

**Prevention of Significant Air Quality Deterioration Review
Of the Duke Energy Sandersville, L.L.C.
Sandersville Generating Station
To be located in Washington County, Georgia**

**FINAL DETERMINATION
SIP Permit Application No. 12594
October 2001**

**State of Georgia
Department of Natural Resources
Environmental Protection Division
Air Protection Branch**

Ron Methier – Chief, Air Protection Branch

Stationary Source Permitting Program

**James Johnston, P.E.
James Capp
Susan Jenkins**

Planning & Support Program

**Dale Kemmerick
Richard Monteith**

TABLE OF CONTENTS

Background..... 1
Review of U.S. EPA Region IV Comments 1
Review of Duke’s Comments 2
Review of Georgia Center for Law in the Public Interest Comments 8
Additional Changes 22
Appendix A - Final PSD Permit
Appendix B - Comments on Draft Permit
Appendix C - Additional Correspondence

Background

On October 19, 2000, Duke Energy Sandersville, L.L.C. (Duke) submitted to the Environmental Protection Division (the Division) an application for an air quality permit to construct and operate a simple cycle combustion turbine facility in Warthen, Washington County, Georgia.

On July 27, 2001, the Division issued a Preliminary Determination stating that the construction and operation of the facility should be approved. The Preliminary Determination contained a draft Air Quality Permit for the construction and operation of the facility.

The Division requested that Duke place a public notice in a newspaper of general circulation in the area of the proposed facility notifying the public of the proposed construction and providing the opportunity for written public comment and public hearing. Such public notice was placed in *The Sandersville Progress* (legal organ for Washington County) on August 8, 2001 and in *The Sparta Ishmaelite* (legal organ for Hancock County) on August 9, 2001. The public comment period expired September 8, 2001 (weekend) and comments were received through September 10, 2001 (Monday).

During the comment period, comments were received from Duke, the U.S. EPA, and from the Georgia Center for Law in the Public Interest (GCLPI) on behalf of the Sierra Club and the Georgia Public Interest Research Group (GA PIRG). On September 10, 2001, the GCLPI, on behalf of the Sierra Club and the GA PIRG, requested in writing that the Division hold a public hearing on this draft Permit. A public hearing was held on Tuesday October 23, 2001 in Sandersville, Georgia. Oral comments were received from the GCLPI and various citizens during the public meeting/public hearing. Various citizens informed the Division of their support for the project. The GCLPI voiced their concern about the following items: (1) the ambient air quality impact analysis; and (2) the Division's BACT determinations.

The requested permit changes are described below along with the Division's written responses. The discussion will not elaborate on typographical or grammatical revisions made to the final permit. The permit has been changed based on the comments.

A copy of the final permit is provided in Appendix A. A copy of comments received during the public comment period is provided in Appendix B. A copy of additional correspondence received is provided in Appendix C.

Review of U.S. EPA Region IV Comments

1. Note A – Facility Description

Comment: EPA suggests adding that inlet air fogging is part of each simple cycle combustion turbine.

Response: The Division has incorporated this revision.

2. PM BACT limits

Comment: EPA requests that a notation be made in the PSD Final Determination and/or final permit that the PM emissions limits include both filterable and condensable particulate matter.

Response: EPA is correct in stating that the PM BACT limits include both filterable and condensable particulate matter. The permit requires that Method 5T be used to determine the particulate matter emission rate which is the appropriate method for the determination of both forms of particulate matter.

3. Compliance Averaging periods

Comment: The compliance averaging periods associated with emission limits for NO_x and CO are somewhat difficult to determine from the terms of the draft permit. We assume that the compliance averaging periods are equivalent to the measurement periods specified by the test methods listed in Condition 4.1 of the draft permit. If this is not the case, please advise us.

Response: That is the case and EPA is correct.

4. BACT Cost Analyses

Comment: A)EPA notes that in Duke's selective catalytic reduction and catalytic oxidation cost evaluations, the applicant appears to have double-counted the catalyst cost. B)Duke determined that the use of either SCR or catalytic oxidation would result in a power loss of 163 kW associated with the pressure drop. Duke used an energy penalty cost of \$0.065/kw-hr which is most likely equivalent to what Duke would charge for the power. EPA voiced concern that the value of the energy penalty unit cost should be equivalent to the cost associated with generating 163 kW and not based on how much revenue they would obtain from selling 163 kW.

Response: With regard to the applicant's SCR cost analysis found in Tables 5-3, 5-4, and 5-5 of the permit application: The Division adjusted the values in Table 5-4 to remove the double counting of the catalyst cost and to set the energy penalty unit cost at \$0.04/kW-hr. This results in a cost effectiveness of approximately \$23,000/ton of NO_x removed. With regard to the applicant's catalytic oxidation cost analysis found in updated Tables A-1 and A-2 (found in Appendix B of Preliminary Determination – Letter to the Division from Duke dated May 16, 2001): The Division believes that the applicant did not double count the cost of the catalyst. The Division adjusted the energy penalty unit cost to be \$0.04/kW-hr. This adjustment results in a cost effectiveness of approximately \$10,400/ton of CO removed. These revised calculations did not result in any change to the BACT determinations.

Review of Duke's Comments

5. Permit Cover Page

Comment: Duke has noted several items that they request be revised for clarity purposes.

Response: The Division agrees to all changes but one. Duke requested that the date of the application be revised from October 13, 2000 to October 18, 2000. The Division does not agree to this change because page 1 of the SIP permit application is dated October 13, 2000 and this date is used in the cover page of the permit.

6. Note A

Comment: Duke has noted several items that they request be revised for clarity purposes.

Response: The Division agrees to these changes in part. The Division has renamed Note A as Note B and the fuel oil is referenced as low sulfur fuel oil.

7. Draft Condition 2.2

Comment: Duke requests that this condition be removed in its entirety because neither federal nor state regulations mandate a condition of this nature. If the Division is unwilling to remove this condition, Duke requests that the date be revised to December 30, 2003, for completion of all aspects of the project with regards to operation of the facility on natural gas. Additionally, Duke proposes to use low sulfur No. 2 fuel oil as a backup fuel for the combustion turbines; the necessity of this backup

fuel will be determined some time after Duke has gathered actual operation information from this facility. Thus, Duke requests that the condition be amended to state that construction of the four large fuel oil tanks must be completed within five years of permit issuance.

Response: The Division is unwilling to remove this condition; however, the Division agrees to revise the condition as follows: (1) Construction of turbines shall be completed by December 30, 2003; (2) Construction of fuel oil storage tanks shall be completed by October 1, 2005.

8. **Draft Condition 2.3**

Comment: Condition 2.3 refers to low sulfur diesel fuel oil and Duke requests that the condition instead reference low sulfur No. 2 fuel oil.

Response: The Division has determined that identifying the fuel oil as “*low sulfur diesel fuel oil*” or as “*low sulfur No. 2 fuel oil*” is inconsistent with the terminology used in the ASTM standards and potentially confusing when certification of fuel sulfur is accomplished using supplier certifications. ASTM D396 (Standard Specifications for Fuel Oils) identifies fuel oil grades as No. 1, No. 2, etc. ASTM D975 (Standard Specification for Diesel Fuel Oils) identifies diesel fuel oil grades as Low Sulfur No. 1-D, Low Sulfur No. 2-D, No. 1-D, No. 2-D, and No. 4-D.

The limit on the fuel oil sulfur content in Condition 2.4 is the same as the maximum sulfur for Low Sulfur No. 1-D diesel fuel oil and Low Sulfur No. 2-D diesel fuel oil. Additionally, Condition 5.6 requires that the facility obtain from the supplier an analysis of the sulfur content.

It may be possible for the facility to locate a fuel supplier that is willing to conduct an analysis of the fuel oil for sulfur content and provide acceptable documentation of the analysis; however, the more likely scenario is that a supplier would deliver diesel fuel and provide a statement obtained from his/her vendor that the fuel is low sulfur diesel fuel that meets the specifications of ASTM D975.

Thus, Condition 2.3 will reference “*very low sulfur fuel oil*” and Condition 2.4 will be revised to provide a clearer definition of what is meant by “*very low sulfur fuel oil*”.

9. **Draft Condition 2.4**

Comment: Duke requested that Condition 2.4 be combined with Condition 2.3.

Response: This condition is not revised based on this comment.

10. **Draft Condition 2.5**

Comment: Duke requests that no individual turbine limits on heat input be issued but rather that the heat input be limited on a facility basis. They note that they are aware of the position that EPA Region IV has taken where the BACT analysis must be based on the maximum amount that any one of the multiple permitted units could run. Duke proposes to limit the total facility heat input to the equivalent of 20,000 turbine-hours, while limiting the maximum heat input of any single turbine to the equivalent of 4,000 hours. Duke notes that this equates to an annual heat input limit for the total facility of 2.088×10^{13} Btu/hr, LHV, and 4.12×10^{12} Btu/hr, LHV.

Response: Allowing a facility-wide operational limit, as requested by Duke, will allow one turbine to potentially operation 8760 hours per year. The Division maintains that an hours of operation or heat input limit must be specified per turbine unless the BACT analysis is performed at 8,760 hours per year per turbine. The Division has decided to replace Condition 2.5 with an operational limit of 2500

hours per year per turbine in order to avoid possible conflict concerning the appropriate fuel heating value.

11. **Draft Condition 2.6**

Comment: Duke voiced concern with several aspects of this condition. First, they request that the word “diesel” be replaced with “No. 2.” Secondly, the request that the unit for the fuel usage limit be revised from “Btu” to “MMBtu.” Lastly, they request that the heat input be revised from 140,000 Btu per gallon to 122,000 Btu per gallon, LHV.

Response: The Division has decided to replace Condition 2.6 with an operational limit of 500 hours per year per turbine in order to avoid possible conflict concerning the fuel heating value. The Division has removed the word “diesel.”

12. **Draft Condition Nos. 2.8a and 8.17.b.i**

Comment: Based on analysis of NO_x emissions from another similar Duke Energy peaking facility, Duke anticipates potential violations of the NO_x emission limit of 10 ppmvd at 15% oxygen on a 3-hour rolling average. With this in mind, the applicant requests the emission limit be relaxed to 10 ppmvd at 15% oxygen on a 24-hour rolling average.

Response: The Division maintains that the averaging period, in this case, should be based on the reference test method which is a 3 hour average. The applicant has failed to substantiate their claim that the operation of the proposed turbines will not comply with the proposed NO_x BACT limit at all operating conditions. The Division does not believe that the applicant’s claim justifies a relaxation of the proposed BACT NO_x limit. These conditions are not revised based on this comment.

13. **Draft Condition Nos. 2.8b and 8.17.b.iii**

Comment: Duke requests that the CO BACT limit be raised from 0.0592 lb/MMBtu to 0.0608 lb/MMBtu. Duke notes that the proposed CO BACT limit is taken from data supplied in the original permit application at 100% load and –6 deg F. They note that the maximum CO emission rate in lb/MMBtu occurs at 100% load and 60 deg F. Lastly, Duke requests that the averaging period be increased from 3 hours to 24 hours because of potential violations (i.e., a relaxation of the proposed CO BACT limit).

Response: Duke is correct in stating that the maximum CO emission rate **in lb/MMBtu** occurs at 100% load and at 64.6 deg F. The Division proposed a CO BACT limit based on the maximum **lb/hr** value which occurs at 100% load and –6 deg F. Incorporating Duke’s request would require that a new lb/hr CO emission rate be analyzed in the CO BACT analysis. In addition, the applicant has failed to submit information that shows that the operation of the proposed turbines will not comply with the proposed CO BACT limit at all operating conditions. These conditions are not revised based on this comment.

14. **Draft Condition 2.8c**

Comment: Duke requests that the PM BACT limit be raised from 0.01067 lb/MMBtu to 0.0198 lb/MMBtu. Duke notes that the proposed PM BACT limit is taken from data supplied in the original permit application at 100% load and –6 deg F. They note that the maximum PM emission rate occurs at 100% load and 108 deg F.

Response: The Division proposed a PM BACT limit based on the maximum **lb/hr** value which occurs at 100% load and –6 deg F. The applicant has failed to submit information that shows that the

he operation of the proposed turbines will not comply with the proposed PM BACT limit at all operating conditions. These conditions are not revised based on this comment.

15. **Draft Condition 2.9**

Comment: Duke requests that the word “diesel” be replaced with the word “No. 2.”

Response: Refer to comment #8.

16. **Draft Condition Nos. 2.9a and 8.17.b.ii**

Comment: Duke requests that the averaging period for the NO_x BACT limit be raised from 3 hours to 24 hours because of potential violations.

Response: The Division maintains that the averaging period, in this case, should be based on the reference test method which is a 3 hour average. The applicant has failed to substantiate their claim that the operation of the proposed turbines will not comply with the proposed NO_x BACT limit at all operating conditions. The Division does not believe that the applicant’s claim justifies a relaxation of the proposed BACT NO_x limit. These conditions are not revised based on this comment.

17. **Draft Condition Nos. 2.9b and 8.17.b.iv**

Comment: Duke requests that the CO BACT limit be raised from 0.0445 lb/MMBtu to 0.0471 lb/MMBtu. Duke notes that the proposed CO BACT limit is taken from data supplied in the original permit application at 100% load and –6 deg F. They note that the maximum CO emission rate occurs at 100% load and 108 deg F. Lastly, Duke requests that the averaging period be increased from 3 hours to 24 hours because of potential violations.

Response: The Division proposed a CO BACT limit based on the maximum **lb/hr** value which occurs at 100% load and –6 deg F. Incorporating Duke’s request would require that a new lb/hr CO emission rate be analyzed in the CO BACT analysis. In addition, the applicant has failed to submit information that shows that the operation of the proposed turbines will not comply with the proposed CO BACT limit at all operating conditions. These conditions are not revised based on this comment.

18. **Draft Condition 2.9c**

Comment: Duke requests that the PM BACT emissions limit be raised from 0.0127 lb/MMBtu (equivalent to 14 lb/hr) to 0.0391 lb/MMBtu (26 lb/hr) based, in part, on revised PM emission estimates from General Electric (the turbine vendor). Duke notes that the proposed PM BACT limit is taken from data supplied in the original permit application at 100% load and –6 deg F. They note that the maximum PM emission rate occurs at 100% load and 108 deg F.

Response: The Division proposed a PM BACT limit based on the maximum **lb/hr** value which occurs at 100% load and –6 deg F. The Division has reviewed the PM emissions data for fuel oil combustion submitted in Duke’s comments. The applicant has not provided the Division with actual PM test data while burning fuel oil which could shed light on the actual magnitude of the margin of compliance built into this updated vendor PM emission rate. The Division is not convinced, based on Duke’s comments, that the proposed emission rate cannot be met, under all operating conditions, during fuel oil combustion. This condition is not revised based on this comment.

19. Draft Condition 2.10

Comment: Duke requests that the word “each unit” be replaced with “the unit” since the facility has only one emergency firewater pump.

Response: The Division agrees to this change.

20. Draft Condition 2.11

Comment: Duke requests that the phrase “and T8” be revised to read as “or T8.”

Response: The Division agrees to this change.

21. Draft Condition Nos. 2.12 and 8.17.b.x

Comment: Duke requests that the phrase “and T8” be revised to read as “or T8.” In addition, Duke requests that the annual CO emission limit per turbine be based on 2500 hours of natural gas combustion instead of 2000 hours on natural gas and 500 hours on fuel oil. This would result in an increase in the annual CO emission limit.

Response: The Division has revised the phrase as requested. The annual CO emission limit per turbine is computed as follows: $(61 \text{ lb/hr-turbine}) \times (2500 \text{ hrs/yr}) \times (1 \text{ ton}/2000 \text{ lb}) = 76.25 \text{ tpy}$. The Division will increase the annual CO emission rate from 73 tpy to 76.25 tpy.

22. Draft Condition 4.2

Comment: Duke requests that the condition be split into two portions, one for each fuel. Duke does not anticipate equipping the turbines with fuel oil combustion capabilities during initial construction. Thus, they request that the fuel oil testing requirements be triggered only after installation of fuel oil firing capabilities.

Response: Condition 4.2 has been revised.

23. Draft Condition 4.2a

Comment: Duke requests that the initial testing for NO_x be limited to two of the eight combustion turbines, at peak load only. For the remaining six combustion turbines, Duke requests authorization to use Method 7E to determine the NO_x concentration at peak load only rather than Method 20.

Response: The Division maintains that the testing required by Condition 4.2.a is via Method 7E (i.e., to show compliance with Condition 2.8a.) The Division agrees that if the testing were only for NSPS GG purposes, Duke could test the NO_x emission rate from a subset of the eight combustion turbines. This is not the case for the permit in question. The Division maintains that testing of the NO_x emissions is required for each turbine since they are subject to PSD.

24. Draft Condition 4.2g

Comment: Duke requests that the phrase “base load” be replaced with “100% load.”

Response: The Division agrees to this revision.

25. Condition 5.2

Comment: Duke requests that the NO_x emission rates recorded should be converted to lb/MMBtu on a LHV basis.

Response: The Division agrees to this change.

26. Draft Condition 5.4

Comment: Duke requests that this condition allow for the option of either supplier certification or testing by Duke Energy.

Response: The Division agrees to this change.

27. Draft Condition 5.5

Comment: Duke requests that this condition be included with Condition 5.4.

Response: The Division is not inclined to make this change.

28. Draft Condition 5.6

Comment: Duke requests that the word “diesel” be replaced with “No. 2.”

Response: Refer to comment #8. Also, Draft Condition 8.10 has been combined with this condition.

29. Draft Condition 5.7

Comment: Duke requests removal of this condition since the GE machines proposed for this facility internally correct the emissions to ISO conditions. Thus, additional recording of met data is an unnecessary and undue burden. Should the Division not remove this condition, Duke requests clarification as to whether the National Weather Service data must be kept onsite or whether it can be obtained on an as needed basis.

Response: Condition 5.7 requires that the Permittee measure and record various parameters which are used to convert the measured NO_x concentration to ISO conditions. The Permittee’s comment illustrates that they will be able to monitor the appropriate parameters. The Division is not inclined to remove the record keeping requirement of this condition. The permit is not modified as requested.

30. Draft Condition 8.4

Comment: Duke requests that this condition reference the heat input on a LHV basis, a fuel oil heating value of 122,000 Btu/gal, LHV, and a natural gas heating value of 918 Btu/scf, LHV.

Response: As noted in the Division’s response to Condition Nos. 2.5 and 2.6, the operational limit on the turbines is no longer based on the fuel usage. The operational limits are now based on hours of operation. Thus, this condition is revised to require record keeping of the hours of operation.

31. Draft Condition 8.10

Comment: Duke requests that (1) the word “diesel” be replaced with “No. 2”; (2) clarify that multiple contemporaneous truck deliveries constitutes one shipment; and (3) add the noted legal citation to this condition.

Response: Refer to comment #8 for (1). The changes requested in (2) have been made in Condition 5.6. The change requested in comment 3 has not been incorporated at this time. Note: This condition has been combined with Draft Condition 5.6.

32. Draft Condition 8.15

Comment: Duke voiced concern about the need to submit daily CEMS drift tests in the quarterly reports and asks that this portion of the condition be stricken. Instead, Duke requests that the data be available for inspection onsite.

Response: The Division has revised this condition based on this comment.

[Review of Georgia Center for Law in the Public Interest Comments](#)

33. **Air Quality Impacts - Ozone**

Comment: The Clean Air Act requires that no major emitting facility be constructed in an area designated as attainment unless the owner or operator of such facility demonstrates that emissions from operation of such facility will not cause, or contribute to air pollution in excess of national ambient air quality standards (NAAQSs) in any air quality control region. 42 U.S.C. § 7475(a)(3)(B). Washington County is currently designated attainment for ozone so this provision applies. As Duke has failed to comply with this requirement, the Division may not issue this permit.

Duke has not demonstrated that it will not cause or contribute to NAAQS standard exceedances because it cannot make such a demonstration. The facility is proposed for Warthen, Georgia, which is approximately 50 kilometers from both the Macon region and the Augusta region, as the Division defines those regions for ozone monitoring. Already this year, the Macon region exceeded the one-hour ozone NAAQS one time and the eight-hour ozone NAAQS 6 times. In 2000, the Macon region exceeded the one-hour ozone NAAQS 3 times and the eight-hour ozone NAAQS 17 times. Already this year, the Augusta region has exceeded the one eight-hour ozone NAAQS three times. In 2000, the Augusta region exceeded the eight-hour ozone NAAQS six times and the one-hour NAAQS once. So far this year, the Augusta region has exceeded the eight-hour ozone NAAQS three times. Last year the Augusta region exceeded the one-hour ozone NAAQS one time and the eight-hour ozone NAAQS six times. In 1999, the Augusta region exceeded the eight-hour ozone standard nine times. While the Facility's 793 tons per year (tpy) of NO_x as well as its VOC may not be the sole source of future ozone exceedances in the Macon and Augusta regions, they certainly will contribute to these exceedances. Therefore, the Division must deny this permit.

Response: Washington County, where Duke's facility would be located, is currently in compliance with the 1-hour ozone standard. The appropriate air quality impact assessment procedures are those in the PSD regulations, 40 CFR 52.21, which were followed by Duke. Although this argument may have some emotional appeal, there is no legal requirement to address the impacts of the facility on the nearest ozone nonattainment areas, much less on areas that have not yet been designated as nonattainment for the pollutant of concern. The 8-hour standard is not an enforceable standard that the Division or EPA can use to impose additional control requirements on facilities. As such, the 8-hour standard is irrelevant in the permitting process for this Duke facility. In addition, it is not practical to model the impacts on a source-by-source basis. Since ozone is formed by complex reactions involving sunlight, NO_x and VOC emissions it is difficult to model the ozone contribution of individual sources. The Ozone exceedances in the cities of Macon and Augusta are not caused by the Duke Energy facility. The new 8 hour Ozone standard has not been finalized and promulgated as it has been challenged in courts. Thus the Division has no grounds or basis to deny this permit.

34. **THE LIMIT SET FOR NOX IS NOT BACT**

Comment: The draft permit establishes BACT emission limits for NO_x from the turbines as 10 ppmvd at 15% oxygen on gas, achieved with dry low NO_x combustors, and 42 ppmvd at 15% oxygen on fuel oil, achieved with water injection. The draft permit also limits NO_x to 90.5 tons per year. The commenter voiced concern that these limits do not represent BACT because (1) there are permitted simple cycle peaking power plants with lower NO_x limits using SCR, XONONTM, or SCONO_xTM, or solely with dry low NO_x burners; (2) the Division's BACT environmental analysis for Hot SCR is incorrect; (3) it excludes startup, shutdown, and malfunction; (4) the Division did not limit the hourly NO_x mass emission rate; (5) the BACT analysis did not consider when the maximum amount of NO_x would be released into the atmosphere; (6) the economic analysis was flawed by only

analyzing the total annualized cost at base load operation; and (7) the Division was arbitrary and capricious in their decision as to what BACT is deemed cost effective. The commenter states that BACT should be set at 3 ppmvd at 15% oxygen with a one-hour averaging time for natural gas and 6 ppmvd for oil with the use of SCR, SCONOx, or XONON. The commenter also states that BACT should be set at 9 ppmvd with a three-hour average with only dry low NOx burners (they do not state which fuel type is associated with this numerical value).

Response: The commenter asserts that “BACT is a nation-wide standard.” The Division argues that this phrase does not automatically mean that a new facility in one area will have an identical emission limit as the same type of facility in another area. The US EPA Environmental Appeals Board *In re Three Mountain Power, LLC* [PSD Appeal No. 01-05 decided May 30, 2001] stated, “At the outset, we note that BACT is a site-specific determination and that the combined results of the considerations that form the BACT analysis are the selection of an emission limitation and a control technology that are specific to a particular facility.” EPA also notes in their January 4, 1979 Memo entitled *Guidance for Determining BACT under PSD*, “. . . BACT is to be determined on a case-by-case basis rather than automatically applying an applicable Federal New Source Performance Standard (NSPS) . . . In the context of case-by-case BACT, consistency does not necessarily mean that a new facility in one area will have an identical emission limit as the same type of facility in another area. Consistency means that a consistent approach is used in determining BACT and that the impacts of alternative emission control systems are measured by the same set of parameters, although evaluation of specific parameters is done on a case-by-case basis.”

Contrary to some opinions, combustion turbines are not “off-the-shelf” items that demonstrate identical characteristics. Differences can be pronounced when comparing the turbines supplied by different manufacturers sometimes even by the same manufacturer for the same model. With that said, the Division will now consider the commenter’s other points.

The commenter asserts that other states have permitted a large number of simple cycle peaking power plants with NOx limits of 2 to 5 ppmvd at 15% oxygen on gas using the XONONTM or SCONOxTM systems. The Division is very interested in learning about such permits; however, the commenter has not backed up this assertion with specific examples where the XONONTM or SCONOxTM systems have been required in a BACT analysis for an E-class turbine (nominally 80 MW). The Division has documented the results of its search for turbines permitted and operating with the XONONTM or SCONOxTM systems in the PD at 9 through 10. The commenter was silent on any other examples to update the PD at 9 through 10. With this in mind, the Division still maintains that the XONONTM system is not yet offered by General Electric (GE) as an option on its E-class (nominally 80 MW) machines. PD at 9. As stated in the PD at 10, the temperature of the GE 7EA turbine exhaust flow entering the SCONOx system is expected to be greater than 1000 deg F which is well outside the SCONOx operating range. PD at 10. In addition, the content of the comment still leads the Division to maintained that there are no proven installations of the SCONOxTM system on simple-cycle units such as the 80 MW GE 7EA turbines proposed for the project. PD at 10. The Division asserts that it did not err in concluding that BACT does not constitute the use of the XONONTM or SCONOxTM systems.

The commenter asserts that other states have permitted a large number of simple cycle peaking power plants with NOx limits of 2 to 5 ppmvd at 15% oxygen on gas using hot SCR. The Division agrees that the use of hot SCR is technically feasible. PD at 11. Based on information received from Kentucky Division for Air Quality the Kentucky turbine facility cited in the comment applied for a synthetic minor permit and proposed the use of the SCR controls in order to avoid triggering PSD for

NOx. Therefore, this technology was not required pursuant to a BACT analysis and determination, but instead was proposed voluntarily by the permittee to avoid PSD and BACT evaluation for NOx. The Division analyzed the economic impact of using “hot” SCR in its BACT analysis for NOx. PD at 12. In fact, the Division analyzed the economics of hot SCR in the PD at 12 under a variety of scenarios. Adjusting the total annualized cost (PD at 13) according to comment 1 above still results in a hot SCR cost effectiveness of greater than \$10,000 per ton of NOx removed. The Division utilized the NSR Workshop Manual at B.36 through B.46 to assess whether such a dollar value per ton removed is cost effective in this case. The Division maintains that, in this case, the use of hot SCR is not cost effective and does not constitute BACT. PD at 13.

The commenter voiced concern that the total annualized cost data in the permit application for hot SCR may only be accurate for operations at base load. The commenter indicated that the cost effectiveness to control NOx by hot SCR could decrease if the plant was operated at partial load. With this in mind, the Division believes that the magnitude of the NOx cost effectiveness would not change because the tons per year of NOx reduction would be lower at partial load. Note that information in the permit application illustrates that the applicant believes that NOx emissions will be lower at partial loads than at base load.

The commenter voiced concern that the Division did not perform the NOx BACT analysis properly because they believe that the applicant will most probably operate this facility on hot dry days in the summer. The Division maintains that the NOx BACT analysis at PD 9 to 15 is consistent with the EPA NSR Workshop Manual at Chapters B and C.

The commenter asserts that there are other PSD permits for simple cycle plants which establish a lower NOx BACT limit when solely using dry low NOx burners. The Division is aware of that as shown in PD at 13. In support of its argument that the Division erred in selecting a NOx emission limit greater than 9 ppm, the commenter references a Florida PSD Permit in Exhibit 3 at 8 and an undefined Indiana PSD Permit. The commenter’s package did not include a Florida PSD Permit in Exhibit 3 nor anywhere else in their package. The Division believes that the commenter is referring to Construction Permit No. CP 083-12674-00043 issued to Duke Energy Knox, LLC in Wheatland, Indiana and to Permit No. PSD-FL-304 to Pompano Beach Energy, LLC in Broward County, Florida. In addition, the commenter requested that the NOx BACT limit be set at 9 ppmvd at 15% oxygen over a three hour average if SCR, XONONTM, or SCONOxTM are rejected as BACT. The Division carefully reviewed the mentioned Florida and Indiana cases in addition to the Division’s BACT analysis in PD at 13 through 15.

First, the Division reviewed the Pompano Beach Energy, LLC case. The combustion turbines for the Pompano Beach Energy, LLC case are GE7FA combustion turbines (nominally rated at 170 MW) while the combustion turbines for the Duke case are GE7EA combustion turbines (nominally rated at 80 MW). These turbines are not at all identical or similar and thus the Division rejects the commenter’s assertion that the Pompano Beach Energy case should be used to set the NOx BACT limit in this case.

The Division proposed a NOx BACT limit at 10 ppmvd averaged over three hours with the use of dry low NOx burners during natural gas combustion. The commenter requested that the Division revise the NOx BACT limit to 9 ppmvd at 15% oxygen on a 3 hour average if the use of hot SCR is rejected. The Division revisited the PD at pages 13 through 15 where a review of the appropriate numerical value for the limit and averaging period was documented. As stated in PD at 15, the Division considered setting the NOx BACT limit at 9 ppmvd at 15% oxygen, on a 3 hour average, for the turbines in question while firing natural gas; however, the Division is concerned that there is the

likelihood that the actual NOx emissions will be higher than 9 ppmvd at 15% oxygen, on a 3 hour average, when considering the entire operating range of the turbines. The commenter has not provided any data to prove contrary to or update the information on PD pages 13 through 15 in which the Division considered actual operating experience in setting the proposed BACT.

Based on recent EPA data, there are several sources whose permitted NOx limit is 9 ppmvd at 15% oxygen for combustion turbines in conjunction with natural gas with a range of averaging periods. The PD at 13 defines those sites known at the time of development of the draft PSD permit for Duke Energy Sandersville. The following table updates those findings:

Facility	Permitted NOx Emission Limit ppmvd at 15% oxygen
FL – Hardee Power Partners (TECO)	9 ppm on a 3 hr avg for Initial Test for NG 9 ppm on a 24 hr avg with CEMS for NG 42 ppm for FO
FL – Florida Power Corp – Intercession City	9 ppm on a 3 hr avg for Initial Test for NG 10 ppm for NG on a 3hr avg – With CEMS 42 ppm for FO
WI – Wisconsin Public Service	9 ppm on a 24 hr avg for NG 20 ppm on peak power mode for NG – Limited to 100 hrs/yr 42 ppm for FO
TX – City of Garland	9 ppm for NG
MO – Kansas City Power & Light – Hawthorn Units 7&8	9 ppm on a 30-day rolling average for NG
IL - Enron, Des Plaines	9 ppm on an annual average for NG 12 ppm on a monthly average for NG 15 ppm on a 1-hr average
Air Liquide – A cogeneration project. Turbine is not equipped with NOx CEMS	9 ppm on an annual average
Oleander Brevard	9 ppm on a 24 hr average for NG
Vandolah Haredd	9 ppm on a 24 hr average for NG
Enron, Kendall	9 ppm on an annual average for NG 12 ppm on a monthly average for NG 15 ppm on a 1-hr average
Wrightsville Power Facility	9 ppm on a 24 hour average for NG
MN - Lakefield Junction Generating Station	9 ppm on a 3 hour average for NG at or below base load 42 ppm on a 3 hour average for FO
CO - Tri-State Power, LLC – Limon Generating Station	9 ppm on a 1 hour average for NG 42 ppm on a 1 hour average for FO
FL – Duke Energy Lake, LLC	12 ppm on a 3 hour average for CEMS after Initial Test for NG
FL –Duke Energy Fort Pierce, LLC	10.5 ppm on a 3 hour average for CEMS after Initial Test for NG
IN – Duke Energy Knox, LLC	9 ppm on a 24 hour average for NG 42 ppm on a 3 hour average for FO

The PD at 14 has been updated as follows:

Facility	Emission Rates ppmvd @ 15% oxygen
FL – Hardee Power Plant	NOx emissions typically range from 7-8 during natural gas combustion. Tested Emission Rates: <u>Natural Gas Firing; Dry Low NOx Burners</u> NOx = 6.66 <u>Fuel Oil Firing; Water Injection</u> NOx = 39.9
FL – Florida Power Corp – Intercession City Plant	NOx emissions can range from 6.5 to 9.8
MO – Kansas City Power & Light – Hawthorn Units 7&8	NOx emissions range from 7-8 depending on the unit, for natural gas firing.. Unit 7 emissions are higher than Unit 8 emissions.
WI – Madison Gas & Electric in Marinette, WI (Formerly Wisconsin Public Service)	NOx emissions range from 8.7 to 8.9 (natural gas firing) using Part 75 Appendix E – Units not equipped with NOx CEMS.
Duke Energy Madison, LLC – Madison Generating Station	Permitted at 12 ppm for NG and 42 ppm for FO Real Time NOx data during NG combustion: 6 ppm to 10 ppm
Duke Energy Vermillion Generating Station	Permitted at 12 ppm for NG and 42 ppm for FO Real Time NOx data during NG combustion: 6 ppm to 10 ppm
Georgia Power – Jackson County Combustion Turbine Project (Plant Dahlberg)	Permitted at 12 ppm for NG at or below base load and 42 ppm for FO Real Time NOx data during NG combustion: 6 ppm to 12 ppm

Currently, there is very limited operational CEMS data available for turbines guaranteed to achieve 9 ppmvd at 15% oxygen. Duke Energy Madison and Duke Energy Vermillion have limited CEMS operational data available. Based on the Vermillion CEMS data, the Indiana OAQ has determined that the source can maintain a 9 ppmvd at 15% oxygen limit during steady-state operations. The Indiana OAQ noted that even though there is an issued permit requiring a 9 ppmvd at 15% oxygen limit based over a one(1) hour average, the Indiana OAQ believes that this averaging time is not flexible enough for the operation of a simple cycle GE 7EA combustion turbine and may not be achievable based on the Vermillion Generation Stations operating data. Thus, they set the NOx BACT limit at 9 ppmvd at 15% oxygen based over a 24 operating averaging time to allow for more operational flexibility for Duke Energy Knox, LLC. The Division believes that this NOx BACT limit is roughly equivalent to that proposed for the Duke Energy Sandersville facility, namely 10 ppmvd at 15% oxygen on a 3 hour average.

The Division contacted the Colorado Department of Public Health and Environment concerning the availability of operational CEMS data for turbines and the basis for setting the NOx BACT for the Tri-State Power –Limon Generating Station. No operational CEMS data was available and no clear reason for setting the NOx BACT at the permitted limit was provided.

The Division reviewed operational CEMS data for Plant Dahlberg. Based on the Dahlberg CEMS data submitted, the Division has determined that those GE 7EA combustion turbines cannot maintain a 9 ppmvd at 15% oxygen during steady state operations.

Based on the Division's findings, the Division believes that a 9 ppmvd at 15% oxygen limit on a 3 hour average may not be consistently achievable during steady state operations for the GE 7EA combustion turbines proposed for the Duke Energy Sandersville site. The Division believes that it is not in error in considering whether the applicant can achieve compliance at 9 ppmvd at 15% oxygen averaged over 3 hours on a consistent basis. The U.S. EPA Environmental Appeals Board (EAB) has recognized that permitting agencies have the discretion to set BACT limits at levels that do not necessarily reflect the highest possible control efficiencies but, rather will allow the permittee to achieve compliance on a consistent basis. [*In re Three Mountain Power, LLC* PSD Appeal No. 01-05 dated May 30, 2001]. In addition the EAB noted that there is nothing inherently wrong with setting an emission limitation that takes into account a reasonable safety factor. They continue that "The inclusion of a reasonable safety factor in the emission limitation calculation is a legitimate method of deriving a specific emission limitation that may not be exceeded."

With this in mind, the Division maintains that the NO_x BACT limit should be 10 ppmvd at 15% oxygen averaged over three hours. This condition is not changed based on this comment.

Condition 2.8 a is not revised based on this comment.

35. **THE LIMIT SET FOR CO IS NOT BACT**

Comment: The draft permit establishes the BACT emission limits for CO from the turbines at 25 ppmvd at 15% oxygen on gas and 20 ppmvd at 15% oxygen on fuel oil. The commenter voiced concern that these limits do not represent BACT because (1) there are permitted simple cycle peaking power plants with lower CO limits; and (2) the Division failed to consider the ozone formation that will occur from the CO. The commenter states that BACT should be set at 2 ppmvd at 15% oxygen with the use of catalytic oxidation required during periods of natural gas and fuel oil combustion.

Response: The commenter asserts that other states have permitted simple cycle peaking power plants with CO limits of 2 to 6 ppmvd at 15% oxygen on oil and gas, achieved using an oxidation catalyst. The Division agrees that the use of catalytic oxidation is technically feasible. PD at 16. The Division analyzed the economic impact of using catalytic oxidation in its BACT analysis for CO. PD at 16 and 17. Adjusting the total annualized cost (PD at 13) according to comment 1 above still results in a catalytic oxidation cost effectiveness of approximately \$10,400/ton of CO removed. The Division maintains that, in this, case the use of catalytic oxidation is not cost effective and thus does not constitute BACT (note that each turbine will not be allowed to operate more than 2500 hours during any twelve consecutive months). PD at 17. With this in mind a CO BACT emissions limit of 2 ppmvd at 15% oxygen for natural gas and fuel oil combustion is not BACT since the use of catalytic oxidation is rejected.

The commenter asserts that there are other PSD permits for simple cycle plants which establish a lower CO BACT limit for the sole use of dry low NO_x burners. In support of its argument that the Division erred in selecting the CO BACT emission limit, the commenter references a Florida PSD Permit in Exhibit 3 at 9. The commenter's package did not include a Florida PSD Permit in Exhibit 3 nor anywhere else in their package. The Division believes that the commenter is referring to Permit No. PSD-FL-314 to Deerfield Beach Energy, LLC in Broward County, Florida. The Division carefully reviewed this case in addition to the Division's BACT analysis in PD at 17 through 20.

First, the Division reviewed the Deerfield Beach Energy, LLC case. The combustion turbines for the Deerfield Beach Energy, LLC case are GE7FA combustion turbines (nominally rated at 170 MW) while the combustion turbines for the Duke case are GE7EA combustion turbines (nominally rated at 80 MW). These turbines are not at all identical or similar and thus the Division rejects the commenter's assertion that the Deerfield Beach Energy case should be used to set the CO BACT limit in this case.

The commenter voiced concern that the Division's CO BACT analysis did not consider the effect that CO emissions have on ozone formation. The Division maintains that CO is not regulated as an ozone precursor.

The Division has carefully considered the available information for setting the CO emissions limits that meet the requirements of BACT. PD at 17 through 20. With this in mind, the Division maintains that the CO BACT limit should be 25 ppmvd at 15% oxygen averaged over three hours for natural gas combustion and 20 ppmvd at 15% oxygen averaged over three hours for fuel oil combustion. This condition is not changed based on this comment.

36. THE BACT LIMIT FOR SOX SHOULD BE ACHIEVED BY ONLY BURNING NATURAL GAS

Comment: The draft permit establishes BACT for SO₂ as the use of natural gas and low sulfur fuel oil. The project proposes to use fuel oil that contains sulfur not in excess of 0.05 weight percent as a backup fuel with a limit of 500 hours per combustion turbine per twelve month period as well as use the same fuel in the firewater pump P1. The commenter maintains that these limits do not constitute BACT because the Division's analysis is not a top-down BACT analysis. The commenter made the assertion based on the fact that the Division's analysis did not include the use of lower sulfur distillate fuel oil containing only 30 ppmw sulfur and to 15 ppmw when it becomes available, but no later than June 2006. In addition, the commenter noted that the BACT analysis should have resulted in a permit condition that limits the use of fuel oil to periods of natural gas supply interruption and natural gas supply curtailment.

The commenter's second argument against the proposed BACT is that the use of distillate fuel oil is inappropriate and has far-reaching social and economic implications for Georgia. The commenter also noted that the combustion of distillate fuel oil would produce "diesel exhaust" which is recognized by the U.S. EPA and California as a potent human carcinogen and respiratory irritant.

Lastly, the commenter requested that Condition 2.3 identify the natural gas as "pipeline quality" natural gas.

Response: The Division revisited the SO₂ BACT analysis at PD 20 through 21 based on this comment. Ultra Low sulfur (i.e., 30 ppmw) diesel cannot be handled using the same equipment (i.e. delivery trucks / storage tanks) as very low sulfur fuel, due to the fact that contamination between low and ultra low sulfur fuel presents a serious logistical problem that fuel suppliers have not yet been able to reconcile. As such, using ultra low sulfur diesel would require dedicated delivery facilities / delivery trucks, which would have to be accounted for in a BACT analysis before their use could be required. In addition, the cost for this type of fuel would have to be quantified in order to determine if its use is cost effective. Due to the infrequent need for fuel oil at the facility, use of Ultra Low Sulfur fuel will not be practical as a backup fuel until its use as an "over the road" fuel becomes more acceptable as a commercially reasonable practice. Also the low sulfur diesel fuel is a backup fuel only and not a fuel of choice, which is natural gas. Thus, Duke is likely to fire low sulfur diesel fuel in the turbines only during natural gas supply interruptions. It is not economical to produce electricity

from diesel fuel compared to natural gas. The small quantity of diesel fuel likely to be used at the facility does not make it cost effective to require Duke to use the ultra low sulfur diesel fuel which won't be available till 2006. There is some uncertainty regarding the highway diesel ultra low sulfur diesel fuel rule as it is being litigated in the court.

Of course it goes without saying that all natural gas used at the facility shall be pipeline quality natural gas. Condition 2.3 has been revised as per commenter's request to qualify all gas used at the facility to be pipeline quality natural gas. Pipeline quality natural gas is the only source of natural gas to this facility.

The air quality impact analysis included an assessment of the maximum concentrations of air toxics compared to Georgia Air Toxics Guideline. PD at 29. The air toxics analysis found the ambient concentrations of all air toxics to be less than the State specified AAC (Acceptable Ambient Concentration) levels for this project.

The Division stands by the decision in the preliminary determination for the choice of backup fuel. The permit has not been changed based on this comment.

37. THE PERMIT SHOULD CONTAIN A BACT LIMIT FOR VOCs

Comment: The draft permit does not contain a BACT emission limit for VOCs because the permit application claims that the emissions of VOCs will be below the significant threshold. The commenter maintains that this statement was concluded based on an erroneous analysis. The commenter maintains that the Division's conclusion only holds at 100% load. The commenter maintains that the potential to emit of VOCs should be determine by finding out the load at which VOCs are highest and multiplying this emission rate times 2500 hour per year times eight turbines.

Response: The Division computed facility-wide potential VOC emissions to be approximately 28.3 tons per year. PD at Appendix B. Potential VOC emissions were computed using the vendor supplied emission rates at -6 deg F and at base load.

The potential VOC emission rate for natural gas combustion ranges from 1.2 lb/hr to 3 lb/hr. The emission rate of 3 lb/hr occurs at 75% load and -6 deg F. If that value is used, potential VOC emissions from natural gas combustion are computed as follows:

$$\text{VOC PTE (tons/yr)} = (3 \text{ lb/hr}) * (8 \text{ turbines}) * (2500 \text{ hours per year}) * (1 \text{ ton}/2000 \text{ lb})$$

$$\text{VOC PTE (tons/yr)} = 30 \text{ tons per year}$$

The potential VOC emission rate for fuel oil combustion ranges from 3 to 5.5 lb/hr. If the maximum emission rate for each fuel type is used, potential VOC emissions from combusting both natural gas and fuel oil are computed as follows:

$$\text{VOC PTE (tons/yr)} = [(3 \text{ lb/hr}) * (2000 \text{ hrs/yr}) + (5.5 \text{ lb/hr}) * (500 \text{ hrs/yr})] * (8 \text{ turbines}) * (1 \text{ ton}/2000 \text{ lbs})$$

$$\text{VOC PTE (tons/yr)} = 35 \text{ tons per year}$$

The commenter did not provide any substantiation to their claim that the facility-wide potential VOC emissions are equal to or greater than 40 tons per year and so it is hard for the Division to address this comment. The Division maintains that this facility does not trigger PSD for VOC emissions since the facility-wide potential to emit is less than 40 tons per year.

The Division has included a requirement that the Permittee conduct a VOC performance test during periods of natural gas combustion and fuel oil in order to address the commenter's concern.

38. THE BACT EMISSION LIMITS FOR NO_x DO NOT CONTAIN AVERAGING TIMES

Comment: The “note” under Condition 2.0 states that averaging times are tied to or based on the run times specified for the applicable reference test method for demonstrating compliance. A better approach is to simply write the average times in the permit. As it appears that almost every other permitting agency in the country has adopted this approach, it is difficult to understand what legitimate goal the Division can be hoping to achieve by its ambiguous incorporation by reference.

The draft permit states that method 7E and method 19 shall be used for determining NO_x emissions. See Draft Permit, Condition 4.1. The permit is not practically enforceable because it does not specify which method to use. In any event, Method 7E does not contain a run time. Therefore, the draft permit does not have an averaging time for the NO_x limit. We recommend that the Division write in the averaging time of a three-hour rolling average into Section 2 of the permit.

Lastly, the commenter noted, in the public hearing on October 23, 2001, that Condition 4.1.f should be revised because it allows the applicant to only test for filterable PM.

Response: The BACT emission limitations are tied to or based on the run time(s) specified for the applicable reference test method(s) or procedures required for demonstrating compliance.

The applicable reference test method for NO_x in this case is Method 7E. The Division has corrected Condition 4.1g to read as follows: "Method 7E shall be used for the determination of nitrogen oxide emissions. The sampling time for each run shall be one hour." With this revision, the averaging period, as specified by Method 7E, is 3 hours.

The applicable reference test method for CO in this case is Method 10. The Division has corrected Condition 4.1i to read as follows: “Method 10 shall be used for the determination of carbon monoxide concentration. The sampling time for each run shall be one hour.” With this revision, the averaging period, as specified by Method 10, is 3 hours.

The applicable reference test method for total particulate matter in this case is Method 5T and not Method 5 or 5T as found in the draft permit. The Division has corrected Condition 4.1.f to read as follows: “Method 5T shall be used for the determination of particulate matter concentration. The minimum sampling time for each run shall be one hour.” With this revision, the averaging period, as specified by Method 5T, is 3 hours.

Method 19 is not an alternative to Method 7E. The applicable procedure in Method 19 is used to convert the tested emission rate from Method 7E (in ppm) to lb/MMBtu, if necessary.

39. THE DRAFT PERMIT IMPERMISSIBLY EXEMPTS VIOLATIONS DURING STARTUPS, SHUTDOWNS AND MALFUNCTIONS

Comment: The commenter asserts that the draft permit impermissibly exempts violations during startups, shutdowns and malfunctions for the following reasons: (1) Contains no limits on the number of startups/shutdowns; (2) Contains no emission limits for periods of startup, shutdown, and malfunctions; (3) is not consistent with the requirements of the Clean Air Act; (4) The U.S. EPA has consistently defined startup and shutdown to be part of the normal operation of a source; (5) Is inconsistent with permits issued by other states which include limits on startup and shutdown emissions. The commenter requests that the permit be revised to include conditions which limit the number, duration, and emissions during startup and shutdown or a condition which imposes a mass emissions limit on emissions on startup, shutdown, malfunction, and steady-state operations.

Response: Draft Condition 8.12 (Final Condition 8.3) defines how excess emissions resulting from startup, shutdown, and malfunction are analyzed for the purpose of verification of compliance with the applicable PSD BACT limits. The Division cited the legal authority for this requirement as Georgia Rule 391-3-1-.02(2)(a)7. The Division maintains that Draft Condition 8.12 (Final Condition 8.3) does not provide for an automatic exemption (i.e., if certain conditions existed during a period of excess emissions, then those exceedances would not be considered violations). For periods of excess emissions, the language in Draft Condition 8.12 (Final Condition 8.3) puts the burden of proof on the Permittee and the merits of which are independently and objectively evaluated by the Division. Also, the Division maintains that Draft Condition 8.12 (Final Condition 8.3) is consistent with the requirements of the EPA Bennett Memorandum.¹

The Division has considered the commenter's concern that the permit does not define startup, shutdown, and malfunction which in turn renders Draft Condition 8.12 (Final Condition 8.3) less effective for its intended purpose. Thus, the Division analyzed how to define startup, shutdown, and malfunction for the proposed facility.

The applicable definitions for malfunction are found in Georgia Rule 391-3-1-.01(nn) and in 40 CFR 60.2. These definitions are applied on a case by case basis for each occurrence of excess and excessive emissions in accordance with Draft Condition Nos. 8.12, 8.14, and 8.16 (Final Condition Nos. 8.3, 8.4, and 8.5). The Division has elected not to include any additional language beyond Georgia Rule 391-3-1-.01(nn) and 40 CFR 60.2 because it is our belief that any attempt to clarify what constitutes an unavoidable malfunction will generally produce an impression of limiting the scope of its content.

The rolling annual BACT emission limits found in Condition Nos. 2.11 and 2.12 only cover normal source operation. The Division maintains that normal source operation does not include malfunctions which meet the definitions found in Georgia Rule 391-3-1-.01(nn) and 40 CFR 60.2. Thus, Condition Nos. 2.11 and 2.12 are not revised to include malfunctions.

The commenter requests that the permit contain limits on the number, duration, and emissions during startups and shutdowns. The applicable definitions for startup are found in Georgia Rule 391-3-1-.01(zzz) and 40 CFR 60.2. The applicable definitions for shutdown are found in Georgia Rule 391-3-1-.01(jjj) and 40 CFR 60.2. The Division agrees with the commenter that periods of startup and shutdown are part of normal source operation.

EPA Region IV was silent on the issue of startup and shutdown in their comments to the proposed permit. Based on discussions with EPA Region IV on this matter in November 2001, the Division proposes to revise the permit as follows to account for startup and shutdown: (1) Define startup and shutdown as in New Condition 2.13; (2) Define record keeping associated with these events; and (3) Revise Draft Condition 8.17.b (Final Condition 8.16.b) to include the definition of exceedances for startup and shutdown.

40. **THE PERMIT MUST CONTAIN A CASE-BY-CASE MACT**

Comment: The Division determined not to apply a case-by-case MACT standard because it assumed that the facility was not a major source of hazardous air pollutants. The commenter maintains that the Division drew this conclusion based on an erroneous analysis. The commenter maintains that the analysis is flawed as follows: (1) the Division noted that CO is an indicator of HAP emissions; (2) potential HAP emissions appear to only be based on 100% load instead of at low load and during

¹ EPA, Office of Air, Noise and Radiation, "Policy on Excess Emissions During Startup, Shutdown, Maintenance, and Malfunctions," Kathleen M. Bennett, September 28, 1982

startup and shutdown when HAP emissions are higher; (3) there are other turbine permits which limit HAPs; (4) the Division used the wrong formaldehyde emission factor. The commenter notes that the correct emission factor should be 3.12×10^{-3} lb/MMBtu based on the background document for AP-42 Section 3.1.

Response: The Division maintains that CO is an indicator of HAP emissions. The U.S. EPA noted in the April 2000 edition of AP-42 Chapter 3.1 (Stationary Gas Turbines) that the formation of carbon monoxide during the combustion process is a good indication of the expected levels of HAP emissions. The U.S. EPA also notes that low CO is an indication of very good combustion and therefore HAP emissions should also be low.

The potential to emit for HAPs as found in PD at 2 are taken from Appendix C of the permit application. Duke noted in this application that the HAP emission factors are taken from the U.S. EPA Inventory Database for Stationary Combustion Turbines, published May 4, 2000. The emission factors represent test results from General Electric turbine models rated greater than 20 MW, which most closely resemble the units to be installed at the proposed plant. The U.S. EPA came out with a memo dated August 21, 2001 which provides insight to the magnitude of HAP emissions from lean premix combustion. This memo came out after issuance of this Preliminary Determination. The proposed turbines are equipped with lean premix combustion (a.k.a. dry low NOx burners). EPA notes in this memo that, "Lean premix combustors emit lower levels of NOx, CO, formaldehyde, and other HAP[s] than diffusion flame combustion turbines. . . lean premix combustion is a comparable technology to oxidation catalyst systems." The commenter said that the formaldehyde emission factor should be 3.12×10^{-3} lb/MMBtu. The Division disagrees with that conclusion because that emission factor is for diffusion flame combustion and not for lean premix combustion. The Division also believes that this emission factor does not necessarily take into account HAP emissions during low loads as the August 2001 EPA memo states that the average formaldehyde emission factor for diffusion flame combustion turbines for all loads is 2.92×10^{-3} lb/MMBtu.

The August 2001 EPA memo notes that the average formaldehyde emission factor for lean pre-mix combustion for high loads (>80 percent) is 6.49×10^{-5} lb/MMBtu. Note that this emission factor is only applicable for natural gas combustion and formaldehyde emissions from the combustion of natural gas are higher than from fuel oil combustion. The Division maintains that the worst case scenario to analyze is 2500 hours per year of natural gas combustion and not 500 hours per year of fuel oil and 2000 hours per year of natural gas combustion. In this particular case, the potential formaldehyde emission rate (for natural gas combustion) is computed as follows:

$$(6.49 \times 10^{-5} \text{ lb/MMBtu}) * (1030 \text{ MMBtu/hr}) * (8 \text{ turbines}) * (1 \text{ ton}/2000 \text{ lb}) = 0.00027 \text{ tpy}$$

The EPA has not specified an average formaldehyde emission rate at low load or at all loads when using lean premix combustion. EPA did note that lean premix combustion is a comparable technology to oxidation catalyst systems. With that in mind, the Division estimated formaldehyde emissions using lean premix combustion operating at low loads as follows:

$$(2.92 \times 10^{-3} \text{ lb/MMBtu}) * (1030 \text{ MMBtu/hr}) * (8 \text{ turbines}) * (1-0.80) * (1 \text{ ton}/2000 \text{ lbs}) * (2500 \text{ hrs/yr}) = 6 \text{ tpy.}$$

(This computation assumes (1) average diffusion flame emission rate over all loads and turbine sizes and (2) an 80% HAP reduction using lean premix combustion).

Table 3 of the August 2001 memo illustrates that the formaldehyde emission factor for diffusion flame combustion turbines for all loads is at least one order of magnitude larger than the other HAPs

listed. Thus, the Division believes that there is very little likelihood of the potential to emit of a single HAP or total HAPs equal to or exceeding 10 tons per year and 25 tons per year, respectively.

The Division has included a formaldehyde testing requirement during periods of natural gas and fuel oil combustion in order to address the commenter's concern.

41. **THE PERMIT LIMITS THE USE OF CREDIBLE EVIDENCE**

Comment: As emphasized by the United States Environmental Protection Agency's (EPA) Credible Evidence Rule, 62 FR 8314 (Feb. 24, 1997), the Clean Air Act (CAA) allows the public, EPD, EPA, and the regulated facility to rely upon any credible evidence to demonstrate violations of or compliance with the terms and conditions of a permit. Specifically, EPA revised 40 CFR § 51.212, 51.12. 52.30, 60.11 and 61.12 to "make clear that enforcement authorities can prosecute actions based exclusively on any credible evidence, without the need to rely on any data from a particular reference test." 62 FR at 8316. EPD must ensure that no permit purports to limit the use of credible evidence. Moreover, the permit should include standard language stating that all credible evidence may be used.

A) EPD Must Remove Language that Purports to Limit Credible Evidence.

EPD must ensure that its permits contain no language that could be interpreted to limit credible evidence. For example, condition 4.1. in the draft permit states that "the methods for the determination of compliance with emissions limits listed under Sections 2.0 which pertains to the emission units listed in Note B are as follows:" One could read this provision to stand for the proposition that when a government agency or member of the public takes an enforcement action for a permittee violating its permit, the enforcer can only rely on information from the methods of determination listed in the permit. This position is directly contrary to the Clean Air Act requirements in CAA §§ 113(a), 113(e)(1) and 40 CFR § 51.212, 51.12. 52.30, 60.11 and 61.12 which allow anyone taking an enforcement action to rely on any credible evidence. Therefore, the aforementioned sentence in Section 4.1 should be stricken.

Another example of the permit's attempt to limit credible evidence is found in Condition 4.2. This condition states that "the Permittee shall conduct the following performance tests on each combustion turbine to demonstrate compliance with BACT emission limits listed in Section 2." Draft Permit at 7. This language should likewise be stricken.

B) EPD Should Include Standard Language in the Permit that Explicitly States that Anyone Can Use Any Credible Evidence

The permit does not affirmatively state that any credible evidence may be used in an enforcement action. EPA supports the inclusion of credible evidence language in all Title V permits. As explained by the Acting Chief of US EPA's Air Programs branch:

It is the United States Environmental Protections Agency's position that the general language addressing the use of credible evidence is necessary to make it clear that despite any other language contained in the permit, credible evidence can be used to show compliance or noncompliance with applicable requirements. A regulated entity could construe the language to mean that the methods for demonstrating compliance specified in the permit are the only methods admissible to demonstrate violation of the permit terms. It is important that Title V permits not lend themselves to this improper construction.

Letter from Cheryl L. Newton, Acting Chief, Air Programs Branch, EPA, to Robert F. Hodanbosi, Chief, Division of Air Pollution Control, Ohio Environmental Protection Agency, dated October 30, 1998. In fact, EPA apparently sent a letter in May 1998 specifically directing EPD to amend its SIP to include language clarifying that any credible evidence may be used. Nevertheless, while three years have elapsed since EPA's request, the permit does not contain the necessary language.

While anyone may rely on all credible evidence regardless of whether this condition appears in the permit, EPD should include credible evidence language in the permits and permit template to avoid unnecessary ambiguity. Specifically, EPA has recommended that the following language be included in all Title V permits:

Notwithstanding the conditions of this permit that state specific methods that may be used to assess compliance or noncompliance with applicable requirements, other credible evidence may be used to demonstrate compliance or noncompliance.

Letter from Stephen Rothblatt, Acting Director, Air and Radiation Division, US EPA, to Paul Deubenetzky, Indiana Department of Environmental Management, dated July 28, 1998. We request that EPD include this provision in the permit to clarify the availability of any credible evidence to demonstrate noncompliance with permit requirements.

Response: The Division has already adopted a credible evidence rule that renders totally unnecessary the inclusion in a permit of a statement that credible evidence may be used in establishing whether a person has violated or is violating an emission standard. See "EPD Procedures for Testing and Monitoring Sources of Air Pollutants," Vol. I, § 1.3(g). That provision makes clear that a specification of a method in EPD's procedures does not preclude the use of credible evidence to establish a violation of an emission limitation or standard.

EPD believes that adequate provisions for consideration of credible evidence have been included in Condition 1.1, which states, in part, that "Determination of whether acceptable operating and maintenance procedures are being used will be based on any information available to EPD which may include, but is not limited to, monitoring results, observations of the opacity or other characteristics of emissions, review of operating and maintenance procedures or records, and inspection or surveillance of the source."

Furthermore, the prescribed performance test methods and procedures, which are incorporated in the Georgia Rules for Air Quality Control, contain clear provisions that, by prescribing such procedures, nothing would preclude the additional use of other credible evidence, either for compliance certifications or for establishing whether or not a source is in violation of any emissions limitation or standard. See Rule 391-3-1.02(3)(a) and the referenced Procedures for Testing and Monitoring Sources of Air Pollutants at Section 1.3(g). Even without this direct inclusion, the Rules themselves are cited in all permits issued by EPD.

EPD has elected not to include any additional language beyond the Rules cited above because it is our belief that any attempt to clarify the rule or define credible evidence will generally produce an impression of limiting of the scope of the rule. This we do not wish to do. EPD believes that any challenge to the authority of the U.S. EPA, State of Georgia, or any citizen with standing to use any credible evidence would easily be turned away. On the other hand, if limiting language such as that offered in the referenced EPA text were to be used, arguments to use such statements to "whither away" at the general principle could and most probably would be made. For instance, petitioners might suggest that the statement was only meant to apply to stated test methods and not work practice

or other parts of the applicable standards, including the general provisions to the rules. Therefore, for the benefit of the enforceability of the standards by using any credible evidence available, the permit need not and is not being modified.

C) THE PERMIT SHOULD REFERENCE CEMS DATA

Comment: In the Pompano Beach Energy Center permit, Florida requires its permittee to use continuous emissions monitoring system (CEMS) data to show compliance with the NO_x limit. Ex. 3 at 8. We recommend that EPD use similar language, in addition to the “any credible evidence” language discussed above.

Response: The commenter is reminded that Exhibit 3 of their response did not include this permit. The commenter is also reminded that the permit requires the installation and operation of a NO_x and CO CEMS which are used as an indicator of compliance.

42. THE PRELIMINARY DETERMINATION DOES NOT ESTABLISH THAT THE FACILITY WILL NOT CAUSE A VIOLATION OF THE PSD INCREMENTS

Comment: The PD does not establish that the facility will not violate any of the allowable increments. The PD does not discuss whether any of the available increments have already been consumed by other sources. Part of the problem is that EPD used a baseline date for SO₂ and NO_x of November 21, 2000. However, 42 U.S.C. § 7479(4) requires that the baseline date be the date when the first PSD permit application was submitted. Therefore, at a minimum, EPD needs to discuss whether all of the relevant increments have already been consumed and also re-set the baseline date to be consistent with 42 U.S.C. § 7479(4).

Response: The Division maintains that the first PSD application received in Washington County which was major for SO₂ and NO_x was on November 21, 2000. The commenter may be referring to the date that the first PSD application received in Washington County which was major for PM₁₀. That date was June 6, 1978. The commenter is incorrect in their apparent assumption that the baseline date needs to be re-set because the PD at Appendix C is consistent with 40 CFR 52.21.

The commenter asserted that the PD did not establish that the facility will not violate any of the allowable increments. The Division disagrees. The PD at 28 shows that the projected concentrations of CO, NO₂, PM₁₀, and SO₂ from the proposed facility are all below the PSD Significant Impact Level. With this in mind, the Division maintains that the proposed facility is not considered to cause or contribute to a violation of the PSD increments. PD at 28. This conclusion is directly consistent with the July 5, 1988 EPA/OAQPS Memo entitled, “Air Quality Analysis for Prevention of Significant Deterioration (PSD).”

43. THERE ARE NO BACT LIMITS FOR OTHER EMISSION UNITS

Comment: The draft permit indicates that the facility includes two low-sulfur diesel fuel storage tanks. The permit should limit the size of the storage tanks. As the permit is written, the Facility could install 50 million gas storage tanks. Obviously, this would effect the emissions from these units.

Response: The commenter is mistaken in the statement that the draft permit indicates two low sulfur diesel fuel storage tanks. The permit references four. In order to clear up apparent confusion, the facility description table under Note B will be updated to indicate the tank capacity.

44. THE PERMIT SHOULD LIMIT SOUND AND LIGHT POLLUTION

Comment: Rule 391-3-1-.02(2)(a)3(ii) allows the director to add additional requirements to safeguard the public health, safety and welfare of the people of the State of Georgia. EPD should use this authority to limit sound and light pollution from this facility. EPD should require Duke to mitigate these impacts through noise control devices and limitations on high intensity external lights at the facility.

Response: The Division reviewed whether the scope of Georgia Rule 391-3-1-.02(2)(a)3 rule includes sound and light pollution. First, the commenter would agree that sound and light pollution would not fall under the category of *emission limitation*. The Division reviewed the Georgia Air Quality Act (a.k.a. O.C.G.A., Section 12-9, et seq.) to ascertain an interpretation of the phrase *or other requirements*. Does this include sound and light pollution? Based on O.C.G.A., Section 12-9, et seq., the Division believes that Georgia Rule 391-3-1-.02(2)(a)3 only applies to emissions of air contaminants. The definition of air contaminants in O.C.G.A., Section 12-9-3(3) does not include sound or light pollution. With this in mind, the permit is not revised based on this comment.

45. EPD NEEDS TO CONSIDER PROJECT RELATED GROWTH

Comment: The commenter voiced concern about the Division's conclusion that the air quality impacts produced by project-related growth would be inconsequential. The commenter noted that this was an inaccurate conclusion because of the following reasons: (1) this project will supply energy to the rapidly developing suburban sprawl in Georgia and the Southeast; (2) the sprawl has significant air quality impacts; and (3) the Division failed to consider air pollution from the increase in natural gas extraction and transportation as a result of project related growth.

Response: Please refer to the PD at 30 for further discussion of this topic. The Division considered the effects that project related growth would have on the surrounding area and the Division believes that it is not expected to be significant.

[Additional Changes](#)

New Condition 2.14 has been added.

Final Condition 5.8 has been updated.

Final Condition 8.17 is new and has been added.

APPENDIX A

FINAL PSD PERMIT 4911-303-0040-P-01-0

APPENDIX B
COMMENTS ON DRAFT PERMIT