of flue gas contaminants (CO and VOC). This technology is typically designed for process streams that have high concentrations of VOC. This allows the contaminants to provide a significant portion of the fuel requirements. Relative to the entire exhaust flow, the CTG/HRSG trains will have relatively low concentrations of CO and VOCs. This technology is not considered a technically feasible control alternative for this project.
- Good combustion practices, or efficient combustion, revolves around operating the equipment properly and must be balanced with the potential increase of NOx emissions that could occur when combustion efficiency is associated with high chamber temperatures. Modern combustion controls are able to reasonably balance this counter-acting relationship.

Thermal oxidation and NSCR were considered not technically feasible for this application. The technically feasible control technologies were proposed as BACT and were therefore not ranked.

It is proposed that BACT for CO and VOC emissions is oxidation catalyst technology and the use of good combustion control practices together with emission limits. It is necessary to include a BACT limit during steady state (normal) operation and an alternative BACT limit during startup and shutdown, where combustion is inefficient and emission rates per unit of fuel combusted are elevated compared to normal operation. At the very early stages of the startup cycle, the oxidation catalyst is technology limited and it is difficult to accurately measure CO because of specific stack O_2 conditions. During SU/SD events, the add-on oxidation catalyst control technology is not fully functional due to the exhaust gas temperature through the HRSG being less than the temperature necessary for optimal catalyst operation. However, the startup cycle for combustion equipment of this nature requires far less time than other types of combustion processes used to generate electricity.

During normal operation, BACT for CO is represented by an emission limit of 4 ppmv dry at 15percent oxygen based on a 24-hour rolling average and 24.71 pph based on a 24-hour rolling average for each CTG/HRSG train.

During SU/SD operations, each CTG/HRSG train is limited to 500 hours per 12-month rolling time period. BACT, for each CTG/HRSG train, is represented by an emission limit of 3,536.9 pph during startup and shutdown, which is based on an operating hour.

Compliance with the CO limits will be monitored using a CO and diluent CEMS.

During normal operation, BACT for VOC is represented by an emission limit of 4 ppmv dry at 15 percent oxygen for each CTG/HRSG train. During SU/SD operations, each CTG/HRSG trains is limited to 500 hours per 12-month rolling time period.

Compliance with the VOC limit will be determined through stack testing, and record keeping. Averaging times for the normal operation emission limit will be based on testing protocols. Michigan Air Pollution Control Rule 336.2003(5) requires that "Minimum sample time shall be 60 minutes, which may be continuous or a combination of shorter sampling periods for sources that operate in a cyclic manner." Compliance with the VOC emission limit will be based on a short-term average.

BACT for PM, PM10, and PM2.5
Particulate matter emissions from the combustion of natural gas depends on suspended particles in the combustion air, sulfates formed due to sulfur in the fuel, the products of incomplete combustion such as unburned carbon, and metallic oxides from degradation of internal turbine components. PM exists as a solid or liquid at temperatures of approximately 250°F and is considered the "filterable" or "front half" of particulate matter. PM10 and PM2.5 each includes both the "filterable" and "condensable" fraction of particulate matter and both were evaluated simultaneously. The "condensable" portion of PM10 and PM2.5 is particulate matter that exists as a solid or liquid at temperatures less than 32°F. It includes substances such as nitrogen compounds and sulfur compounds, which are in a vapor state at high temperatures, acid gases, VOCs, etc., but does not include condensed water vapor.
Indeck identified several combustion and post combustion control technologies for the control of PM, PM10, and PM2.5 emissions. The following technologies were identified and evaluated:

Combustion and Post Combustion Controls	• Pipeline Quality Natural Gas • Inlet Air Conditioning • Good Combustion Practices • Fabric Filter Baghouses • Dry Electrostatic Precipitators (ESPs) • Wet ESPs • Venturi Scrubbers

The review of each of these technologies is summarized below.

- Pipeline Quality Natural Gas does not contain ash or other large solid constituents, therefore it inherently will have extremely low filterable particulate emissions. The main form of particulate matter seen from the combustion of natural gas in CTG/HRSG units is condensable particulates, which are formed from the incomplete combustion of heavier weight hydrocarbons. The formation of particulate can also result from the oxidation of sulfur compounds, which can precipitate as particulate matter in the exhaust stream. Pipeline quality natural gas contains very low levels of sulfur; therefore, emissions of sulfur and the resulting PM, PM10, and PM2.5 are minimized through the use of this clean-burning fuel.

- Combustion turbines require an inlet air filtering system to remove particulates from the combustion air that would otherwise damage the CTG components. It also prevents unwanted contaminates from being discharged with the exhaust gases.

- PM, PM10, and PM2.5 emissions from natural gas combustion are inherently low, and good combustion practices can further minimize the amount of particulate generated due to incomplete combustion in the combined-cycle units. Optimization of the combustion chamber designs and operation practices that improve the oxidation process and minimize incomplete combustion are the primary mechanisms available for lowering emissions, and are often referred to as good combustion practices.

- A fabric filter baghouse removes filterable particulate from the flue gas using fabric filter bags. As the particulate laden gas passes through the bags, a layer of particulate called “filter cake” builds up on the bags which also act as a filtration device. Fabric filters can achieve high levels of PM, PM10, and PM2.5 control at greater than 99 percent (as high as 99.9+%) on a mass basis of filterable particulate. Fabric filter baghouses have several advantages when used for particulate control including high control efficiencies, relatively constant outlet grain loading over the load ranges, and simple operation and maintenance. Fabric filters are also considered to be the best technology for capturing fine filterable particulate. As natural gas combustion leads to mostly condensable particulate emissions, the high level of control would most likely not be reached.

- A dry ESP is a large enclosure filled with a series of fields which consist of negatively charged discharge electrodes and positively charged collection plates. The discharge electrodes negatively charge the particles in the gas stream which migrate to the positively charged plates. Particulate collected on the plates is periodically removed by rapping the plates. Factors affecting particulate collection efficiency of an ESP include gas flow rate through the ESP, total plate area, particulate resistivity, voltage, and the structure of the ESP. The smaller the collection area of the ESP, the narrower the acceptable resistivity range becomes. To optimize particulate resistivity and maximize collection efficiency, sulfur trioxide is injected to condition the ash and reduce particulate resistivity. ESPs have lower pressure drops across the control device than fabric filter baghouses which saves energy by reducing fan horsepower requirements, and therefore, the parasitic load on the generating unit. However, there is an increase in capital cost due to the significant additional electrical infrastructure required to support its operation. ESPs can achieve control efficiencies of greater than 99%.

- Wet ESPs are similar to dry ESPs with negative and positive charged fields that attract particles. However, in a wet ESP, the flue gas is cooled below the dew point and particulate matter may be present as either solid or liquid particles. Water droplets, other condensable materials (e.g., sulfuric acid), and fine particulate matter can be collected by the charged fields. The electrodes are flushed with water to remove collected materials. Wet ESPs would require an additional electrical, water supply, and wastewater treatment infrastructures.

- Venturi scrubbers remove particulate using several mechanisms, including condensation, inertial impaction of particulate with water droplets, and reactions of particulate and particulate precursors with the scrubber reagents. Venturi scrubbers would require an additional electrical, water supply, and wastewater treatment infrastructures. Particulate control efficiency in a venturi scrubber is variable depending on the scrubber design, particulate size, and particulate loading but control efficiency can be greater than 90%.

The use of pipeline quality natural gas, inlet air conditioning, and good combustion practices were used for the emission calculations. All reductions in emissions were with these potential control options already incorporated as baseline conditions. Indeck provided an economic analysis for the rest of the evaluated control technologies: fabric filter baghouses, dry and wet ESPs, and venturi scrubbers.

The cost analysis was performed conservatively for 100 percent capture of PM2.5, where PM10 calculations equaled PM2.5 and they were higher emitting than PM. Fabric filter baghouses were evaluated at the same capture efficiency, even though they would be less efficient with condensable particulate capture. Indeck calculated the total cost effectiveness, in units of dollars per ton of particulate removed, for each control technology (see below) and determined they were not economically feasible.

- Pulse Jet Fabric Filter Baghouse: minimum of $364,528 per ton
- Mechanical Shaker Fabric Filter Baghouse: minimum of $404,724 per ton
- Reverse-Air Fabric Filter Baghouse: minimum of $476,689 per ton
- Dry ESP (Wire-Plate Type): minimum of $478,806 per ton
- Dry ESP (Wire-Pipe Type): minimum of $303,809 per ton
- Wet ESP (Wire-Plate Type): minimum of $576,763 per ton
- Wet ESP (Wire-Pipe Type): minimum of $440,047 per ton
- Venturi Scrubber: minimum of $1,445,564 per ton

Based upon the above, Indeck proposed, and the AQD concurred, that BACT for PM, PM10, and PM2.5 is using pipeline quality natural gas, inlet air conditioning, and good combustion practices together with emission limits.

<u>PM</u>
Indeck proposes an emission limit of 9.9 pounds per hour (0.002 lb/MMBTU) for each CTG/HRSG train.

<u>PM10 and PM2.5</u>
Indeck proposes emission limits of 19.8 pounds per hour (0.005 lb/MMBTU), which includes startup and shutdown for each CTG/HRSG train.

Compliance with the PM, PM10, and PM2.5 limits will be determined through stack testing. Averaging times for the emission limit will be based on testing protocols. Michigan Air Pollution Control Rule 336.2003(5) requires that "Minimum sample time shall be 60 minutes, which may be continuous or a combination of shorter sampling periods for sources that operate in a cyclic manner." Compliance with the PM10 and PM2.5 emission limit will be based on a short-term average.

BACT for SO_2
SO_2 is emitted as a result of the thermal oxidation of the sulfur compounds in fuel. While only small amounts of sulfur are found in natural gas, the projected SO_2 emissions from this proposed project are subject to PSD and thus BACT. Indeck identified four possible technologies for the control of SO_2 emissions. The following technologies were identified and evaluated:

Combustion and Post Combustion Controls	• Flue Gas Desulfurization (FGD) • Fuel Desulfurization • Pipeline Quality Natural Gas • Good Combustion Practices

The review of each of these technologies is summarized below.

- FGD is a post-combustion control technology that uses a scrubbing liquid or dry reagent to absorb SO_2 present in the exhaust gas stream. It is most often used to control emissions from coal-fired boilers where there is much higher sulfur content. Traditionally designed as a wet system, FGD uses a scrubbing liquid containing an alkali reagent such as lime or limestone for the absorption of SO_2; however, there are dry systems that utilize calcium or sodium-based reagents followed by particulate control. This technology is considered a feasible control alternative for this project.

- There are several pre-treatment technologies available to remove sulfur from fuel prior to combustion. These processes use different technologies such as adsorption, biofiltration, scrubbers, Claus systems, and liquid or solid scavengers. These are typically used on fuels with much higher sulfur content than natural gas. As such, this technology is not considered a feasible control alternative for this project.

- Pipeline Quality Natural Gas contains the lowest sulfur content of any commercially available fuel. As such, its use is considered a feasible control alternative for this project.

The use of pipeline quality natural gas and good combustion practices were used for the emission calculations. All reductions in emissions were with these potential control options already incorporated as baseline conditions. Indeck provided an economic analysis for the FGD and it showed the costs to be uneconomical. AQD concurred with Indeck's evaluation.

Based upon the above information, Indeck proposed, that BACT for SO_2 is using pipeline quality natural gas and good combustion practices together with emission limits of 11.7 pounds per hour for each CTG/HRSG train. The AQD concurred with this analysis.

BACT for H_2SO_4

Sulfuric Acid Mist (H_2SO_4) is formed as a result of the reaction of sulfur trioxide (SO_3) with water, either in the flue gas stream or in the atmosphere after discharge. SO_3 is formed as a result of the thermal oxidation of sulfur compounds in the fuel. While only small amounts of sulfur are found in natural gas, the projected H_2SO_4 emissions from this proposed project are subject to PSD, and thus BACT. Indeck identified seven possible technologies for the control of SO_2 emissions. The following technologies were identified and evaluated:

Combustion and Post Combustion Controls	• FGD • Fuel Desulfurization • Wet ESPs • Hydrated Lime Injection • Sodium Bicarbonate Injection • Pipeline Quality Natural Gas • Good Combustion Practices

The review of each of these technologies is summarized below.

- FGD and fuel desulfurization each work to control H_2SO_4 emissions in the same ways they control SO_2 emissions. Again, FGD is considered a feasible control alternative for this project, whereas fuel desulfurization is not.

- Wet ESPs are primarily designed for control of condensable particulate emissions, and have been used on coal-fired generating sources that utilize high-sulfur fuels and have higher concentrations of inorganic condensable PM in the form of H_2SO_4 emissions. Wet ESP technology charges particles by the ions created by discharge electrodes subject to a high-voltage potential. The charged particles migrate to the positively grounded collecting plates. Water is sprayed onto the collecting plates and washes the collected particles from the surfaces. Since the particulate is removed by water, a means of utilizing the waterwash or additional waterwash treatment provisions is typically incorporated into a plant design associated with a Wet ESP.

- Hydrated lime is produced by combining lime with water to form calcium hydroxide ($Ca(OH)_2$). Typically hydrated lime injection is used in combination with a fabric filter and flue gas desulfurization to reduce SO_3. As there will be no fabric filter at this facility, the use of hydrated lime is not considered technically feasible.

- Sodium bicarbonate injection technology began with the use of sodium bisulfate injection but now uses sodium bicarbonate as the reagent. A sodium bicarbonate slurry is injected into the ductwork either upstream of the air heater or upstream of the fabric filter to reduce SO_3. This system requires significant maintenance and is very prone to plugging of the nozzles. That coupled with the fact that there will be no fabric filter at this facility, the use of sodium bicarbonate injection is not considered technically feasible.

The use of pipeline quality natural gas and good combustion practices were used for the emission calculations. All reductions in emissions were with these potential control options already incorporated as baseline conditions. Indeck provided an economic analysis for the FGD and it showed the costs to be uneconomical. AQD concurred with Indeck's evaluation.

Based upon the above, Indeck proposed, and the AQD concurred, that BACT for H_2SO_4 is using pipeline quality natural gas and good combustion practices together with emission limits of 4.6 pounds per hour for each CTG/HRSG train.

BACT for Greenhouse Gases (GHG)

GHGs are generated when fuel is combusted. GHGs are regulated as a single air pollutant defined as the aggregate mix of six well-mixed GHGs. The six GHGs are carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF_6). Some of these GHGs have a higher global warming potential than others. To address this, GHGs are converted to carbon dioxide equivalents (CO_2e) by using the gases' global warming potential. Total GHG emissions are calculated by summing the CO_2e emissions of all six constituent GHGs. Efficient combustion of natural gas results in conversion of almost all the fuel to CO_2, with only trace amounts of CH_4 and N_2O. No HFCs, PFCs, and SF_6 are produced with the combustion of natural gas. Since CH_4 and N_2O have higher global warming potential, less efficient combustion results in higher CO_2e emissions.

Indeck identified several combustion and post combustion control technologies for the control of GHGs. The following technologies were identified and evaluated:

Combustion and Post Combustion Controls	• Carbon Capture and Sequestration (CCS) • Low Carbon Fuel • Energy Efficiency Measures

The review of each of these technologies is summarized below.

- Carbon capture and sequestration (CCS) is a multiple-step process: capture of the CO_2 from the flue gas, transportation of CO_2 emissions, and long-term storage of the captured CO_2, or sequestration. Capture and sequestration are evaluated separately to determine feasible solutions for each step of the CCS process. Each step of the process is described in detail below.

  – **Carbon Capture**
    Carbon capture is the separation of CO_2 from the flue gas before it is emitted through the exhaust stack from the facility. Capture systems being developed are expected to collect up to 90 percent of flue gas CO_2. Currently, absorption technology is the most feasible technology for carbon capture and is considered an available technology. The most developed is the amine- and ammonia-based absorption technologies. However, the process of separating CO_2 from the flue gas has high energy demand and is cost intensive. Therefore, the addition of a carbon capture system would reduce the net generating capacity of the proposed combined-cycle operation.

    An amine-based CO_2 stripping process for the capture system was evaluated, which is composed of three main functional areas: flue gas pretreatment (cooling/polishing scrubber), CO2 absorption/stripping, and CO2 compression. The following sections briefly describe each of these process steps.

    Flue Gas Pretreatment
    In the pretreatment step, flue gas leaves the HRSGs and is directed through a cooler/polishing scrubber to reduce the gas temperature, and remove residual acid gases and particulate that are contaminants to the overall process. The flue gas temperature is lowered to approximately 120°F, or less, for proper operation of the amine absorber. The residual acid gases are removed to minimize degradation of the amine solvent, and particulates need to be removed to prevent the plugging of packed beds and heat exchanger surfaces. For a NGCC plant, it is possible that the polishing scrubber may not be needed because of the cleaner flue gas; however, preliminary flowsheets of CCS systems for NGCC application typically show a polishing scrubber.

    It is anticipated that flue gas booster fans would be required to pressurize the flue gas to overcome added pressure loss as the flue gas passes through the pretreatment and absorption processes of the CCS system and interconnecting ductwork.

    CO2 Absorption/Stripping
    In the absorption/stripping process, CO_2 is removed from the flue gas in the absorber by the amine solvent. The absorbers would likely have packed beds to enhance removal performance. Lean amine solvent enters the top of the CO_2 absorber. As the amine solvent flows through the packed beds of the absorber, it contacts the counter-current flowing flue gas. CO_2 is absorbed by the amine solvent which is collected in the bottom of the CO_2 absorber. The CO_2-rich amine solvent is heated and pumped to the CO_2 stripper for regeneration. The flue gas leaves the CO_2 absorber and is discharged through the exhaust stack. A key concern is that losses of amine solvent as carryover from the absorber in the flue gas be minimized.

    CO_2 is separated from the rich amine solvent in the CO_2 regenerators, which are steam stripping towers, containing packed beds. The CO_2-rich solvent flows from the top of the regenerator to the bottom and is contacted with steam, releasing CO_2 into the gas phase. The top bed of the regenerator is washed using water to remove entrained amine solvent from the exiting CO_2/steam mixture. The lean amine solvent, collected in the bottom of the CO_2 regenerator is cooled through a heat exchanger and returned to the CO_2 absorber.

CO2 Compression
Captured CO_2 that is exhausted from the CO_2 stripper/solvent regeneration towers is compressed to high pressure (approximately 1,500 psig) by staged compressors with interstage cooling/drying. The compressed CO_2 is then further pressurized via high pressure pumps to 2,200 psig or greater for pipeline transport to a sequestration site for injection.

– **Transportation of CO_2 emissions**
Captured CO_2 emissions would have to be transported to a storage site via a pipeline.

– **Carbon Sequestration**
Sequestration is the long term isolation of CO_2 from the atmosphere through physical, chemical, biological, or engineered processes. Geological sequestration is a sequestration technique involving the storage of captured CO_2 in a location where it will not readily escape into the atmosphere. Current technology involves the use of deep underground rock formations where the extreme pressure and temperatures cause the CO_2 to enter the liquid phase, and can be used for enhanced oil recovery (EOR). Injected CO_2 occupies pore spaces in the surrounding rock. Saline water residing in the pore space will be displaced by the CO_2. The CO_2 also dissolves in water and chemical reactions between the dissolved CO_2 and rock create solid carbonate minerals which trap CO_2.

- Low carbon fuel aid in minimizing the amount of GHG emissions produced during combustion. Indeck proposes using pipeline quality natural gas for turbine and duct burner combustion. Pipeline quality natural gas has a carbon content of 34 pounds carbon per MMBTU, whereas fuel oil is 48 lb/MMBTU. Only biogas (captured methane) and coke oven gas (COG) result in lower CO_2 per heat input than natural gas, neither of which are within the design definition of this project. Therefore, Indeck will use the lowest carbon fuel available, allowing for minimal GHG emissions.
- Energy efficiency measures in a combustion process minimize the use of fuel through maximizing energy output. The more complete the combustion, the higher the energy output.

The use of pipeline quality natural gas and energy efficiency measures were used for the emission calculations. All reductions in emissions were with these potential control options already incorporated as baseline conditions. Indeck provided an economic analysis for carbon capture and sequestration.

The use of CCS technology entails a significant economic impact on the proposed facility. Indeck used a report published by Energy and Environmental Economics, Inc. and reports published by the Department of Energy, National Energy Research Laboratory to evaluate the economic impact.

The amine-based CCS technologies were used since these are generally considered to be the most feasible near-term deployable technology for possible future CO_2 removal. To estimate the theoretical capital cost of CCS for the proposed project, a range of \$800/kW to \$1,150/kW based upon heat rates of 9,200-10,500 BTU/kW-hr was used, these ranges equate to approximately \$76,190-125,000/(MMBTU/hr). Indeck used a facility-wide heat input of 8,257 MMBTU/hr in their calculations; variations in this calculation and the addition of the space heaters (which were not listed in the original application) could yield a heat input of up to 8,565 MMBTU/hr. However, using a lower MMBTU/hr value yields more conservative results, so the Indeck values are relayed for this evaluation. The cost values are in the range of other CCS BACT analyses. Using the lowest capital cost range, the estimated capital cost for CCS for the proposed project is approximately \$629,000,000. The cost of a pipeline to transport the CO_2 was added to the result to estimate the total capital cost of the CO_2 control system. The operating and maintenance and indirect operating costs were estimated to be around \$53,000,000. Based on 90 percent CO_2 removal and the control being applied to the facility-wide emissions, not just the CTG/HRSG trains, the resulting cost is estimated to be \$30/ton and was determined by Indeck to not be considered economically feasible. The AQD concurs with this conclusion.

Therefore, Indeck selected using a low carbon fuel (pipeline quality natural gas) and energy efficiency measures as BACT for this project. Energy efficiency measures involve the installation of combined cycle units, following vendor recommended maintenance practices, the minimization of heat loss, fuel gas preheating, and efficient heat exchanger design, insulation of the HRSGs, and automated instrumentation and controls for efficient combustion. A natural gas-fired combined-cycle operation is expected to have a thermal efficiency of approximately 50 to 60 percent on a higher heating value (HHV) basis at ISO conditions.

BACT is represented by an emission limit or work practice standard. As BACT for GHG has been determined to be energy efficiency, Indeck is proposing a 2,097,001 (short) tons CO_2e per year limit for each CTG/HRSG train, on a 12-month rolling average. Compliance with the 12-month rolling CO_2e emission limits will be based upon fuel usage monitoring and calculations. The proposed permit also contains a net output limit of 802 lb CO_2 per MW-hour (lb/MWh) (equivalent to a net heat rate of 6,855 Btu/kW-hr per 2x1 block), which is more stringent than the 1,000 lb/MWh limit allowed by NSPS Subpart TTTT. The net output limit will require emission data and electrical output data to demonstrate compliance.

The table below is a summary of the PSD BACT emission limits discussed above.

CTG/HRSG Train Emission Limit Summary

Pollutant	**PSD BACT Limits**			**Annual Equivalent Emissions**
	ppmvd at 15% O_2	**pph**	**lb/MWh**	**tpy**
NO_x	3*	38.1* 286**	----	494 tpy***
CO	4	24.7* 3,537**	----	2,009 tpy***
PM	----	9.9	----	91.2 tpy
PM10	----	19.8	----	181 tpy
PM2.5	----	19.8	----	181 tpy
SO_2	----	11.7	----	103 tpy
VOC	4	----	----	948 tpy***
H_2SO_4	----	4.6	----	40.2 tpy
GHGs as CO_2e	----	----	----	4,302,486 tpy
CO_2	----	----	802	4,189,743 tpy (BACT limit)
*Except during startup and shutdown. **During startup and shutdown. ***These emissions include 500 hours of startup and shutdown operation for the CTG/HRSG trains.				

Auxiliary Equipment

A top-down PSD BACT analysis was performed for all of the other proposed auxiliary equipment, which includes the auxiliary boiler, fuel heaters, emergency engine, fire pump engine, diesel tanks, space heaters, cold cleaner and fugitive emissions. The complete PSD BACT analyses for these units are contained in the application file and are available for public review. Below is a summary of the analysis and the proposed limits, design requirements, and/or work practice determined under it for these units:

Auxiliary Boiler, Fuel Heaters, Emergency Engine, and Fire Pump Engine

Good combustion practices will be utilized in all fuel-burning auxiliary equipment.

- **Auxiliary Boiler and Fuel Heaters**

  Indeck reviewed combustion modification and post-combustion control, or a combination, for technical feasibility. For NO_x, the controls considered technically feasible were LNB, FGR, and SCR. For CO and VOC, the control considered technically feasible was catalytic oxidation. For the other pollutants, PM, PM10, PM2.5, and SO_2, Indeck did not consider additional controls to be applicable for such small emitters. The GHG emissions were included in the cost analysis described under the CTG/HRSG trains.

  The auxiliary boiler will be equipped with inherent NO_x control of LNB and FGR and no additional control is proposed for any other pollutants, so that was considered the baseline conditions for the cost analyses. No control was proposed for the fuel heaters for any pollutants, so that was considered the baseline conditions for the cost analyses. Indeck determined that no further control was economical for the auxiliary boiler and that no control was technically or economically feasible for the fuel heaters. The condition limiting the fuel heaters to the equivalent of only one operating at a time was taken into account for the cost analysis. It was also determined that add-on controls for PM, PM10, PM2.5, and SO_2 were not cost effective.

  The following is a summary of the proposed PSD BACT limits for these units:

Auxiliary Boiler

Pollutant	PSD BACT Limits		Annual Equivalent Emissions
	lb/MMBTU heat input	pph	tpy
NO_x	0.04	----	31.89
CO	0.04	----	31.89
PM	0.005	----	3.99
PM10	----	1.36	5.94
PM2.5	----	1.36	5.94
SO_2	0.6*	----	0.47
VOC	0.004	----	3.19
GHGs as CO_2e	----	----	93,346 (BACT limit)
*SO_2 limit is in lb/MMscf.			

Fuel Heater

Pollutant	PSD BACT Limits, each unit		Annual Equivalent Emissions
	lb/MMBTU heat input	pph	tpy
NO_x	----	2.65	11.59
CO	----	2.22	9.74
PM	0.002	----	0.22
PM10	----	0.20	0.88
PM2.5	----	0.20	0.88
VOC	----	0.15	0.64
GHGs as CO_2e	----	----	13,848 (BACT limit)*
*GHG limit is for both fuel heaters together.			

– **Emergency Engine and Fire Pump Engine**

Indeck reviewed post-combustion control for technical feasibility. The control options were similar to the CTG/HRSG trains. Use of ultra-low sulfur diesel with a maximum sulfur content of 15 ppm (0.0015 percent) by weight was considered BACT and was the baseline conditions for further analysis. No control was proposed for either the emergency engine or the fire pump engine for any pollutants, so that was considered the baseline conditions for the cost analyses. Indeck determined that no further control was technically or economically feasible for the engines. The cost analysis for each unit took into account the maximum hours of operation allowed in the draft permit. For CO and VOC, the control considered technically feasible was catalytic oxidation. For the other pollutants, NO_x, PM, PM10, PM2.5, and SO_2, Indeck did not consider the additional control to be technically feasible; many controls don't function properly for small emitters and intermittent sources. The GHG emissions were included in the cost analysis described under the CTG/HRSG trains.

The following is a summary of the proposed PSD BACT limits for these units:

Emergency Engine

Pollutant	PSD BACT Limits		Annual Equivalent Emissions
	g/kW-hr	pph	tpy*
NMHC+NO_X	6.4	----	7.69
CO	3.5	----	4.20
PM	0.20	----	0.24
PM10	----	1.58	0.40
PM2.5	----	1.58	0.40
VOC	----	1.87	0.47
GHG as CO_2e	----	----	928 (BACT Limit)
*Based on an annual maximum of 500 hours per 12-month rolling time period.			

Fire Pump Engine

Pollutant	PSD BACT Limits		Annual Equivalent Emissions
	g/bhp-hr	pph	tpy*
NMHC+NO_X	3.0	----	0.09
CO	2.6	----	7.45E-2
PM	0.15	----	4.30E-3
PM10	----	0.57	0.03
PM2.5	----	0.57	0.03
VOC	----	0.64	0.03
GHG as CO_2e	----	----	13.58 (BACT Limit)
*Based on an annual maximum of 100 hours per 12-month rolling time period.			

Diesel Tanks, Space Heaters, Cold Cleaner, and Fugitive Emissions

The Michigan Air Pollution Control Rules contain equipment or scenarios that may be exempt from getting a PTI; however, those exemptions may not be used when the equipment is in conjunction with a project that has triggered PSD review. The diesel tanks, space heaters, and cold cleaner may have met exemption requirements had this been a minor permitting action; they are considered to be small sources of emissions and subsequently do not have emission limits.

The diesel tanks are proposed to have conservation vent valves for VOC control; this is consistent with other permitting actions for small, low-emitting tanks. No other pollutants will be emitted from those tanks. Likewise only VOCs will be emitted from the cold cleaner. Indeck is required to keep the cover on this unit closed when not in use; this is consistent with the State of Michigan minor source BACT requirements for VOC emissions in Air Pollution Control Rule R 336.1707(3)(a) (Rule 707(3)(a)). There is no control proposed for the space heaters, which have a combined heat input limit of 10 MMBTU/hr. The control options would be the same as for the auxiliary boiler and fuel heaters, but at such a smaller size, the technologies would not be considered economically feasible.