Prevention of Significant Air Quality Deterioration Review
Of the Duke Energy Murray, L.L.C.
Murray Energy Facility
To be located in Murray County, Georgia

PRELIMINARY DETERMINATION
SIP Permit Application No. 13365
July 2002

<u>Reviewing Authority</u>

Georgia Department of Natural Resources
Environmental Protection Division
Air Protection Branch

Ron Methier – Chief, Air Protection Branch

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SUMMARY

On May 16, 2000, Duke Energy Murray, L.L.C. (Duke) submitted an application for an air quality permit to construct and operate two combustion turbine combined-cycle blocks at a site to be called the Murray Energy Facility in Murray County, Georgia, near Dalton, Georgia. Duke submitted an updated permit application which was received by the EPD on August 17, 2000. The Murray Energy Facility will be operated as a base load plant, and the Murray Energy Facility was issued PSD Permit No. 4911-213-0034-P-01-0 on February 13, 2001.

Since the time of the original application, Duke has determined that the originally planned auxiliary boiler capacity is inadequate. Duke submitted an updated permit application for this site on October 16, 2001 and this application is assigned Application No. 13365. The EPD received additional information supporting the permit application on February 5, 2002, June 6, 2002, and June 14, 2002. Application No. 13365 is a request for the following revision to the original plant configuration: (1) Revise Condition 2.13 by raising the allowable annual hours of operation from 2,500 to 6,000 for auxiliary boiler AUXB; and (2) authorize the construction and operation of a second auxiliary boiler rated at approximately 31.4 MMBtu/hr fired on natural gas and operated no more than 6,000 hours per year.

Upon issuance of PSD Permit No. 4911-213-0034-P-01-0 on February 13, 2001, the Georgia Center for Law in the Public Interest (GCLPI) submitted an appeal to said permit on March 15, 2001. To more quickly resolve the appeal, Duke entered into a settlement agreement with GCLPI, which took effect on September 14, 2001. This agreements includes the following: (1) Revise Condition 2.10 by lowering the NOx BACT limit from 3.5 ppmvd at 15% oxygen to 3.0 ppmvd at 15% oxygen; (2) Revise Condition 2.11.a by lowering the CO BACT limit from 0.0467 pounds per million Btu heat input, lower heating value (LHV) basis to 12 ppmvd at 15% oxygen; (3) Revise Condition 2.11.c by lowering the VOC BACT limit from 0.010 pounds per million Btu heat input, as methane, LHV basis to 4.5 ppmvd at 15% oxygen; and (4) Revise Condition 2.11.b by lowering the PM BACT limit from 0.017 pounds per million Btu heat input, LHV basis to 25 pounds per hour. These revisions are being made on a voluntary basis by Duke Energy Murray and do not change EPD's BACT determination contained in Permit No. 4911-213-0034-P-01-0 issued February 13, 2001.

The location of the combustion facility in Murray County is classified as "attainment" for PM_{10}, NOx, CO, SO_2 and Ozone in accordance with Section 107 of the Clean Air Act, as amended August 1977.

The EPD review of the revised facility configuration submitted by Duke for the construction and operation of the Murray Energy Facility indicates that compliance with all applicable State and Federal air quality regulations will be achieved.

It has been determined through approved modeling techniques, that the estimated emissions will not cause or contribute to a violation of any ambient air standard or allowable PSD increment. It has further been determined that the proposal will not cause impairment of visibility or detrimental effects on soils or vegetation. Any air quality impacts produced by project-related growth should be inconsequential.

It is the Preliminary Determination of the EPD that the proposal provides for the application of best available control technology (BACT) for the control of NOx, CO, SO_2, VOC, PM, and PM_{10} from the auxiliary boilers as required by Federal PSD regulation 40 CFR 52.21(j).

The Preliminary Determination indicates that an Air Quality Permit Amendment should be issued to Duke Energy Murray, L.L.C. for authorizing the increase operational time for the existing auxiliary boiler; for the construction and operation of the second auxiliary boiler; and for revision to NOx, CO, VOC, and PM BACT emission limits for each combined turbine and duct burner stack. Various conditions will be made a part of the permit amendment to construct and operate in order to insure and confirm compliance with all applicable regulations. A copy of the draft permit amendment is provided in Appendix A.

1.0 INTRODUCTION

On May 16, 2000, Duke Energy Murray, L.L.C. (Duke) submitted an application for an air quality permit to construct and operate two combustion turbine combined-cycle blocks at a site to be called the Murray Energy Facility in Murray County, Georgia, near Dalton, Georgia. Duke submitted an updated permit application which was received by the EPD on August 17, 2000. The Murray Energy Facility will be operated as a base load plant, and the Murray Energy Facility was issued PSD Permit No. 4911-213-0034-P-01-0 on February 13, 2001.

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Portions of this site have commenced construction and experienced initial startup as illustrated in the following table:

Equipment	Date(s)
Emergency Diesel Generators GEN1 and GEN2	Initial Startup - January 8, 2002
Diesel Fire Pump FP1	Initial Startup - December 13, 2001
Duct Burners	Commencement of Construction – March 27, 2001

Equipment	Date(s)
Combustion Turbines	Commencement of Construction – March 27, 2001 Initial Startup – March 5, 2002 for CT1 Initial Startup – March 10, 2002 for CT2 Commercial Operation – March 30, 2002
Auxiliary Boiler (Source Code AUXB)	Commencement of Construction – July 2, 2001 Initial Startup – February 19, 2002

Duke has not yet conducted performance testing for the combined-cycle systems and the existing auxiliary boiler.

Duke's application and supporting data are included in Appendix B.

Table 1 of the Preliminary Determination for the original configuration at Duke's Murray County Plant (Application No. 12280) has been updated to account for the configuration changes and revised BACT emission limits for the combined-cycle units. Based on the information in updated Table 1, below, Duke's proposed new stationary source is still classified as a major source under PSD because potential emissions of at least one PSD pollutant exceeds 100 tpy [*it is one of the 28 named source categories in 40 CFR 52.21(b)(1)(i)(a)*].

Table 1. Emissions Summary of the Murray Energy Facility

Pollutant	Potential To Emit Original (TPY)	Potential to Emit Revised (TPY)	PSD Significant Emissions Level	Is BACT Required?
NOx	570	425.73	40	YES
CO	2,124	1016.05	100	YES
VOC	355	217.41	40	YES
SO_2	236	236	40	YES
PM	605	440.48	25	YES
PM_{10}	605	440.48	15	YES
Lead	~0	~0	0.60	NO
Sulfuric Acid Mist	~0	~0	7	NO
Beryllium	~0	~0	NA	NA
Mercury	~0	~0	NA	NA
Vinyl Chloride	~0	~0	NA	NA
1,3-Butadiene	0.014	0.014	NA	NA
Acetaldehyde	1.6	1.6	NA	NA
Acrolein	0.31	0.31	NA	NA
Benzene	0.52	0.52	NA	NA
Ethylbenzene	1.05	1.05	NA	NA
Formaldehyde	6.06	6.06	NA	NA
Hexane	1.03	1.03	NA	NA

Pollutant	Potential To Emit Original (TPY)	Potential to Emit Revised (TPY)	PSD Significant Emissions Level	Is BACT Required?
Naphthalene	0.041	0.041	NA	NA
Polycyclic Aromatic Hydrocarbons	0.37	0.37	NA	NA
Propylene Oxide	0.96	0.96	NA	NA
Toluene	6.10	6.10	NA	NA
Xylene (total)	2.19	2.19	NA	NA
Total HAPs	20.26	20.26	NA	NA

*Computation of criteria air pollutants is provided in Appendix B of this Preliminary Determination.

Through its new source review procedure, the EPD has evaluated the revised Duke proposal for compliance with State and Federal requirements. The findings of the EPD have been assembled in this Preliminary Determination.

This Preliminary Determination will only cover changes to the original Preliminary Determination for Application No. 12280 for Duke Energy Murray, LLC.

2.0 REVIEW OF APPLICABLE RULES AND REGULATIONS

Section 3.0 of the Preliminary Determination for Application No. 12280 (Duke Energy Murray, LLC) is updated as follows:

40 CFR 60, Subpart Dc - Standard of Performance for Small Industrial Commercial-Institutional Steam Generating Units

Applicability: NSPS Dc is an applicable requirement for the additional auxiliary boiler because it has a design heat input capacity of 100 MMBtu/hr or less, but greater than or equal to 10 MMBtu/hr and because it was constructed after June 9, 1989.

Emission Standard: NSPS Dc does not define any emission standard for this boiler because it is exclusively fired with natural gas.

Compliance Demonstration: The Permittee is subject to the reporting and record keeping requirement of 40 CFR 60.48c(g). This portion of NSPS Dc requires the maintenance of records specifying the amount of fuel combusted during each day. In this case, this requirement can be altered, by EPA, pursuant to authority in 40 CFR 60.13(i). EPA notes, "Since there are no applicable emission standards for natural gas combustion in Subpart Dc, the amount of gas burned each day has no bearing on the compliance status of the boiler."[1] In the case of natural gas combustion, EPA Region 4 has approved an alternative fuel usage record keeping frequency of monthly.

[1] See Alternative Fuel Usage Recordkeeping Frequency Proposed for Boiler at Shaw Industries, U.S. EPA Region IV, August 14, 1996.

3.0 CONTROL TECHNOLOGY REVIEW – AUXILIARY BOILER

A control technology review was conducted for nitrogen oxides (NOx), carbon monoxide (CO), volatile organic compounds (VOCs), sulfur dioxide (SO_2) and particulate matter (PM and PM_{10}).

Oxides of Nitrogen

Top-Down BACT Alternatives: In reviewing the BACT alternatives to control emissions of NOx, Duke considered post-combustion control technology (selective catalytic reduction, selective non-catalytic reduction, and catalytic absorption) and combustion modifications (flue gas recirculation and low NOx burners). NSPS Dc is an applicable requirement for the boilers; however, this NSPS imposes no NOx emission standards because the fuel-burning equipment will fire pipeline quality natural gas exclusively.

The individual NOx top-down BACT alternatives considered in this study are noted from the most to least stringent: catalytic absorption; selective catalytic and noncatalytic reduction, and combustion modifications. Note: This analysis will not consider the use of wet technology since this type of technology yields NOx reductions of approximately the same magnitude as that of dry controls.

Technical Feasibility Analysis: Catalytic absorption is a type of post-combustion control whereby the flue gas is exhausted over a catalyst system with an absorber coating to oxidize CO to CO_2 and NO to NO_2. The SCONOx^{TM} system, developed by Goal Line Environmental Technologies, is a proprietary precious metal oxidation catalyst system with an absorber coating. The EPD recognizes this technology as extremely promising; however, it is our position that catalytic absorption has not been sufficiently demonstrated over the broad range of boiler sizes to be considered a proven technology for the purpose of establishing its use as BACT in this case. However, the EPD will continue to monitor the application of SCONOx™ and its impact on future natural gas fired boiler BACT.

Selective Catalytic Reduction (SCR) selectively reduces NOx emissions by injecting ammonia into the exhaust gas upstream of a catalyst where the NOx reacts with the ammonia and oxygen to form nitrogen and water. The use of SCR is technically feasible.

Selective Non-Catalytic Reduction (SNCR) removes NOx through a mechanism similar to SCR. The difference between the two technologies is that the chemical reactions are not catalyzed. The use of SNCR is technically feasible.

Dry Low NOx burner technology includes low excess air (LEA) firing and a unique burner design. The use of dry low NOx burner technology is technically feasible.

Flue gas recirculation (FGR) entails recirculating a portion of the relatively cool exhaust gases back into the combustion zone in order to lower the flame temperature and reduce NOx formation. The use of FGR is technically feasible.

Ranking the Technically Feasible Alternatives: For this project, SCR is recognized as the top control option followed by SNCR and the use of dry low NOx burners in combination with flue gas recirculation.

NOx BACT Emission Standard Analysis:: The lowest permitted NOx emission rate for similar/identical boilers found by EPD are illustrated in the following table:

Facility	Permitted NOx Emission Limit
CA – Margaretis Textile Service/MTS, Inc. 4.2 MMBtu/hr Kewanee Model Fire Tube Boiler Permit Issued 3/16/00	2 ppmvd at 3% oxygen at applicant request using catalytic absorption by Goal Line Technologies. South Coast AQMD noted that this emission level is not recognized as achieved in practice.
CA – Coca Cola 31.5 MMBtu/hr Scotch Marine Fire Tube Boiler Permit Issued 11/23/99	7 ppmvd at 3% oxygen using low NOx burner and SCR.
CA – Bumble Bee Seafoods, Inc. 16.8 MMBtu/hr Superior Mohawk Model Fire Tube Boiler Permit Issued 3/10/00	12 pppmv at 3% oxygen using low NOx burner and flue gas recirculation.
CA – Bay Area Air Quality Management District	20 ppmvd at 3% oxygen using low NOx burners and FGR

The EPD also compared Duke's proposal with the US EPA AP-42 and Georgia Rule 391-3-1-.02(2)(lll) and this comparison is illustrated in the following table:

Reference	NOx Emission Limit
AP-42 for Uncontrolled Boilers less than 100 MMBtu/hr fired with Natural Gas	100 lb/MMscf (~3.08 lb/hr)
AP-42 for Boilers equipped with Low NOx Burners and rated less than 100 MMBtu/hr fired with Natural Gas	50 lb/MMscf (~1.54 lb/hr)
AP-42 for Boilers equipped with Low NOx Burners and FGR and rated less than 100 MMBtu/hr fired with Natural Gas	32 lb/MMscf (~0.98 lb/hr)
Georgia Rule 391-3-1-.02(2)(lll)	30 ppm at 3% oxygen

Energy Impacts: Duke did not specify any energy impacts associated with the technically feasible alternatives.

Environmental Impacts: SCR and SNCR requires the injection of ammonia at slightly above the stoichiometric rate which inevitably results in ammonia "slip" or emissions of unreacted ammonia. Collateral environmental concerns evaluated were the presence of ammonia emissions; the formation of fine particulates; and the safety hazards associated with the transport, handling, and storage of ammonia. The presence of unreacted ammonia in the boiler exhaust could possibly react with NOx, sulfate or oxygen species to form fine particles of ammonium nitrate and/or ammonium sulfate which would primarily exist as fine particulate emissions (PM2.5). PSD regulations do not provide a mechanism to analyze the impact of PM2.5 at this time.

The use of SCR and SNCR requires that the proposed plant configuration include ammonia storage and handling capabilities. Duke did not cite ammonia safety concerns as an issue that would mitigate the benefit of using SCR to control NOx emissions. This project would be subject to risk management plans under Section 112(r) of the 1990 Clean Air Act Amendments (40 CFR 68) if they store more than 10,000 pounds of anhydrous ammonia in one tank at any one time at the facility. The amount of ammonia that will be used by the project will depend on the load factor of the unit. Since both of these factors are based on future economic conditions, it is difficult to predict exactly how much ammonia will be used. This PSD preliminary determination asserts that Duke would achieve compliance with the Part 68 standard if this option was implemented as BACT.

Economic Impacts: Duke proposed a NOx BACT limit (baseline) for this option to be 1.11 lb/hr (i.e., 28.88 ppmvd at 3% oxygen).

Control Option	Hrs of Operation	Baseline Emissions Per Boiler (TPY/ppmv d)	Total Emissions After Controls (TPY/ppmvd)	Reduction (TPY)	Cost per Ton of NOx Removed
SCR	6000	3.33/28.88	0.67/5.8	2.66	$82,570
SNCR	6000	3.33/28.88	0.67/5.8	2.66	$78,358
DLN+FGR	6000	3.33/28.88	1.38/12.0	1.95	>$45,000
DLN+FGR	6000	3.33/28.88	2.22/20.0	1.11	$45,000
DLN+FGR	6000	3.33/28.88	3.33/28.88	Baseline	Baseline

DLN = Dry Low NOx burner; FGR = Flue Gas Recirculation

NOx BACT Selection: EPD rejects SCR and SNCR as BACT based on unreasonable costs associated with controlling very low NOx emissions. The EPD accepts the applicant's determination that NOx BACT for this project is the use of dry low NOx burners in combination with flue gas recirculation with an operational limit of 6,000 hours per year per boiler. EPD rejects NOx BACT limits lower than 28.88 ppmvd at 3% oxygen (using a fuel factor of 8710) based on unreasonable costs. The averaging time of these emission limitations are tied to or based on the run time(s) specified by the applicable reference test method(s) or procedures required for demonstrating compliance (i.e., Method 7E – 3 hour averaging period). The EPD believes that this determination is consistent with recent BACT determinations. The operation of each boiler is limited to 6000 hours of operation per twelve consecutive months.

<u>Carbon Monoxide and Volatile Organic Compounds</u>

Top-Down BACT Alternatives: In reviewing the BACT alternatives to control emissions of CO and VOC, Duke considered "Good Combustion Practice" (GCP) and catalytic oxidation for both CO and VOC emissions.

Technical Feasibility Analysis: The EPD considers GCP and catalytic oxidation as technically feasible for the boiler size in question.

CO and VOC BACT Emission Standard Analysis: Duke proposed a CO BACT level of 0.037 lb/MMBtu (HHV value) which is equivalent to 1.15 lb/hr and 50.17 ppmvd at 3% oxygen. The lowest permitted CO emission rate for similar/identical boilers found by EPD are illustrated in the following table:

Facility	Permitted CO Emission Limit
CA – Margaretis Textile Service/MTS, Inc. 4.2 MMBtu/hr Kewanee Model Fire Tube Boiler Permit Issued 3/16/00	2 ppmvd at 3% oxygen at applicant request using catalytic absorption by Goal Line Technologies. South Coast AQMD noted that this emission level is not recognized as achieved in practice.
CA – Bumble Bee Seafoods, Inc. 16.8 MMBtu/hr Superior Mohawk Model Fire Tube Boiler Permit Issued 3/10/00	50 pppmv at 3% oxygen
CA – Coca Cola 31.5 MMBtu/hr Scotch Marine Fire Tube Boiler Permit Issued 11/23/99	50 ppmvd at 3% oxygen
Bay Area Air Quality Management District	50 ppmvd at 3% oxygen using GCP
IN – Duke Energy Vigo, LLC	0.082 lb/MMBtu, HHV using GCP 3.38 lb/hr 111.18 ppmvd at 3% oxygen

Duke proposed a VOC BACT level of 0.0127 lb/MMBtu (HHV value) which is equivalent to 0.38 lb/hr and 30 ppmvd at 3% oxygen. The lowest permitted VOC emission rate for similar/identical boilers found by EPD are illustrated in the following table:

Facility	Permitted VOC Emission Limit
CA – La Paloma Generating Co., LLC	30 ppmv at 3% oxygen, no control
IN – Duke Energy Vigo, LLC	0.0054 lb/MMBtu, HHV using GCP 0.25 lb/hr 12.81 ppmvd at 3% oxygen

Energy Impacts: The impact on efficiency and capacity of the boiler when taking into account GCP and/or induced FGR should be minimal as long the Permittee selects the proper boiler to meet the overall system load requirements.

Environmental Impacts: There are no environmental impacts associated with the use of GCP in combination with flue gas recirculation.

Economic Impacts:

Control Option	Hrs of Operation	Baseline Emissions Per Boiler (TPY/ppmvd)	Total Emissions After Controls (TPY/ppmvd)	Reduction (TPY)	Cost per Ton of NOx Removed
Catalytic Oxidation	6000	1.14/30	0.48/13.0	0.66	$85,000
Good Combustion Practice	6000	1.14/30	1.14/30	Baseline	Baseline

CO and VOC BACT Selection: The EPD rejects catalytic oxidation based on unreasonable costs associated with controlling very low CO and VOC emissions. The EPD accepts the applicant's determination that CO and VOC BACT for this project is good combustion practice with an operational limit of 6,000 hours per year per boiler. The EPD accepts the applicant's proposal that CO BACT is 1.15 lb/hr (0.037 lb/MMBtu, 50 ppmvd at 3% oxygen) and that VOC BACT is 0.38 lb/hr (0.0127 lb/MMBtu, 30 ppmvd at 3% oxygen). The averaging time of these emission limitations are tied to or based on the run time(s) specified by the applicable reference test method(s) or procedures required for demonstrating compliance (i.e., in this case the averaging period is 3 hours for both CO and VOC).

Particulate Matter (PM/PM10) and Sulfur Dioxide

Top-Down BACT Alternatives: The BACT alternatives considered by Duke include the use of pipeline quality natural gas in combination with GCP and flue gas recirculation. This option is technically feasible.

BACT Selection: The applicant proposed the use of pipeline quality natural gas as BACT for PM/PM10 and sulfur dioxide. They proposed a PM BACT emission limit of 0.31 lb/hr (or 0.010 lb/MMBtu). The EPD has determined that Duke's proposal to use proper combustion design and the use of pipeline quality natural gas meets the requirements of BACT for PM/PM10 and sulfur dioxide. The EPD proposes a PM/PM10 BACT emission limit of 0.010 lb/MMBtu for natural gas combustion.

4.0 TESTING AND MONITORING REQUIREMENTS

Condition 4.4 requires a performance test for NOx and CO for only one boiler. Condition 5.3.d requires the Permittee to monitor the cumulative total hours of operation, during all periods of operation, for each boiler. Condition 8.4 requires the Permittee maintain the net operating hours for each boiler for every calendar month and the total operating hours for each twelve consecutive month period. Condition 8.16.b.vi defines an exceedance as any twelve consecutive month total hours of operation which exceeds 6,000 hours. Condition 8.17 requires the Permittee submit a quarterly report which includes the twelve consecutive month total hours of operation for each boiler for each month in the quarterly reporting period.

5.0 AMBIENT AIR QUALITY REVIEW

An air quality analysis is required of the ambient impacts associated with the construction and operation of the Murray Energy Facility. The main purpose of the air quality analysis is to demonstrate that emissions emitted from the proposed new major stationary source, in conjunction with other applicable emissions from existing sources (including secondary emissions from growth associated with the new project), will not cause or contribute to a violation of any applicable National Ambient Air Quality Standard (NAAQS) or PSD increment. in a Class II or Class I area. NAAQS exist for NO_2, CO, PM_{10}, SO_2, Ozone (O_3), and lead (P_b). PSD increments exist for SO_2, NO_2, and PM_{10}.

A separate air quality analysis is required for each of these pollutants to be emitted in an amount over the PSD significant threshold. For all applicable air pollutants whose emissions will exceed the PSD significant emission rate, as shown in Table 1, a source impact analysis is performed to determine whether the project alone will result in predicted impacts that will exceed the U.S. EPA significant impact levels (SILs) at any off-plant property areas. If any of the proposed project's impacts are above the SIL, then a more detailed air modeling analysis that includes background sources is performed.

Generally, the source impact analysis will involve (1) an assessment of existing air quality, which may include ambient monitoring data and air quality dispersion modeling results, and (2) predictions, using dispersion modeling, of ambient concentrations that will result from the proposed plant and future growth associated with the project.

PSD review requires that sources located within 100 kilometers of a Class I area be evaluated for possible impact on that area (i.e., Class I Analysis). Duke proposed to investigate the need for conducting a Class I Analysis for Class I areas within 200 km of the facility, based on the requested permit revisions, and these Class I areas are illustrated in the following table:

Class I Area	Approximate Distance from Proposed Site	Date of Notification of FLM
Cohutta Wilderness Area (CWA)	30 km	11/02/01
Joyce Kilmer/Slickrock Wilderness Area (JKSWA)	109 km	11/02/01
Great Smokies National Park	118 km	11/2/01

The Federal Land Managers (FLMs) were silent on the need for further analysis of impacts on the applicable Class I areas.

The EPD conducted a PSD modeling evaluation for the original plant configuration and documentation of this evaluation was included as Appendix C of the PSD Preliminary Determination for Application No. 12280 – Duke Energy Murray, LLC. A summary of the results of this evaluation is noted as follows:

*Air impact analysis was performed for CO, NOx, PM10, and SO_2.

* The predicted concentrations were below the de minimis levels for all four pollutants, which automatically exempts them from preconstruction monitoring.

* The predicted concentrations were below the Class II significant impact levels for all four pollutants. Thus, Class II increment and NAAQS modeling are not required.

* A PSD Class I increment analysis for PM10 and SO_2 in the Cohutta Class I area was conducted because the predicted concentrations were above the Class I significant impact levels for these pollutants. All results from the PSD Class I increment analysis for the Cohutta Wilderness area show the predicted concentrations below the PSD Class I increments for PM10 and SO_2.

With the permit revision:

* The short term NOx, CO, VOC, and PM/PM10 BACT from the combined turbine and duct burner stacks are reduced.

* There is an increase in the annual NOx emissions from the permitted boiler.

* There is an increase in emissions due to the existence of a second auxiliary boiler.

* Annual NOx, CO, SO_2, and PM10 emissions are less than or equal to the original configuration.

Duke presented a revised dispersion modeling analysis in Application No. 13404. Duke followed the appropriate air quality impact procedures found in the PSD regulation.

Notes on Dispersion Model Used in this Analysis: Dispersion models are the primary tools used to estimate the ambient concentrations that will result from the PSD applicant's proposed emissions in combination with emissions from existing sources. The estimated total concentrations must demonstrate compliance with the applicable NAAQS or PSD increments. The dispersion models are based upon the assumption that the dispersion of pollutants is primarily a function of: wind speed and direction; atmospheric stability conditions; and the effective point of discharge of the exhaust plume. To predict ambient air concentrations, the models simulate the plume exhausting from the stack, rising a certain distance in the atmosphere, leveling off, and continuing downwind over relatively flat terrain. The concentrations of pollutants are assumed to have a Gaussian distribution about the longitudinal centerline of the plume.

Both simple terrain screening and refined modeling were conducted using the U.S. EPA's Industrial Source Complex Short Term (ISCST3) model. The ISCST3 model combines the evaluated concentrations for a range of possible meteorological conditions for both simple terrain (below stack top) and complex terrain (above stack top).

ISCST3 is a Gaussian plume dispersion model which estimates hour-by-hour ground level concentrations of emissions from an elevated source. The model provides maximum 1-hour, 3-hour, 24-hour, and annual average concentrations for receptors located on a radial grid spaced at ten degree intervals around the source for various downwind distances, and also takes into account the effect of downwash caused by nearby buildings and structures.

Input Data – Meteorological Data: No change from the met data used in the original analysis (Application No. 12280) is proposed. The EPD used surface data from Chattanooga, Tennessee and upper air data from Greensboro, North Carolina for the 5-year period from 1984-1987 and 1989.

Input Data – Source Types: The combined-cycle stacks and boiler stacks were modeled as point sources. The emergency generators and firewater pump emissions were not included because of their non-routine nature.

Input Data – Source Data: The *Guidelines on Air Quality Models* [40 CFR 51, Appendix W] states that modeling should contain sufficient detail to determine the maximum ambient concentration of the pollutant under consideration, and that this will likely involve modeling several operational loads or production rates. For some types of sources, operating at a reduced load translates into reduced stack gas exit velocities leading to different and potentially higher impact characteristics.

Duke conducted a preliminary screening analysis to determine which operating load results in the highest impacts for each combustion fuel for the Duke Murray site. The *Load Modeling Analysis* for Duke Murray is found in Section 6.2.1 of Application No. 12280 (Duke Energy Murray, LLC). Table 5 (Modeled Source Parameters) of the updated PSD Application (No. 13404) replaces Table 6-5 of the original PSD Application (no. 12280).

The modeling of the CTs was performed using actual stack heights since the proposed stack heights do not exceed "good engineering practice" (GEP) requirements. Duke modeled one stack parameters and emissions configuration for each applicable criteria pollutant, in this case NOx, CO, SO_2, and PM10, corresponding to the maximum impact conditions.

Input Data – Building Downwash: Building downwash was considered as part of the revised modeling analysis because the boilers and combined combustion turbine and duct burner stack heights do not exceed "good engineering practice" (GEP) height.

Input Data – Receptor Locations: There is no revision to receptor locations used in original application number 12280 analysis. The receptor grid consisted of receptors at 100-meter intervals along the site boundary and a cartesian grid with a spacing of 100 meters to a downwind distance of approximately 1 km, a spacing of 500 meters from 1 to 5 km, and a spacing of 1 km from 5 to 10 km. A separate receptor grid was developed for the Cohutta Class I area. The proposed stack height for the combustion turbines is 160 feet. Impacts were calculated at all receptor grid receptors in the Significance Analysis to determine the significant impact area.

Input Data – Terrain Elevation: The stacks were modeled at a base elevation of approximately 698 feet.

Class II Air Dispersion Modeling Results: The air dispersion modeling results for the Murray Energy Facility are illustrated in the following table:

Pollutant	Averaging Period	Preconstruction Monitoring Evaluation (ug/m^3)	PSD Significant Impact Level (ug/m^3)	Original Projected Concentration (ug/m^3)	Revised Projected Concentration (ug/m^3)
CO	8 hour 1 hour	575 No 1 hour	500 2,000	74 178	22.79 58.04
NO_2	Annual	14	1	0.4	0.98
PM_{10}	Annual 24 hour	No annual 10	1 5	0.4 4.8	0.40 4.32
SO_2	Annual 24 hour 3 hour	No annual 13 No 3 hour	1 5 25	0.2 1.7 7.2	0.16 1.70 7.2

VOC	No significant air quality concentration for ozone monitoring has been established. Instead, applicants with a net emissions increase of 100 tons per year or more of VOCs subject to PSD would be required to perform an ambient impact analysis, including pre-application monitoring data	-	-

The need to submit continuous monitoring data prior to construction is based on evaluating the project's impacts relative to the PSD de minimis monitoring levels. For all applicable pollutants that have emission increases that will exceed the PSD significant emission rate, a de minimis impact analysis is performed to determine whether the project alone will result in predicted impacts that will exceed the EPA de minimis monitoring levels at any off-plant property areas. Current Georgia DNR policies stipulate that the highest annual average and highest short-term concentrations are to be compared to the applicable PSD de minimis monitoring levels.

As shown in table above, the maximum predicted NOx, CO, PM_{10}, and SO_2 impacts due to the revised site configuration are below the PSD de minimum monitoring levels. Therefore, pre-construction ambient monitoring does not have to be considered. The site will result in a net VOC emissions rate of greater than 100 tpy. Exemption from preconstruction monitoring requirements for ozone (VOC) are justified on the basis of the extensive existing monitoring network in Georgia for this air pollutant.

The table also shows that the proposed project will not cause ambient impacts of CO, NOx, PM_{10}, or SO_2 above the Class II PSD Significant Impact Level (SIL) for any applicable averaging period. Because the emissions increases from the proposed project result in ambient impacts less than the applicable PSD SIL for all averaging periods, neither PSD nor NAAQS analyses were conducted for CO, NOx, PM_{10}, or SO_2. This Preliminary Determination has considered the impact of the emissions from this facility on the ozone NAAQS. The Duke Energy Murray facility is located in an area that is in attainment of the one-hour ozone NAAQS. It is difficult, and somewhat impractical, to model the ozone contribution of individual sources since ozone is formed by complex reactions involving sunlight, NO_x and VOC emissions. Nonetheless the facility is not expected to have an adverse impact on ambient ozone levels. There are ongoing actions by both the EPD and the U.S. EPA that are expected to result in reductions in ozone in North Georgia (including Murray County). These include NOx and VOC reductions in and around Atlanta that are required by the Atlanta ozone SIP, the NOx SIP Call, national lower sulfur gasoline and diesel fuel, and lower emission standards on both off-road and on-road vehicles.

The EPD has determined that the revised maximum predicted impacts of these pollutants due to the proposed facility will consume 3.92 percent of the annual NO_2 PSD increment, 0.8 percent of the annual SO_2 increment, 1.86 percent of the 24-hour SO_2 increment, 1.40 percent of the 3-hour SO_2 increment, 2.35 percent of the annual PM_{10} increment, and 14.4 percent of the 24-hour PM_{10} increment. Thus the EPD has concluded that the facility will not adversely affect the air quality (i.e., exceed the allowable incremental increases in ambient concentrations of PM_{10}, SO_2, and NO_2.

Class I Air Dispersion Modeling Results: A significant impact area (SIA) analysis was performed for the Cohutta Wilderness Area since it is located within 100 km of the proposed site. The following table illustrates the results of this analysis:

Pollutant	Averaging Period	Class I Increment (ug/m^3)	Class I Significant Impact Level (ug/m^3)	Proposed Class I Significant Impact Level (ug/m^3)	Original Modeling Results (ug/m^3)	Revised Modeling Results (ug/m^3)
SO_2	Annual 24 hour 3 hour	2 5 25	1.0 1.0 1.0	0.1 0.2 1.0	0.04 0.29 1.31	0.04 0.34 1.24
NO_2	Annual	2.5	1.0	0.1	0.10	0.09
PM_{10}	Annual 24 hour	4 8	1.0 1.0	0.16 0.32	0.11 0.75	0.10 0.63

Predicted concentrations from the modeling study were above the proposed Class I Significant Impact Levels for PM_{10} and SO_2. Thus, a PSD analysis of all increment consuming sources was conducted for these pollutants in the CWA.

The PSD increment modeling analysis was performed using emissions from the proposed site along with other facilities within 50 km of the proposed site. Duke utilized the same inventory developed for the original PSD permit application (number 12280) in this modeling analysis. The results of Duke's analysis is presented in the following table and these results were taken from Table 10 in Duke's letter dated February 5, 2002. A copy of said letter can be found in Appendix B. The following table illustrates the highest predicted maximum concentration from all increment consuming sources at any time over the meteorological data considered, irrespective of whether or not Duke Energy had a significant impact at the same time. The November 2000 preliminary determination listed the maximum 24-hour and 3-hour SO_2 concentration for averaging periods only when Duke Energy was significant. Therefore, the highest predicted maximum concentration was not listed in the November 2000 preliminary determination

Pollutant	Averaging Period	Class I Increment (ug/m^3)	Revised -Max Increment Consumed (ug/m^3)
SO_2	Annual 24 hour 3 hour	2 5 25	1.6 8.48 33.94
PM_{10}	Annual 24 hour	4 8	0.25 1.05

Analysis of the data presented in the table above reveals that there are no Class I increment exceedances for all averaging periods of PM10 and for the annual averaging period of SO_2. However, there are Class I increment exceedances for both the three-hour and 24-hour averaging periods for SO_2.

For a source to be non-compliant with the Class I increment, the Class I increment must be exceeded at the same receptor, time, and averaging period as the source exceeds the Class I significant impact level. Duke conducted an analysis to compare the time and receptor location for each Class I increment exceedance to the time and receptor location for each Class I significant impact level exceedance. Based on this analysis, Duke determined that the Duke Energy Murray facility does not significantly contribute to the exceedances (i.e., contribution is less than the significance level at each specific time and located for all exceedances of the Class I Increment). Thus, the facility is in compliance with all Class I increment requirements.

Nonetheless, there are modeled violations of Class I increments that EPD must address. Since the time that Duke performed the modeling, EPD has required a number of sources in the area to reduce their SO_2 emissions. In addition, EPD has already begun the process of identifying the sources that contribute significantly to the violations and their relative contributions. EPD is continuing to work on this issue and expects to have a definitive plan for resolving the modeled PSD increment violations prior to final issuance of this permit.

Class I AQRV Analysis: As noted earlier, the PSD program establishes maximum allowable increases in air quality over baseline concentrations of certain pollutants for each class. These are referred to as increments. Class I increments cannot be exceeded by the proposed Duke plant unless Duke demonstrates to the satisfaction of, and receives approval from, the Class I Area Federal Land Manager (FLM), EPA, and EPD that air quality related values (AQRVs) of the applicable Class I area will not be adversely affected. It is important to note that Class I increment modeling is explicitly required by U.S. EPA while the AQRV analysis is referred to by the U.S. EPA but is not specifically required. Rather, for each project, the FLM reviews the project and determines which, if any, AQRVs are of interest. Once potential impacts on the site AQRVs are determined, the FLM notifies EPD that the AQRV analysis is satisfactory or that predicted impacts are excessive.

The applicable FLMs did not request the existing Class I Analysis (i.e., AQRV) be revisited. Thus, the results of the previous AQRV analyses still stand (i.e., Preliminary Determination for Duke Energy Murray, LLC, Application No. 12280

Georgia Air Toxics Guideline: There are no applicable NAAQS or specific Georgia ambient air standards for the non-criteria pollutants listed in Table 1. Impacts from each of the non-criteria air pollutants emitted by the facility were analyzed using the EPD Guidance for Ambient Impact Assessment of Toxic Air Pollutant Emissions (referred to as the Georgia Air Toxics Guideline; Version June 21, 1998) as part of the review of PSD Application No. 12280. The revised configuration does not increase emissions of non-criteria air pollutants. Thus, the results of the Georgia Air Toxics Guideline for Application No. 12280 still stand.

6.0 ADDITIONAL IMPACT ANALYSES

There is no revision needed for the impact analyses as documented in the Preliminary Determination for Application No. 12280 for the Duke Energy Murray, LLC project.

7.0 EXPLANATION OF DRAFT PERMIT AMENDMENT CONDITIONS

Draft Permit Amendment Number 4911-303-0040-P-01-1 includes the following revised conditions:

Condition 2.6 is revised to include two boilers rather than one.

Condition 2.10 is revised to specify the NOx BACT limit from said settlement agreement.

Condition 2.11.a is revised to specify the CO BACT limit from said settlement agreement.

Condition 2.11.b is revised to specify the PM BACT limit from said settlement agreement.

Condition 2.11.c is revised to specify the VOC BACT limit from said settlement agreement.

Condition 2.11.d is included again; however, the opacity limit is not revised.

Condition 2.12 is revised to include two boilers rather than one. The NOx BACT limit, specified in Condition 2.12.a is revised from 0.035 lb/MMBtu to 28.88 ppmvd at 3% oxygen. Condition Nos. 2.12.b through 2.12.e are included; however, these conditions are not revised.

Condition 4.1 is updated.

Condition 4.4 is updated.

Condition Nos. 5.3.a, 5.3.d, 8.3, 8.4.a, 8.4.b, 8.16.b.vi, and 8.17.b are updated to include two boilers rather than one boiler.

APPENDIX A

Draft PSD Permit Amendment for Duke Energy Murray, LLC

APPENDIX B

Duke Energy Murray, LLC PSD Permit Application and Supporting Data

Contents include:

1. Derivation of Criteria air pollutant emissions

2. Addendum to Original PSD permit application (no. 12280 dated May 15, 2000) assigned Application No. 13365 dated October 16, 2001 and updated February 5, 2002, June 6, 2002, and June 14, 2002.

DERIVATION OF CRITERIA EMISSION RATES

Combustion Turbine/Duct Burner

Potential to Emit:

Assume a heat input of 2121 MMBtu/hr is taken from Application No. 12280 at 88.3 deg F and baseload with duct firing.

NOx = (3.0 ppmvd at 15% oxygen)(2.59 x 10^{-9})(46)(8710)[20.9/(20.9-15)]
NOx = 0.01103 lb/MMBtu
NOx = (0.01103 lb/MMBtu)*(2121 MMBtu/hr)*(8760 hrs/yr)*(1 ton/2000 lbs)*(4 stacks)
NOx = 409.87 tpy

CO = (12.0 ppmvd at 15% oxygen)(2.59 x 10^{-9})(28)(8710)[20.9/(20.9-15)]
CO = 0.02685 lb/MMBtu
CO = (0.01103 lb/MMBtu)*(2121 MMBtu/hr)*(8760 hrs/yr)*(1 ton/2000 lbs)*(4 stacks)
CO = 997.75 tpy

VOC = (4.5 ppmvd at 15% oxygen)(2.59 x 10^{-9})(16)(8710)[20.9/(20.9-15)]
VOC= 0.00575 lb/MMBtu
VOC = (0.00575 lb/MMBtu)*(2121 MMBtu/hr)*(8760 hrs/yr)*(1 ton/2000 lbs)*(4 stacks)
VOC = 213.80 tpy

PM = (25 lb/hr)*(8760 hrs/yr)*(1 ton/2000 lbs)*(4 stacks)
PM = 438 tpy

Auxiliary Boiler

Potential to Emit = (lb/hr)*(2 stacks)*(6,000 hrs/yr)*(1 ton/2000 lbs)

The following table illustrates the range of emissions expected from the 31.4 MMBtu/hr natural gas fired boiler. EPD has included AP-42 data, low NOx burner, for comparison.

Pollutant	Emission Rate (lb/hr)	Source	Potential to Emit (TPY)
NOx	1.110	Table 2	6.66
CO	1.15	Table 2	6.90
VOC, as methane	0.38	June 14, 2002 e-mail	2.28
SO2	0.031	Table 2	0.186
PM/PM10	0.314	Table 2	1.88

In this case, a NOx emission rate of 1.11 lb/hr corresponds to 0.035 lb/MMBtu. A NOx emission rate of 0.035 lb/MMBtu corresponds to:

NOx= 0.035 lb/MMBtu = (C ppmvd at 3% oxygen)(2.59×10^{-9})(46)(8710)[20.9/(20.9-3)]

Solving for C yields,

NOx = 28.88 ppmvd at 3% oxygen

A VOC emission rate of 30 ppmvd at 3% oxygen corresponds to:

VOC (lb/MMBtu) = (30 ppmvd at 3% oxygen)(2.59×10^{-9})(16)(8710)[20.9/(20.9-3)]

VOC (lb/MMBtu) = 0.0127 lb/MMBtu

Emergency Diesel Generator and Diesel Firewater Pump

Potential to Emit = (lb /hr)*(2 generator)*(500 hrs/yr)*(1 ton/2000 lbs) + (lb/hr)*(2 pumps)*(500 hrs/yr)*(1 ton/2000 lb)

The following table illustrates the range of emissions expected from the diesel fired units. EPD has included AP-42 data for comparison.

Pollutant	Emission Rate (lb/hr)	Source	Potential to Emit (TPY)	Potential to Emit Used in Analysis (TPY)
Emergency Generator				
NOx	12.23 - 19.31	Appendix C Table 3-1 AP-42	6.114 6.2 9.65	6.2
CO	15.064 - 4.425	Appendix C Table 3-1 AP-42	7.532 7.6 2.21	7.6
HC	1.772 -	Appendix C Table 3-1	0.886 0.80	0.886
SO2	0.32 - 0.325	Appendix C Table 3-1 AP-42	0.0064 0.16 0.1625	0.16
PM/PM10	0.709 - 0.563	Appendix C Table 3-1 AP-42	0.031 0.40 0.281	0.40
Firewater Pumps				
NOx	6.08	Appendix C	2.31	

Pollutant	Emission Rate (lb/hr)	Source	Potential to Emit (TPY)	Potential to Emit Used in Analysis (TPY)
	- 4.40	Table 3-1 AP-42	3.0 2.2	3.0
CO	7.48 - 175.6	Appendix C Table 3-1 AP-42	3.74 3.8 87.80	3.8
VOC	0.88	Appendix C Table 3-1	0.44 0.40	0.44
SO2	0.16 - 0.236	Appendix C Table 3-1 AP-42	0.0016 0.08 0.118	0.08
PM/PM10	0.35 - 0.288	Appendix C Table 3-1 AP-42	0.00765 0.2 0.144	0.2

Total Potential to Emit for Criteria Pollutants

Pollutant	Equipment	Potential to Emit (TPY)
NOx	CT/DBs Boilers Generator Pumps Total	409.87 6.66 6.2 3.0 425.73
CO	CT/DBs Boilers Generator Pumps Total	997.75 6.90 7.6 3.8 1016.05
SO2	CT/DBs Boilers Generator Pumps Total	236.52 0.186 0.16 0.08 236.95
PM/PM10	CT/DBs Boilers Generator Pumps	438.0 1.88 0.40 0.20

	Total	440.48
VOC as methane	CT/DBs Boilers Generator Pumps Total	213.80 2.28 0.886 0.44 217.41