Commonwealth of Kentucky
Division for Air Quality
STATEMENT OF BASIS

Title V / Title IV / Title I - PSD, CAIR, CSAPR
Final Permit: V-14-011 R1
HenderSun Generating Station
Kentucky State Highway 1078, Henderson County, Kentucky
August 11, 2015
Stuart Ecton, Reviewer

SOURCE ID:	21-101-00134
AGENCY INTEREST:	40285
ACTIVITY:	APE20150003

ADMINISTRATIVE PERMIT AMENDMENT – V-14-011 R1:

On July 6, 2015, the Division received an application for an administrative amendment to change the name of the source from Cash Creek Generating Station to HenderSun Generating Station and to change the permittee name to HenderSun Energy, L.L.C. On July 10, 2015, the Division deemed the application complete. The permit has been revised accordingly.

SOURCE DESCRIPTION:

Cash Creek Generation, L.L.C. (Cash Creek) proposes to construct a natural gas fired combined cycle power plant on Kentucky State Highway 1078 in Henderson County, Kentucky. The project will be comprised of two combined cycle combustion turbines (CTs), each equipped with a heat recovery steam generator (HRSG) and duct firing. Each CT will each drive an electric generator and the two HRSGs, in combination, will drive a third electric generator with steam. The duct firing will produce additional steam for electric generation.

The emissions from the CTs and duct burners will be vented through the HRSG stacks. Each stack will be 199 feet tall and the exhaust temperature will be at 177 ^{0}F.

The only fuel permitted to be used will be pipeline quality natural gas with a sulfur content of less than or equal to 1.0 grains/100 dscf.

Affected Facilities proposed to be permitted are listed below:

1. Emission Unit: (CT-1) Combined Cycle Combustion Turbine 1 equipped with a Heat Recovery Steam Generator (HRSG1) with Duct Firing

2. Emission Unit: (CT-2) Combined Cycle Combustion Turbine 2 equipped with a Heat Recovery Steam Generator (HRSG2) with Duct Firing

<u>Description:</u>

The two CTs and associated HRSGs will produce electrical power for sale. The units are not lean premix or diffusion flame, and do not use water or steam injection for control of nitrogen oxides (NO_x). The HRSGs utilize the hot flue gas from the combustion of natural gas in the CTs to produce steam to power a single steam turbine for additional electrical power output. Each HRSG is also equipped with a duct burner.

Fuel Input:	2,468 million British thermal units per hour (mmBtu/hr) Higher Heating Value (HHV), each turbine. 889 mmBtu/hr HHV each duct burner.
Fuel:	Pipeline Quality Natural gas only.
Power Output:	Approximately 231.9 megawatt (MW) from each turbine at 0 degrees Fahrenheit (does not include power from the steam turbine electric generator).

Maximum Fuel Input for entire facility (includes duct firing): 6,714 mmBTU/hr HHV

Maximum Gross Output for entire facility: 849 MW @ 0^0F

Control Equipment: Selective catalytic reduction (SCR) and low NO_x burners for 90% control of NO_x emissions.
Catalytic Oxidizer for 60% control of VOC and 90% control of CO.

3. Emission Unit: (CWTR-1 through CWTR-14) Fourteen Cell Cooling Tower

Description:

The cooling tower is a forced induction 14 cell cooling tower.
Capacity: 12.7 mmgal/hr circulation rate.
Control Equipment: High Efficiency Mist Eliminators ($PM/PM_{10}/PM_{2.5}$).

4. Insignificant Activities:

Description:

Emission Units: (CCD1), (TK-1), (SLINE1)

a. Maintenance Cold Cleaner (CCD1) subject to 401 KAR 63:020.
b. Aqueous Ammonia (20%) 27,000 gallon storage tank (TK-1) subject to 401 KAR 63:020.
c. Paved Haul Road (SLINE1) subject to 401 KAR 63:010.

ACRONYMS

VOC	Volatile Organic Compounds
PM	Particulate Matter
PM_{10}	Particulate Matter with an aerodynamic diameter of less than or equal to10 microns
$PM_{2.5}$	Particulate Matter with an aerodynamic diameter of less than or equal to2.5 microns
SO_2	Sulfur Dioxide
NO_x	Nitrogen Oxides
CO	Carbon Monoxide
CO_2	Carbon Dioxide
CO_{2e}	Carbon Dioxide equivalent (GHG)
H_2SO_4	Sulfuric Acid mist

H_2S	Hydrogen sulfide
Pb	Lead

APPLICABLE REGULATIONS:

401 KAR 51:017 – Prevention of significant deterioration of air quality (PSD). This regulation is applicable with respect to PM, PM_{10}, $PM_{2.5}$, SO_2, NO_x, CO, and CO_{2e} emissions from a new major stationary source that commenced after September 22, 1982.

401 KAR 60:005, 40 C.F.R. 60, Standards of performance for new stationary sources, incorporating by reference 40 CFR 60, Subpart KKKK - Standards of Performance for Stationary Combustion Turbines. This regulation is applicable to NO_x and SO_2 emissions from stationary combustion turbines with a heat input at peak load equal to or greater than 10.7 gigajoules (10 mmBtu) per hour that commenced construction, modification or reconstruction after February 18, 2005.

40 C.F.R. Part 75, Continuous Emission Monitoring. This regulation is applicable to continuous emissions monitoring system (CEMS) for NO_x and SO_2.

40 C.F.R. Part 97, Subpart AAAAA, TR NO_x Annual Trading Program.

40 C.F.R. Part 97, Subpart BBBBB, TR NO_x Ozone Season Trading Program.

40 C.F.R. 97, Subpart CCCCC, TR SO_2 Group 1 Trading Program.

401 KAR 63:010 – Fugitive emissions. This regulation is applicable with respect to particulate matter fugitive emissions from the source.

STATE-ORIGIN REQUIREMENTS:

401 KAR 63:020 – Potentially hazardous matter or toxic substances. This regulation is applicable to an emission unit which emits or may emit potentially hazardous matter or toxic substances, provided such emissions are not elsewhere subject to the provisions of the administrative regulations of the Division. Refer to SECTION B of the permit for operating limitations and compliance demonstration method.

NON-APPLICABLE REGULATIONS:

401 KAR 60:005, 40 C.F.R. 60, Standards of performance for new stationary sources, incorporating by reference:
40 CFR 60, Subpart GG - Standards of performance for stationary gas turbines;
40 CFR 60, Subpart Da - Standards of performance for electric Utility Steam Generating Units;
40 CFR 60, Subpart Db - Standards of performance for industrial-commercial-institutional steam generating units, or
40 CFR 60, Subpart Dc - Standards of performance for small industrial-commercial-institutional steam generating units.
Pursuant to 40 CFR 60.4305(b), combustion turbines are exempt from the requirements of 40

CFR 60, Subpart GG, and recovery steam generators and duct burners regulated under 40 CFR 60, Subpart KKKK, are exempt from the requirements of 40 CFR 60, Subparts Da, Db, and Dc.

40 C.F.R. Part 64, Compliance Assurance Monitoring (CAM). This regulation is not applicable because CEMS for CO are being installed pursuant to 401 KAR 51:017and operated in accordance with 40 CFR Part 75. CO is exempt from this part pursuant to 40 CFR 64.2 (3)(b)(vi).

401 KAR 63:002, 40 C.F.R. 63, National Emission Standards for Hazardous Air Pollutants incorporating by reference 40 CFR 63, Subpart Q - National Emission Standards for Hazardous Air Pollutants for Industrial Process Cooling Towers. This regulation is not applicable as long as the cooling towers are not operated with chromium-based water treatment chemicals.

401 KAR 63:002, 40 C.F.R. 63, National Emission Standards for Hazardous Air Pollutants, incorporating by reference 40 CFR 63, Subpart YYYY - National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines. This regulation applies to major sources of hazardous air pollutants. The potential to emit any HAP is less than 10 tons per year and less than 25 tons per year for any combination of HAPs.

PRECLUDED REGULATIONS:

The source has voluntarily taken federally enforceable operating limits that lower the potential to emit below the applicability threshold of 40 tons per year for VOC, hence 401 KAR 51:017 has been precluded with respect to this pollutant.

EMISSION AND OPERATING CAPS DESCRIPTION:

EMISSION CAP:

VOC emissions are limited to 38.1 tons per year to preclude applicability of PSD. See Sections D 2, D 3 and D 4 of the permit.

OPERATING LIMITATIONS:

In Section B 1 of the permit, there are additional operating limitations:

1. The permittee has voluntarily taken limits on hours of operation as described here. The total hours of operation of each turbine are limited to 8,584 hours per year. The hours of operation for each duct burner will be limited to 4,380 hours per year. This will ensure that VOC emission will not equal or exceed the PSD the applicability threshold of 40 tons per year. The potential to emit was based on these hours of operation.

2. Startup limits:
   A cold startup is when both CTs are idle. The startup of the first CT takes 4 hours and the startup of the second takes two hours. The second CT has a shorter startup time due to the fact some of the heat from the first CT is used to preheat it.

A warm startup is when one CT is operating at steady state and the other is idle. A warm startup takes only two hours because heat from the running CT can be used to preheat the idle CT thus shortening the time it takes to get it up and running at steady state.

Total cold startups are limited to 100 per year. Each cold startup is limited to 6 hours. Each warm startup is limited to 2 hours. Total warm startups are limited to 20 per year.

The air dispersion analysis required by PSD included the above startup scenario (number of warm & cold startups) to demonstrate compliance with all applicable NAAQS and increment consumption limits.

3. The permittee shall use only pipeline quality natural gas with a sulfur content of less than or equal to 1.0 grains/100 dscf. Natural gas is any fuel that meets the definition of natural gas in 40 CFR 60.4420. This limits potential SO_2 and CO_2 emissions.

4. The combustion turbines will be equipped with Low NO_x burners and SCR for control of NO_x; a Catalytic Oxidizer for control of CO and VOC emissions.

5. The permittee is authorized to combust only pipeline quality natural gas fuel for control of SO_2, H_2SO_4 mist, VOC, and PM/PM_{10}/$PM_{2.5}$.

6. Either combustion turbine is prohibited from operating at a firing rate less than 50 percent of the rated capacity on an hourly basis, except during periods of startup and shutdown events. 50 percent load represents the worst case scenario for the potential emissions of the pollutants that will be emitted. All modelling analysis was based on this loading.

7. The cooling tower will be required to be equipped with drift eliminators for control of PM/PM_{10}/$PM_{2.5}$.

PERIODIC MONITORING:

1. Pursuant to 401 KAR 51:017, and 40 CFR 60, Subpart KKKK, 60.4340(b), the permittee must install, calibrate, maintain and operate a NO_x CEMS as described in 40 CFR 60.4335(b) and 40 CFR 60.4345. This requirement will serve as the means to demonstrate compliance with the NO_x emission limitations.

2. Pursuant to 401 KAR 51:017 and 40 CFR Part 75 the permittee shall install, calibrate, maintain, and operate a CO CEMS. This requirement will serve as the means to demonstrate compliance with the CO emission limitations.

3. The permittee shall install, calibrate, operate, test, and monitor all continuous monitoring systems and monitor devices in accordance with the schedule for Quality Assurance Procedures as specified in appendix B of 40 CFR Part 75. This requirement ensures that all CEMs are properly installed, operated, and maintained.

4. For compliance with 1. Operating Limitations c. of the permit for emission units CT-1 and CT-2, a metering system shall be installed and operated to accurately measure natural gas being fired in

each combustion turbine on an hourly basis.

5. The permittee shall maintain records onsite showing fuel characteristics in a current, valid purchase contract, tariff sheet or transportation contract for the fuel, specifying the fuels major constituents and heat value. The pipeline quality natural gas shall be certified with sulfur content of less than 1.0 grains per 100 dscf. This requirement will serve as a means to demonstrate compliance with the SO_2 emission limitations.

6. The permittee shall evaluate the relationship between CO and VOC during the initial stack tests. Results of this evaluation shall be submitted to the Division within sixty days after submitting the test results. If no additional stack tests are performed pursuant to this permit, the permittee shall conduct a performance test to reestablish the relationship between CO and VOC by the start of the fourth year of this permit to demonstrate compliance with the applicable standard. This requirement will serve as a means to demonstrate compliance with the VOC synthetic minor emission limit of 38.1 tons per year.

7. The CO_2 Monitoring, Recordkeeping, and Reporting requirements are applied as proposed amendments of 40 CFR 60, Subpart KKKK published in the Federal Register on January 8, 2014 (Vol. 79, No.5).

PSD APPLICABILITY:

PSD applies to new and modified major stationary sources as defined in 401 KAR 51:001. With respect to fossil fuel-fired steam electric plants of more than 250 million Btu/hr of heat input is a "major stationary source" subject to PSD review if it emits 100 tons per year or more (based on potential to emit for new units) of any regulated NSR pollutant and is located in an area designated to be in attainment for that pollutant (401 KAR 51:017). Once PSD is triggered for a pollutant, all of the other regulated pollutants will be subject to a PSD review if the emission increase is over the Significant Emission Rate for that pollutant.

Significant Emission Rate is defined in 401 KAR 51:001, Definitions, Section 1 (218) and is listed below for each pollutant. The annual potential emissions are based on 100% CT loads with duct burners in operation and 120 startups (100 cold and 20 warm). This is the worst case scenario with regard to potential to emit.

Table 1: PSD Applicability

Pollutant	Potential Emissions (tons/year)	PSD Significant Emission Rate (tons/year)	Pollutant Subject to PSD Review?
PM	217.58	25	YES
PM_{10}	214.53	15	YES
$PM_{2.5}$	214.53	15	YES
SO_2	67.65	40	YES
NO_x	233.51	40	YES
CO	215.04	100	YES
VOC	38.10	40	NO
H_2SO_4 mist	10.24	7	YES
H_2S	0.0	10	NO
Lead (Pb)	ND (AP-42)	0.6	NO
CO_{2e}	2,941,625	100,000	YES

BACT DETERMINATION:

BACT is defined in 401 KAR 51:001, section 1(25) as follows:

"*Best available control technology" or "BACT" means an emissions limitation, including a visible emission standard, based on the maximum degree of reduction for each regulated NSR pollutant that will be emitted from a proposed major stationary source or major modification and:*

(a) Is determined by the cabinet pursuant to 401 KAR 51:017, Section 8, after taking into account energy, environmental, and economic impacts and other costs, to be achievable by the source or modification through application of production processes or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of that pollutant;

(b) Does not result in emissions of a pollutant that would exceed the emissions allowed by an applicable standard codified in 40 C.F.R. Parts 60 and 61; and

(c) Is satisfied by a design, equipment, work practice, or operational standard or combination of

standards approved by the cabinet, if:

1. The cabinet determines pursuant to 40 C.F.R. 51.166(b)(12) that technological or economic limitations on the application of measurement methodology to a particular emissions unit would make the imposition of an emissions standard infeasible;

2. The standard establishes the emissions reduction achievable by implementation of the design, equipment, work practice, or operation; and

3. The standard provides for compliance by means that achieve equivalent results.

The most important aspects of this definition are summarized below:

- BACT is expressed as an emission limitation based on the maximum degree of emission reduction of criteria pollutants.

- BACT must be “available” and “feasible”. An “available” technology is one that is commercially available; meaning is has advanced through the initial research and development phase of bench scale testing, lab testing, pilot scale testing, licensing, has fully achieved commercial size demonstration, and has established commercial sales without direct government subsidy. “Feasible” not only involves the commercial availability but also involves consideration of the physical and chemical properties of the emissions to be controlled. An applicant should be able to purchase or construct a process or control device that has been demonstrated in practice.

- The permitting agency must consider BACT on a case by case basis taking into account technological feasibility, energy, environmental and economic impacts to determine whether the given technology is “feasible” for the project.

The applicant has followed a process of selecting controls using methodology summarized as follows:

1. Identify all control strategies.
2. Eliminate technically infeasible options.
3. Rank remaining control technologies by control effectiveness (highest to lowest)
4. Evaluate economic, environmental, and energy impacts of the most effective controls. This is otherwise known as a “Top-Down” analysis.
5. Select BACT.

The emission units proposed at the source that were considered in this BACT analysis are the two CT’s each equipped with a HRSG with duct burning (emission units CT-1 and CT-2), and the fourteen cell Cooling Tower (emission units CTWR-1 through CTWR-14).

1. <u>Identify all control strategies</u>:

Table 2: Control strategies

Pollutant	Control Technologies for Combustion Turbines
$PM/PM_{10}/PM_{2.5}$	Use of Pipeline quality natural gas fuel Post Combustion: Baghouse Electrostatic Precipitator Wet Electrostatic Precipitator Scrubbers Cyclone
SO_2	Use of Pipeline quality natural gas fuel Post Combustion Scrubber (Wet or Dry)
NO_x	Dry Low NO_x Burners Water Injection Steam Injection Post Combustion: Selective Catalytic Reduction Selective Non-catalytic Reduction $SCONO_x$
CO	Excess Air Carbon Monoxide Catalytic Oxidation Thermal Oxidation Proper Design and Operation
H_2SO_4 mist	Use of Pipeline quality natural gas fuel Post Combustion Scrubber (Wet or Dry)
CO_{2e}	Use of Pipeline quality natural gas fuel Carbon Capture and Sequestration Enhanced Energy Efficiency

Table 2 (continued)

Pollutant	Control Technologies for Cooling Towers
$PM/PM_{10}/PM_{2.5}$	Drift Eliminators Dry Cooling Towers
SO_2	NA
NO_x	NA
CO	NA
H_2SO_4 mist	NA
CO_{2e}	NA

The above listing of control strategies were compiled from the RACT/ BACT/ LAER/ CLEARINGHOUSE (RBLC) and from other available literature regarding pollution controls for CTs and ancillary equipment.

2. Eliminate technically infeasible options:

For Combustion Turbines:

$PM/PM_{10}/PM_{2.5}$:

Controls normally associated particulate matter are Baghouses, Electrostatic Precipitators, Wet Electrostatic Precipitators, Scrubbers, and Cyclones. The use of these technologies have not been demonstrated to be technically feasible on combustion turbines due to the physical characteristics of the exhaust stream such as very low particulate loading. This is the case when only firing pipeline quality natural gas. Use of clean fuels (in this case pipeline quality natural gas) has been demonstrated as an extremely effective operating method to control particulate emissions. Pipeline quality natural gas contains extremely small amounts of particulate matter and combustion of this fuel results in much lower emissions than any other commercially available fossil fuel (AP-42).

SO_2/ H_2SO_4:

Post combustion controls like wet and dry scrubbers have been proven to be very effective in controlling SO_2 and H_2SO_4 emissions. However, post combustion controls are not feasible due to the very low sulfur loading of the exhaust stream if (1.0 grains per 100 dscf) sulfur content of pipeline quality natural gas is used exclusively. Use of clean fuels (those with very low sulfur content e.g.) has been demonstrated as an extremely effective operating method to control SO_2 and H_2SO_4.

NO_x:

Pre combustion controls like Dry Low NO_x Burners (DLNB), Water Injection, Steam Injection as well as post combustion controls such as Selective Catalytic Reduction (SCR), Selective Non-catalytic Reduction (SNCR), and $SCONO_x$ have been successfully used for control of NO_x for various processes that combust fossil fuels.

A search of the RLBC shows no large (849 MW) CTs are using or are proposing the use the $SCONO_x$. The technology performs well for smaller CTs but is technically infeasible for units as large as those being proposed by the source. The main advantage of $SCONO_x$ is that no ammonia is used in the process, due to the unique properties of the catalyst, therefore eliminating ammonia slip which does occur with the use of SCR.

Water/Steam injection is the direct injection into the combustor of the turbine to reduce the temperature and thus the formation of thermal NO_x. However, this method of control can disrupt turbine operation by adversely affecting flame stability for example. In addition, the overwhelming majority of CTs in operation or being proposed are not implementing this technology which is, in fact, less effective than other control strategies.

SNCR is effective in reducing post combustion NO_x via ammonia or urea injection similar to SCR but without a catalyst. However, more ammonia is needed to control NO_x and this increases ammonia slip.
DLNB are proven over a large range of CT size and are used in most existing and proposed CTs.

These burners enable a temperature reduction in the combustion zone and, therefore, limit the formation of thermal NO_x. In addition, CT vendors have developed specific DLNB technologies for each CT class and include them as part of their base design.

SCR employs a catalyst which will allow for lower temperatures, less NO_x formation and, therefore, lower ammonia use.

CO:

Excess Air, Carbon Monoxide Catalytic Oxidizers, Proper design and Operation, and Thermal Oxidation have been proven to reduce CO emissions. However catalytic oxidation of CO offers high efficiency at lower temperatures and, therefore less thermal stress on the equipment. Thermal Oxidation, on the other hand, requires higher temperatures and results in increased emissions of other criteria pollutants resulting from combustion of a fuel to provide the higher temperatures for equivalent CO control (oxidation to CO_2).

CO_2:

Carbon Capture and Sequestration (CCS).
This method of CO_2 control consists of three basic steps:

- Capturing and separating CO_2 from the exhaust stream.
- Transporting the CO_2 to a permanent geological storage site.
- Permanently storing the gas.

CCS is not currently feasible for CT electric generating stations like the one proposed by the source. While there is active research and development, there are no CCS systems commercially available for any full scale CT in the United States.

In order for CCS to be technically feasible, all three of the basic steps must be demonstrated and commercially available for similar CT power plants.

Use of clean fuel and energy efficiency are the only technically feasible options to control CO_{2e} emissions that presently exist.

For the Cooling Tower:

$PM/PM_{10}/PM_{2.5}$:

The CT process proposed by the source will produce large amounts of heat that will be transferred to process cooling water in the steam turbine condenser. The process cooling water must then release heat to the atmosphere in order to function as a closed loop heat transfer media. The most effective way of releasing heat to the atmosphere from the cooling water is by using a wet vertical cooling tower.

$PM/PM_{10}/PM_{2.5}$ emissions are produced by cooling towers from water entrained in the air stream passing through the tower. The water and the associated particulate matter is pushed into the atmosphere and are commonly known as "drift." The PM is this drift is primarily composed of impurities that are present in the cooling tower water supply. The drift can result in PM_{10} emissions that are formed when the drift droplets evaporate and leave fine PM from crystallization of the dissolved solids suspended in the atmosphere.

As noted in the RLBC, high efficiency Drift Eliminators are the best means for reducing PM_{10} emissions by removing the optimal amount of droplets before they leave the tower.

Below is a listing of available and applicable control technologies for each criteria pollutant emitted from CTs and Cooling Towers.

Table 3: Technically viable control technologies

Pollutant	Viable Control Technology for combustion turbines
$PM/PM_{10}/PM_{2.5}$	Use of Pipeline quality natural gas fuel
SO_2	Use of Pipeline quality natural gas fuel, sulfur content limit
NO_x	DLNB, SCR, Water/Steam Injection, SCNR
CO	Catalytic Oxidation, Thermal Oxidation, Excess Air, Proper Design and Operation
H_2SO_4 mist	Use of Pipeline quality natural gas fuel
CO_{2e}	Use of Pipeline quality natural gas fuel and Enhanced energy efficiency

Table 3 (Continued)

Pollutant	Viable Control Technology for cooling towers
$PM/PM_{10}/PM_{2.5}$	Mist (Drift) Eliminator
SO_2	NA
NO_x	NA
CO	NA
H_2SO_4 mist	NA
CO_{2e}	NA

3. Rank control technologies by control effectiveness.

The viable control technologies are listed below along with their control efficiencies. This table mirrors the data in the RLBC and numerous other sources that were researched during this review.

Table 4: Control efficiencies

Combustion Turbines:

Pollutant	Control Technology	Maximum Control Efficiency
$PM/PM_{10}/PM_{2.5}$	Use of Pipeline quality natural gas fuel	55% (fuel oil base case)
SO_2	Use of Pipeline quality natural gas fuel	NA
NO_x	Low NO_x Burners and SCR Steam Injection Selective Non-Catalytic Reduction Water Injection	90% 75% 60% 40%
CO	Catalytic Oxidation Thermal Oxidation Excess Air Proper Design and Operation	90% 90% NA NA
H_2SO_4 mist	Use of Pipeline quality natural gas fuel	NA
CO_{2e}	Use of Pipeline quality natural gas fuel	70% (fuel oil base case)

Table 4 (Continued)

Cooling Towers:

Pollutant	Control Technology	Maximum Control Efficiency
$PM/PM_{10}/PM_{2.5}$	Drift Eliminators	99%
SO_2	NA	NA
NO_x	NA	NA
CO	NA	NA
H_2SO_4 mist	NA	NA
CO_{2e}	NA	NA

4. Evaluate economic, environmental, and energy impacts of the most effective controls.

Based on the application provided by the source the Division researched various controls effectiveness and the impacts listed here. Please see item 2. entitled "Eliminate technically infeasible options."

5. Select BACT

Table 5

For Combustion Turbines:

Pollutant	Emission Limit	Averaging Time (From Test Method)	Control Technology
PM PM_{10} $PM_{2.5}$	0.0048 lb/mmBTU 0.0088 lb/mmBTU 0.0088 lb/mmBTU	3 hour rolling average	Use of Pipeline quality natural gas fuel
SO_2	0.0027 lb/mmBTU	3 hour rolling average	Use of Pipeline quality natural gas fuel, sulfur content limit
NO_x	2 ppmvd @15% O_2 0.0073 lb/mmBTU	3 hour rolling average	Low NO_x Burners and Selective Catalytic Reduction
CO	2 ppmvd @15% O_2 0.0044 lb/mmBTU	3 hour rolling average	Carbon Monoxide Catalytic Oxidation
H_2SO_4 mist	0.00042 lb/mmBTU	3 hour rolling average	Use of Pipeline quality natural gas fuel
CO_{2e}	884 lbs/MWH on a 12 month rolling average	12 month rolling average	Use of Pipeline quality natural gas fuel and Enhanced energy efficiency

Table 5 (Continued)

For Cooling Tower:

Pollutant	Emission Limit	Control Technology
PM/PM_{10}	0.715 lb/hr	Drift Eliminators
$PM_{2.5}$	0.0026 lb/hr	Drift Eliminators

MODELING ANALYSIS:

Modeling Background

Pursuant to 401 KAR 51:017, Section 10, an application for a PSD permit shall contain an analysis of ambient air quality impacts. Total project emissions of CO, NO_2, SO_2, PM_{10}, and $PM_{2.5}$ for the proposed facility are estimated to exceed the Prevention of Significant Deterioration (PSD) significant emission rates. To comply with the requirements of 401 KAR 51:017, the source submitted an ambient air quality analysis.

In the ambient air impact analysis, the source performed dispersion modeling for CO, NO_2, SO_2, PM_{10}, and $PM_{2.5}$ to demonstrate that emissions of regulated pollutants from the proposed project will not adversely affect air quality levels in the Class II areas surrounding the facility. Using procedures consistent with Appendix W to 40 CFR 51, the modeling was completed using the EPA recommended model AERMOD (version 12060). Representative meteorological data was processed using AERMET (version 11059). Using the AERMAP terrain processor (version 11103), receptor elevations were assigned to a gridded set of receptors beginning at the facility boundary extending out to approximately 50 km, depending on the pollutant and averaging period.

Class II Modeling Analysis

The short-term and long-term emission rates of CO, NO_2, SO_2, PM_{10}, and $PM_{2.5}$ from the planned project were explicitly modeled. These emissions were modeled using input parameters as tabulated in Table 6-2 in the June 2014 Revised Joint Application and inventory parameters as tabulated in the June 2014 Revised Joint Application, Appendix E. The resulting modeled concentrations, based on submissions from the source, were compared to the significant impact levels (SILs) and significant monitoring concentrations (SMCs) as shown in Table 1 below. The results show that the modeled CO, SO_2, and PM_{10} impacts are below the SILs and are presumed insignificant; thus, no further modeling was completed. For all other pollutant and averaging periods, further cumulative modeling was performed to demonstrate compliance with the PSD national ambient air quality standard (NAAQS) as tabulated in Table 2 below.

TABLE 1
Modeled Pollutant Concentrations in Comparison with Class II SILs

Pollutant	Averaging Period	Maximum Modeled Concentration (μg/m³)	Form and Year[c]	SIL (μg/m³)	Significant Monitoring Concentration (μg/m³)	Does Impact Exceed Threshold ?
CO	1-hour	3.9243	H1H; 2009 Airport	2000	-	No
	8-hour	1.9004	H1H; 2008 Site	500	575	No
NO_2	1-hour	30.12	H1H; 2009 Startup Airport	7.5[a]	-	Yes
	Annual	.69236	H1H; 2007 Startup Site	1	14	No
SO_2	1-hour	2.3967	H1H; 2009 Airport	7.86 [a]	-	No
	3-hour	1.3537	H1H; 2010 Site	25	-	No
	24-hour	.6018	H1H; 2011 Site	5	13	No
	Annual	.0547	H1H; 2011 Site	1	-	No
PM_{10}	24-hour	2.1599	H1H; 2011 Site	5	10	No
	Annual	.3404	H1H; 2011 Airport	1	-	No
$PM_{2.5}$	24-hour	2.0140	H1H; 2011 Site	1.2[b]	-	Yes
	Annual	.1804	H1H; 2011 Site	0.3 [b]	-	No

[a] Interim SIL
[b] Based on 40 CFR 51:165(b) (2)
[c] H1H refers to the high first high concentration of all receptors modeled for that time period

TABLE 2
Cumulative Modeled Pollutant Concentrations in Comparison with Class II PSD Increments

Pollutant	Averaging Period	Cumulative Modeled Concentration ($\mu g/m^3$)	Form and Year[a]	Project Contribution to Cumulative Impact greater than PSD Increment? ($\mu g/m^3$)	PSD Increment ($\mu g/m^3$)	Does Impact Cause or Contribute Significantly to a Modeled Violation?
NO_2	1-hour	-	H2H	-	NA	-
$PM_{2.5}$	24-hour	135	H2H 2010 50% Load	No .01	9	No

[a] H2H refers to the high second high concentration of all receptors modeled for that time period.

TABLE 3
Cumulative Modeled Pollutant Concentrations in Comparison with Class II NAAQS

Pollutant	Averaging Period	Modeled Concentration	Background Concentration[a]	Cumulative Modeled Concentration Plus Background ($\mu g/m^3$)	Form and Year[b]	Project Contribution to Cumulative Impact greater than NAAQS ($\mu g/m^3$)	NAAQS ($\mu g/m^3$)	Does Impact Cause or Contribute Significantly to a Modeled Violation?
NO_2	1-hour	1320	34	1354	H8H 5 year average 2007-2011	No 0.0	188	No
$PM_{2.5}$	24-hour	51	24	75	H8H 5 year average 2007-2011	No .09	35	No

[a] Background Data Sources:
NO_2 monitoring data source: Owensboro, Kentucky monitor (21-059-0005): 1-hour: 2010-2012 data;
$PM_{2.5}$ monitoring data source Henderson, Kentucky monitor (21-101-0014): 24-hr: 2010-2012 data
[b] HXH refers to the high X high concentration of all receptors modeled for that time period, where X represents the ranking

Additional Impacts Analysis:

401 KAR 51:017, Section 13 requires that all PSD applicants conduct additional Air Quality Impact Analyses (AQIA) that assesses impacts on soils, vegetation, and visibility caused by the increase in emissions from the new source. A review of potential growth in the community associated with the new source must also be conducted.

IMPACT ON SOILS, VEGETATION, AND VISIBILITY

The National Ambient Air Quality Standards (NAAQS) are designed to protect the health and welfare of residents and the environment, including the effects on soils and vegetation. According to the June 2014 Application, the emissions resulting from this project do not exceed any NAAQS, PSD Increment Standard or EPA Screening Levels. Therefore, no adverse impact to soil or vegetation is expected.

The source submitted VISCREEN (version 88341) modeling to the Division, demonstrating the absence of visual impacts at Henderson Airport, Evansville Airport, Owensboro Airport, Audubon State Park, Ben Hawes State Park, Higgenson Henry Wildlife Management Area and Sloughs Wildlife Management Area. Therefore, the facility's operation is not expected to impact visibility in these areas.

GROWTH

As discussed in the June 2014 Application, an impact on air quality due to regional growth attributed to the proposed project is projected to be negligible.

OZONE IMPACTS

As discussed in the June 2014 application, Appendix H – CAMx report on Ozone, an adverse impact on ambient ozone concentrations due to the proposed project is not expected.

IMPACT ON CLASS I AREAS

Mammoth Cave National Park and Mingo National Wildlife Reserve, located approximately 114 km southeast located and approximately 250 km miles southwest respectively of the proposed source, are designated Class I areas.

Additionally, demonstrated compliance with the Class I SIL and Increment Levels, a Q/D analysis and receptor field impacts in the direction of each Class I areas was performed.

COMMENTS:

Some of the emissions factors and stack parameters from the natural gas fired CTs were provided by the applicant, (Table 2-1 in the application), and their consultants. The stack testing and CEM requirements in the permit should verify these estimates.

Other sources of emission factors:

HAPS emissions from combustion of natural gas in large combined cycle turbines are based on emission factors in AP-42- Table 3.1-3.

HAP Emissions from the duct burners are based on emission factors in AP-42-Table 1.4-3.

CO_{2e} (CO_2, N_2O, CH_4) emissions are based on emission factors given by the Green House Gas Tailoring Rule.

Particulate emissions from the cooling tower are based on paper by Joel Reisman and Gordon Frisbie (Greystone Environmental Consultants, Inc.) "Calculating Realistic PM_{10} Emissions from Cooling Towers, Abstract No. 216.

OPERATIONAL FLEXIBILITY:

NA