Prevention of Significant Air Quality Deterioration Review
Of Pratt Industries (U.S.A.), Inc. – Visy Paper, Inc.
Located in Rockdale County, Georgia

PRELIMINARY DETERMINATION
SIP Permit Application No. 16655
October 2006

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

Stationary Source Permitting Program (SSPP)
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SUMMARY

The Environmental Protection Division (EPD) has reviewed the application submitted by Pratt Industries (U.S.A.), Inc. – Visy Paper, Inc. (Visy Paper) for a permit to construct and operate an Alternative Fuels Power Island (AFPI), and in so doing, to undergo Non-Attainment Area New Source Review (NAA-NSR). The proposed project will consist of an alternative fuels bubbling fluidized bed gasifier, air pollution control equipment, a turbine generator, fuel handling systems, and other equipment. The gasifier will have a nominal heat input rate of 380 MMBtu/hour, and the turbine generator will be able to co-generate approximately 8 MW of electricity. For fuel, the facility will use natural gas (for startup and flame stabilization only), paper sludge, heavy rejects, dry scrap construction wood, tire derived fuel, and carpet remnants.

Visy Paper, and the two other facilities located on the Part 70 site – Jet Corr, Inc. (Jet Corr) and Jet Corr II, Inc. (Jet Corr II) - are located in Rockdale County, one of the original 13 counties designated as non-attainment for ground level ozone in the Atlanta Metro Area under the U.S. EPA 1-hour standard, as well as the new 8-hour ozone standard. As of January 1, 2004, Rockdale County is classified as being in severe non-attainment with the 1-hour ozone standard, meaning that the Prevention of Significant Deterioration (PSD)/NSR major source threshold for VOC and NO_X (ground level ozone precursors) has been lowered to 25 tons per year. Rockdale County lies within the boundaries of the current 8-hour ozone Atlanta Non-Attainment Area and the PM 2.5 Atlanta Non-Attainment Area. The site is defined as a "major stationary source" since the combined facilities have a potential to emit 100 tons per year or more of several criteria pollutants subject to regulation under the Clean Air Act. The combined site is considered a major source under PSD regulations for CO and SO_2 since potential emissions exceed 100 tons per year for each pollutant. The combined site is also considered a major source under NAA-NSR regulations for VOC and NO_X since potential emissions are greater than 25 tons per year for each pollutant. As part of this project, the facility has agreed to limit NOx, CO, and SO2 emissions, on a site-wide basis, below 100 tons per year. Therefore, the facility becomes a minor source with regard to the PSD regulations but is still a major source under the Non-Attainment NAA-NSR regulations.

The EPD review of the data submitted by Visy Paper related to the proposed modifications indicates that the project will be in compliance with all applicable state and federal air quality regulations.

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 NO_X. While 40 CFR 51.165 requires the application of Lowest Achievable Emission Rate (LAER), Visy Paper, by accepting a limit of 100 tons per year from the entire site, was able to utilize BACT in place of LAER per Georgia Air Quality Rule 391-3-1-.03(8)(c)13(iii).

To satisfy the offsetting emission reduction credit requirement of 40 CFR 51.165, Visy Paper must obtain NOx emission offsets equal to 1.3 times the potential emissions of the proposed modification. This requirement of 40 CFR 51.165 is in place to ensure that there is a net reduction in the non-attainment pollutant of concern (in this case, NO_X). Since acquiring the emission reduction credits is required to ensure an improvement in air quality by reducing emissions in non-attainment pollutants, ambient air quality modeling is not required. 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.

The Federal Land Manager (FLM) for any Class I area within 200 km of a PSD/NSR major source is required to be notified and given the opportunity to review any application for new construction of modifications. The following Class I Areas are within 200 km of the facility – Cohutta Wilderness Area (145 km), Slickrock/Joyce Kilmer Wilderness Area (190 km), Smokey Mountain National Park (200 km). Additionally, Shining Rock Wilderness Area is 213 km away. The appropriate Federal Land Managers have been copied on the permit application and associated attachments. At the time this preliminary determination document was completed, no objections had been raised from any of the Federal Land Managers.

This Preliminary Determination concludes that an Air Quality Permit should be issued to Visy Paper for the modifications necessary to construct and operate the Alternative Fuels Power Island. Various conditions have been incorporated into the current Title V operating permit to ensure and confirm compliance with all applicable air quality regulations. A copy of the draft permit amendment is included in Appendix A.

1.0 INTRODUCTION

On March 16, 2006, Pratt Industries (U.S.A.), Inc. – Visy Paper, Inc. (hereafter Visy Paper) submitted an application for an air quality permit to construct and operate an Alternative Fuels Power Island (AFPI), which includes an alternative fuels bubbling fluidized bed gasifier (Source Code: PI01), air pollution control equipment, a turbine generator, fuel handling systems, and other equipment. The facility is located at 1800A Sarasota Parkway, Conyers (Rockdale County). An emissions control scheme meeting the standards of Best Available Control Technology (BACT) will be imposed on the facility and offset emission credits, at a 1.3 to 1 ratio, will have to be procured by Visy Paper prior to startup of the AFPI.

Visy Paper (AFS No. 247-00037), Jet Corr (AFS No. 247-00047), and Jet Corr II (AFS No. 247-00052) are one Part 70 source because they are under common control, located on contiguous and/or adjacent property, and have the same 2-digit SIC code. They are all owned and operated by Pratt Industries (U.S.A.), Inc. Visy Paper and Jet Corr are located on the same property, while Jet Corr II is about ¼ mile away. Visy Paper, Jet Corr, and Jet Corr II are one Title V major source because the combined potential emissions of NO_X, CO, SO_2, and VOC exceed 25, 100, 100, and 25 tpy, respectively. As part of this project, the facility has agreed to limit NOx, CO, and SO_2 emissions, on a site-wide basis, below 100 tpy. Therefore, the facility becomes a minor source for these pollutants under the PSD regulations and remains a major source for NOx and VOC emissions under the NAA-NSR regulations.

Based on the proposed project description and data provided in the permit application, the estimated potential emissions of regulated pollutants from the combined site, including the AFPI, are listed in Table 1-1 below:

Table 1-1: Potential Emissions from the Combined Site

Pollutant	Potential Emissions (tpy)	PSD and NAA-NSR Major Source Threshold(tpy)	Subject to NSR or PSD Review?
PM	72.3	100	No
PM_{10}	72.3	100	No
VOC	93.4	25	Yes
NO_X	<100	25	Yes
CO	<100	100	No
SO_2	<100	100	No
HAP	<25	N/A	No

The potential emissions from both the existing facilities and the proposed modification were calculated using worst-case operating scenarios, as well as facility-proposed emission limitations. Please see the Narrative for Permit No. 2631-247-0037-V-01-1 for more information about the emissions calculations.

In determining if a modification triggers NAA-NSR, the creditable emissions increases and decreases during a five consecutive year period must be analyzed. Since Visy Paper anticipates the startup of this unit as March 1, 2008, the five consecutive year period is 2004-2008. Table 1-2 outlines all contemporaneous projects and associated potential emissions.

Table 1-2: NSR Applicability Analysis

Projects	Date	Potential-to-emit (tpy)	
		NOx	**VOC**
Proposed Modification (Application No. TV-16655)			
Visy Paper – AFPI	Mar-08	24.7*	10.8**
Contemporaneous Changes in the Past 5 Years			
Jet Corr: Dryers Emissions (4 units)	Jul-04	2.80	0.15
Jet Corr: FM01, FM09-FM12	Jul-04	0	11.15
Jet Corr II: Boiler JC03	Jun-04	9.16	0.404
Total Emissions		**36.66**	**22.504**
NAA NSR Significant Level		25	25
Exceeding Significant Level?		**Yes**	No

* Based on difference between existing site-wide actual emissions and proposed site-wide emissions limit.
** Proposed boiler limit

Therefore, the modification does trigger NAA-NSR review for NO_X emissions, but not for VOC emissions.

2.0 PROCESS DESCRIPTION

According to Application No. 16655, Visy Paper has proposed to construct and operate an Alternative Fuels Power Island. The Alternative Fuels Power Island (AFPI) will consist of an alternative fuels bubbling fluidized bed gasifier, various air pollution control equipment, a turbine generator, fuel handling systems, and other equipment. The gasifier (Source Code: PI01) will have a nominal heat input rate of 380 MMBtu/hour, and the turbine generator will be able to co-generate approximately 8 MW of electricity. For fuel, the facility will use natural gas (startup and flame stabilization only), paper sludge, heavy rejects, dry scrap construction wood, tire derived fuel, and carpet remnants. The facility plans to install a bag filter to control PM emissions, a lime or sodium bicarbonate addition system to control HCl and SO_2 emissions, and a NOx reduction system, most likely a selective non-catalytic reduction (SNCR) system or a selective catalytic reduction (SCR) system, to control NO_X emissions. Additionally, the facility will use continuous emissions monitors (CEMs) for monitoring NO_X, SO_2, CO, and opacity emissions.

The bubbling fluidized bed is capable of handling a fuel moisture content up to 60%. It inherently minimizes NO_X emissions by utilizing a reduced atmosphere in the bed and staging the combustion. The solid fuel is gasified in a reduced oxygen atmosphere at approximately 1,290°F over a hot fluidized bed of silica sand. Combustion is completed by injection of secondary air in the freeboard area above the bed where the temperature will be above 1,560°F with a minimum residence time of 2 seconds. The combination of using a reduced atmosphere and a staged combustion will minimize NO_X production. Bed fluidization permits the fuel particles to be in continuous contact with the bed media in order to gasify the fuels to completion. The high-pressure steam generated in the gasifier will be routed to the turbine generator; the steam will be exhausted from the turbine at mill operating pressure and routed to the process steam header.

Lime or sodium bicarbonate will be added to the final fuel mix to protect the gasifier from chlorine-induced corrosion. The lime/sodium bicarbonate will act as an alkaline agent to absorb acid gases, primarily HCl and SO_2. The products of combustion exiting the gasifier will be subjected to a further injection of lime/sodium bicarbonate to reduce SO_2 and HCl emissions. The particulate generated by both the combustion process and alkali addition will be removed using a baghouse.

In addition to the reduced NO_X generation resulting from use of the bubbling fluidized bed technology, selective non-catalytic reduction will be installed. If needed, selective catalytic reduction may be used to further control NO_X emissions. Both use a nitrogen-based reagent to react with the NO_X to form elemental nitrogen and water vapor.

The Visy Paper permit application and supporting documentation are included in Appendix B of this Preliminary Determination and can be found online at www.georgiaair.org/airpermit.

3.0 REVIEW OF APPLICABLE RULES AND REGULATIONS

State Rules

Georgia Rule for Air Quality Control (Georgia Rule) 391-3-1-.03(1) requires that any person prior to beginning the construction or modification of any facility which may result in an increase in air pollution shall obtain a permit for the construction or modification of such facility from the Director upon a determination by the Director that the facility can reasonably be expected to comply with all the provisions of the Act and the rules and regulations promulgated thereunder. Georgia Rule 391-3-1-.03(8)(b) continues that no permit to construct a new stationary source or modify an existing stationary source shall be issued unless such proposed source meets all the requirements for review and for obtaining a permit prescribed in Title I, Part C of the Federal Act [i.e., Prevention of Significant Deterioration of Air Quality (PSD)], and Section 391-3-1-.02(7) of the Georgia Rules (i.e., PSD).

Georgia Rule (d) [391-3-1-.02(2)(d)] limits opacity and particulate matter (PM) emissions from all fuel-burning equipment. It also limits NO_X emissions from equipment with a maximum heat input capacity of greater than 250 MMBtu/hour. The AFPI is subject to an opacity limit of 20% or less, except for one six minute period of not more than 27%. The limit of 0.10 lb/MMBtu of particulate matter is subsumed by the 40 CFR 60 Subpart Db limit of 0.03 lb/MMBtu. The limit of 0.2 lb/MMBtu of NOx while firing natural gas is subsumed by the requested BACT limit of 0.07 lb/MMBtu.

Georgia Rule (g) [391-3-1-.02(2)(g)] limits sulfur dioxide (SO_2) emissions from fuel-burning equipment with a heat input rate greater than 250 MMBtu/hour. It also limits sulfur content in the fuel used in the equipment. The AFPI is subject to 1.2 lb/MMBtu of SO_2 when firing solid fossil fuel or derived from solid fossil fuel and wood residue. Rule (g) limits the sulfur content of all fuel burned in this boiler to three (3) percent sulfur, by weight, since the boiler is rated at greater than 100 MMBtu/hour; however, because Visy Paper will be utilizing an SO_2 abatement system, they are allowed to burn fuel with sulfur content exceeding 3 percent as long as the emissions of sulfur dioxide do not exceed the amount that would be emitted if they were burning 3 percent sulfur with no abatement technology being utilized.

Georgia Rule (tt) [391-3-1-.02(2)(tt)] requires sources with potential emissions of VOC exceeding 25 tons per year in Rockdale County to apply Reasonably Available Control Technology (RACT) to reduce those VOC emissions. The AFPI is required to be in compliance upon startup. The public must be given an opportunity for public comment and a hearing, and the proposed VOC RACT plan will be submitted to EPA as a revision to the State Implementation Plan for the Atlanta 8-Hour Ozone Non-Attainment Area.

Georgia Rule (yy) [391-3-1-.02(2)(yy)] requires sources with potential emissions of NO_X exceeding 25 tons in Rockdale County to apply Reasonably Available Control Technology (RACT) to reduce those NO_X emissions. The AFPI is required to be in compliance upon startup. The public must be given an opportunity for public comment and a hearing, and the plan will be submitted to EPA as a revision to the State Implementation Plan for the Atlanta 8-Hour Ozone Non-Attainment Area.

Georgia Rule 391-3-1-.03(8)(c) - This Georgia Rule contains the elements of the Federal New Source Review provisions. This section of the Georgia Rules for Air Quality Control applies to newly constructed or modified existing sources, located in a Non-Attainment Area, whose potential emissions of any regulated pollutant exceed the major source threshold (in this case, 25 tons per year of NO_X). This section also applies to existing sources making a modification whose potential emissions exceed the major modification emission thresholds listed in 40 CFR 52.24(f)10. Sources being permitted under these provisions are required to:

a. obtain offsetting emission reduction credits prior to startup;

b. comply with the LAER as determined using the RACT/BACT/LAER Clearing House (RBLC) and other authoritative sources;

c. certify that all other major stationary sources owned or operated by the Permittee are operating in compliance, or are on a schedule of compliance; and

d. submit an analysis of alternative sites, sizes, production processes and environmental control techniques for the proposed source to determine whether the benefits of the proposed source significantly outweigh the environmental and social costs imposed as the result of its proposed location, construction, or modification.

The State must have, and operate under, an approved State Implementation Plan (SIP) in accordance with Title I, Part D of the Federal Act.

Also, 391-3-1-.03(8)(c)13(iii) allows for a major stationary source located in the 13-county Atlanta Metro Area non-attainment area (including Rockdale County) which emits or has the potential to emit less than 100 tons of VOC or NO_X per year, to apply BACT, as defined by the Federal Act, in lieu of the LAER for any modification at the source.

Federal Rule – NSR – 40 CFR 51.165

The provisions of Statutory Restriction on New Sources (NSR) in 40 CFR 51.165 have been implemented into Georgia's SIP in Georgia Rule 391-3-1-.03(8)(c). For a discussion of these provisions, see the discussion in the previous section.

Federal Rule - PSD

The regulations for PSD in 40 CFR 52.21 require that any new major source or modification of an existing major source be reviewed to determine the potential emissions of all pollutants subject to regulations under the Clean Air Act. The PSD review requirements apply to any new or modified source which belongs to one of 28 specific source categories having potential emissions of 100 tons per year or more of any regulated pollutant, or to all other sources having potential emissions of 250 tons per year or more of any regulated pollutant. They also apply to any modification of a major stationary source which results in a significant net emission increase of any regulated pollutant.

The PSD regulations require that any major stationary source or major modification subject to the regulations meet the following requirements:

- Application of BACT for each regulated pollutant that would be emitted in significant amounts;
- Analysis of the ambient air impact;
- Analysis of the impact on soils, vegetation, and visibility;
- Analysis of the impact on Class I areas; and
- Public notification of the proposed plant in a newspaper of general circulation

Definition of BACT

The PSD regulation requires that BACT be applied to all regulated air pollutants emitted in significant amounts. Section 169 of the Clean Air Act defines BACT as an emission limitation reflecting the maximum degree of reduction that the permitting authority (in this case, EPD), on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such a facility through application of production processes and available methods, systems, and techniques. In all cases BACT must establish emission limitations or specific design characteristics at least as stringent as applicable New Source Performance Standards (NSPS). In addition, if EPD determines that there is no economically reasonable or technologically feasible way to measure the emissions, and hence to impose and enforceable emissions standard, it may require the source to use a design, equipment, work practice or operations standard or combination thereof, to reduce emissions of the pollutant to the maximum extent practicable.

The BACT determination should, at a minimum, meet two core requirements.[1] The first core requirement is that the determination follow a "top-down" selection approach. The second core requirement is that the selection of a particular control system as BACT must be justified in terms of the statutory criteria and supported by the record and must explain the basis for the rejection of other more stringent candidate control systems.

EPD's procedures for performing a top down BACT analysis are set forth in EPA's Draft New Source Review Workshop Manual (Manual), dated October 1990. One critical step in the BACT analysis is to determine if a control option is technically feasible.[2] If a control is determined to be infeasible, it is eliminated from further consideration. The Manual applies several criteria for determining technical feasibility. The first is straightforward: if the control has been installed and operated by the type of source under review, it is demonstrated and technically feasible.

For controls not demonstrated using this straightforward approach, the Manual applies a more complex approach that involves two concepts for determining technical feasibility: availability and applicability. A technology is considered available if it can be obtained through commercial channels. An available control is applicable if it can be reasonably installed and operated on the source type under construction. A technology that is available and applicable is technically feasible.

The Manual provides some guidance for determining availability. For example, a control is generally considered available if it has reached the licensing and permitting stages of development. However, the Manual further provides that a source would not be required to experience extended time delays or resource penalties to allow research to be conducted on new technologies. In addition, the applicant is not expected to experience extended trials learning how to apply a technology on a dissimilar source type. Consequently, technologies in the pilot scale testing stages of development are not considered available for BACT.

As mentioned before, the Manual also requires available technologies to be applicable to the source type under construction before a control is considered technically feasible. For example, deployment of the control technology on the existing source with similar gas stream characteristics is generally a sufficient basis for concluding technical feasibility. However, even in this instance, the Manual would allow for an applicant to make a demonstration on the contrary. For example, an applicant could show that unresolved technical difficulties with applying a control to the source under consideration (e.g., size of the unit, location of the proposed site, and operating problems related to the specific circumstances of the source) make a control technically infeasible.

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[1] The discussion of the core requirements is taken from the Preamble to the Proposed NSR Reform, 61 FR 38272.

[2] Discussion on technical feasibility is taken from the PSD Final Determination for AES Londonberry, L.L.C., Rockingham County, New Hampshire, authored by the U.S. EPA Region I, Air Permits Program.

According to the Environmental Appeals Board (see In re: Kawaihae Cogeneration Project, 7 E.A.D. 107 at page 1996, EAB 1997), the section on "collateral environmental impacts" of a proposed technology has been interpreted to mean that "if application of a control system results directly in the release (or removal) of pollutants that are not currently regulated under the Act, the net environmental impact of such emissions is eligible for consideration in making the BACT determination." The Appeals Board continues, "The Administration has explained that the primary purpose of the collateral impacts clause is… to temper the stringency of the technological requirements whenever one or more of the specified collateral impacts – energy, environmental, or economic – renders the use of the most effective technology inappropriate." Lastly, the Appeals Board states, "Unless it is demonstrated to the satisfaction of the permit issuer that such unusual circumstances exist, then the permit applicant must use the most effective technology."

The five steps of a top-down BACT review procedure identified by EPA per BACT guidelines are listed below:

Step 1: Identification of all control technologies;
Step 2: Elimination of technically infeasible options;
Step 3: Ranking of remaining control technologies by control effectiveness;
Step 4: Evaluation of the most effective controls and documentation of results; and
Step 5: Selection of BACT.

The following is a discussion of the applicable federal rules and regulations pertaining to the equipment that is the subject of this preliminary determination, which is then followed by the top-down BACT analysis.

New Source Performance Standards

Federal Rule – 40 CFR 60 Subpart A

40 CFR 60 Subpart A, "*General Provisions*," imposes generally applicable provisions for initial notifications, initial compliance testing, monitoring, and recordkeeping requirements. Since the AFPI will be subject to a New Source Performance Standard, by extension, it is also subject to Subpart A.

Federal Rule – 40 CFR 60 Subpart Db

40 CFR 60 Subpart Db, "*Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units*," provides standards of performance for steam generators and steam generating units for which construction commenced after June 19, 1984. The AFPI is considered a steam-generating unit as defined in 40 CFR 60.40b and is subject to the PM and NO_X emission standards within. SO_2 emissions are limited to 0.20 lb/MMBtu per 40 CFR 60.42b(k), and PM emissions are limited to 0.03 lb/MMBtu per 40 CFR 60.43b(h)(1). The opacity is limited to 20 percent opacity, except for one 6-minute period of hour of not more than 27 percent per 40 CFR 60.43b(f). The NO_X emissions are limited to 0.20 lb/MMBtu, unless the facility has an annual capacity factor for natural gas of 10% or less per 40 CFR 60.44b(l)(1). Per 40 CFR 60.40b(j), the AFPI will not be subject to the requirements of 40 CFR 60 Subpart D – "*Standards of Performance for Fossil-Fuel-Fired Steam Generators*."

National Emissions Standards For Hazardous Air Pollutants

Federal Rule – 40 CFR 61 Subparts A & E

40 CFR 61 Subpart E, *Emission Standard for Mercury*, and the associated *General Provisions* of 40 CFR 61 Subpart A, do not apply to the AFPI at the facility. The facility will not be burning any wastewater treatment plant sludge in the AFPI.

Federal Rule – 40 CFR 63 Subpart DDDDD

40 CFR 63 Subpart DDDDD, "*National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters,"* regulates HAP emissions from solid, liquid, and gaseous fuel fired boilers and indirect process heaters that are located at the facility that are major sources of HAPs. The AFPI, and the existing Nebraska and York Shipley Boilers (Source Codes: VP01, JC01, and JC03) appear to be subject to this regulation. However, Visy Paper is accepting a site-wide HAP limit of 10 tons of any single HAP or any combination of HAP in an amount equal to or exceeding 25 tons during any consecutive twelve-month period in order to avoid applicability to the Boiler MACT. Likewise, the facility will not be subject to 40 CFR 63 Subpart A, "*General Provisions.*"

State and Federal – Startup and Shutdown and Excess Emissions

Excess emission provisions for startup, shutdown, and malfunction are provided in Georgia Rule 391-3-1-.02(2)(a)7. Excess emissions from the AFPI associated with the proposed project would most likely results from a malfunction of the associated control equipment. The facility cannot anticipate or predict malfunctions. However, the facility is required to minimize emissions during periods of startup, shutdown, and malfunction.

Federal Rule – 40 CFR 64 – Compliance Assurance Monitoring

Under 40 CFR 64, the *Compliance Assurance Monitoring* (CAM) Regulations, facilities are required to prepare and submit monitoring plans for certain emission units with the Title V application. The CAM Plans provide an on-going and reasonable assurance of compliance with emission limits. Under the general applicability criteria, this regulation applies to units that use a control device to achieve compliance with an emission limit and whose pre-controlled emissions levels exceed the major source thresholds under the Title V permitting program. Although other units may potentially be subject to CAM upon renewal of the Title V operating permit, such units are not being modified under the proposed project and need not be considered for CAM applicability at this time. Therefore, this applicability evaluation only addresses the AFPI, which will employ NOx reduction technology to abate NOx emissions, injected lime or sodium bicarbonate slurry to abate HCl and SO_2 emissions, and a baghouse to abate particulate emissions. Because Visy is proposing to utilize continuous emissions and opacity monitors (CEMs and COMs), applicability to the Compliance Assurance Monitoring provisions of 40 CFR Part 64 is not triggered.

4.0 CONTROL TECHNOLOGY REVIEW

The proposed project will result in increased emissions of a number of pollutants, including PM, VOC, NOx, and HAPs. However, only the increased emissions for NO_X are significant enough to trigger non-attainment New Source Review.

New Equipment - Background

The AFPI (Source Code PI01) consists of an alternative fuels bubbling fluidized bed gasifier, a turbine generator, fuel handling systems, and other equipment. The gasifier will have a nominal heat input rate of 380 MMBtu/hour, and the turbine generator will be able to co-generate approximately 8 MW of electricity. For fuel, the facility will use natural gas (startup and flame stabilization only), paper sludge, heavy rejects, dry scrap construction wood, tire derived fuel, and carpet remnants. The AFPI will be manufactured and installed in 2008. Primary emissions from the AFPI are NOx, SO_2, HCl, and Particulate Matter. The AFPI will employ several control technologies to reduce air emissions, including a NOx reduction system, either selective non-catalytic reduction or selective catalytic reduction, for abatement of NOx, injected lime or sodium bicarbonate slurry for abatement of SO_2 and HCl and other acid mists, and a baghouse for reduction of PM emissions.

Because only NOx emissions increases from the AFPI have triggered NSR applicability, only NOx emissions were evaluated for Best Available Control Technology (BACT). The increases in VOC and PM emissions from the AFPI that will result from the proposed modification do not exceed the corresponding Non-Attainment NSR and PSD significant modification thresholds; therefore VOC and PM emissions from the AFPI were not evaluated for BACT-level controls.

Although non-attainment New Source Review is being triggered due to the increase in NOx emissions from the installation of the new AFPI, the control technology standard for Best Available Control Technology (BACT) is being employed in lieu of the standard for the Lowest Achievable Emission Rate (LAER). This is because the facility is requesting a site-wide NOx emissions limit of 100 tons per year. Pursuant to Georgia Rule 391-3-1-.03(8)(c)13(iii) and the Clean Air Amendments of 1990, sources of NOx with potential NOx emissions less than 100 tons per year and located within ozone non-attainment areas are subject to BACT-level controls rather than LAER-level controls when non-attainment NSR is triggered.

AFPI Gasifier – NOx Emissions

Best Available Control Technology (BACT) is defined as the maximum degree of reduction for each pollutant, which the permitting authority determines to be achievable, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs. The U.S. EPA has recommended a “top-down” approach in determining BACT to ensure that available control technologies that are more stringent than those required by New Source Performance Standards (NSPS) are examined. The top-down BACT review approach follows a 5-step process that includes:

1. Identification of available control technologies or techniques;
2. Elimination of technologically infeasible options;
3. Ranking of the remaining control technologies;
4. Evaluation of the remaining control technologies; and
5. Selection of the control technology that constitutes BACT.

Step 1: Identification of All Control Technologies

Visy Paper identified potentially applicable NOx control technologies based on a review of information contained in US EPA's RACT/BACT/LAER Clearinghouse, information published in technical journals and trade literature, information provided by prospective control technology vendors, and experience in conducting control technology reviews for similar types of equipment. Taking into account the physical and operational characteristics of the proposed bubbling fluidized bed boiler of the AFPI, the candidate control options are listed below:

Option 1: Selective Catalytic Reduction (SCR) at varying efficiencies
Option 2: Selective Non-Catalytic Reduction (at 60 percent efficiency)
Option 3: Combustion Control Techniques

Selective Catalytic Reduction (SCR)
The selective catalytic reduction (SCR) process is based on the chemical reduction of the NOx molecule. SCR uses a catalyst to aide in the reduction reaction between a nitrogen-based reducing agent, such as ammonia or urea, and NOx in the post-combustion flue gas. The reducing agent reacts selectively with the flue gas NOx within a specific temperature range and in the presence of the catalyst and oxygen to reduce the NOx molecules into diatomic nitrogen (N2) and water vapor (H2O) according to the following chemical reaction equations:

$$4NO + 4NH_3 + O_2 \rightarrow 4N_2 + 6H_2O$$

and

$$2NO_2 + 4NH_3 + O_2 \rightarrow 3N_2 + 6H_2O$$

The reaction temperature is a function of the type of catalyst used and typically falls in the range of 390 °F to 750 °F. The catalyst utilized in the reduction reaction is a complex mixture of various active metal oxides supported on either a ceramic or metallic substrate. Historically, the most widely used catalyst has been vanadium pentoxide (V_2O_5). Other catalysts used in SCR include tungsten trioxide (WO_3) and molybdenum trioxide (MoO_3). These metal oxides are typically supported on catalyst substrates composed of ceramic components such as titanium dioxide (TiO_2) or aluminosilicates or various types of ceramic-coated steel substrates. More recently developed SCR catalysts use platinum or other noble metals supported on a metal substrate.

The amount of NOx reduction achievable through SCR is determined by the combination of several major design factors, including the ratio of ammonia or urea to NOx, the space velocity, the temperature of the gas stream being treated, the catalyst activity, and the concentration of NOx in the gas stream. As the aforementioned reaction chemistry indicates, NOx reduction is directly proportional to the amount of ammonia or urea injected into the flue gas. Reductions in NOx in the range of 60 to 90 percent are typical of SCR applications, and the reduction efficiency tends to increase as the amount of ammonia or urea injected into the gas stream increases. However, above about 80 percent NOx reduction, increased amounts of ammonia or urea injection typically do not result in equivalent increases in NOx reduction. Instead, some of the excess reagent decomposes , some forms NOx, and some exits un-reacted in a phenomenon known as "ammonia slip." Minimization of ammonia slip is an important design and operational parameter. Excess ammonia exiting the SCR reactor can react with any SO3 present (if sulfur-containing fuels are being burned) to produce ammonium bisulfate (NH4HSO4), a sticky, semisolid condensate that can corrode metal surfaces upon which it condenses and can, if present in sufficient concentration, contribute to the flue gases having a bluish-white haze. Even if the fuels do not contain sulfur, high levels of ammonia slip are still undesirable as emissions in the flue gas because once released to the atmosphere, ammonia will react to form NOx or nitrates and fine particulate matter.

Space velocity is the ratio of the volume or the flue gas being treated per hour divided by the volume of catalyst present. As in any catalyst-based reaction, the efficiency of the reaction is related to the quantity and available surface area of the catalyst present. The quantity of catalyst employed in SCR reactors is a design tradeoff; While increased NOx reduction occurs with the use of larger quantities of catalyst, costs for the catalyst are higher and flue gas pressure drop across the SCR reactor is increased.

Reaction temperature is important for several reasons. Higher temperatures can lead to increased NOx removal. However, higher than desired operating temperatures can shorten the catalyst life or oxidize the injected ammonia to produce more NOx rather than reduce it. Moreover, as the catalyst ages, it tends to lose potency; thereby required gradual increases in operating temperature and/or ammonia injection to maintain NOx removal performance at desired levels.

The SCR system typically consists of a reagent storage and preparation system, injection of the reagent into the flue gas stream through an injection grid mounted in the ductwork, and a reactor chamber containing the catalyst. Additional mixers ahead of the reactor chamber may be used to increase mixing or the flue gas stream and reagent. SCR systems can be located in several post-combustion locations. Flue gas temperatures and constituents vary with the location of the SCR reactor chamber. SCR reactors located upstream of the particulate control device and air heater will have higher temperatures, but will also have higher levels of particulate matter (high-dust SCR). SCR reactors located downstream of the particulate matter control device and air heater will have lower levels of particulate matter (low-dust SCR), but will also have lower flue gas temperatures and may require re-heating of the flue gas.

Catalyst activity, both initial and over time, is a function of the concentration and distribution of the catalytically active metals in the catalyst and the physical characteristics of the substrate, especially available surface area. Over time, components in the flue gas can deposit on the catalyst and irreversibly react with the catalytically active metals, thereby decreasing NOx reduction efficiency. Moreover, prolonged exposure to high temperatures or rapid cycling between high and low temperatures can damage the underlying catalyst substrate, thereby reducing access of the NOx in the flue gas to the catalyst surface and again decreasing NOx reduction efficiency. Proper design and operation of the SCR systems must consider the longevity of the catalyst and the factors that may cause the catalyst to lose its catalytic activity.

The use of the catalyst provides two significant advantages over the Selective Non-Catalytic Reduction (SNCR) technology: a higher potential NOx reduction efficiency (typically between 70 and 90 percent) is achievable, and the reaction can occur over a lower and broader temperature range. The main disadvantages of SCR are: the higher capital and operating costs, and the catalyst must be periodically replaced due to thermal sintering, poisoning, fouling, and aging. The gradual or abrupt decline in catalyst activity can result in fluctuations in NOx reduction efficiency before the catalyst is replaced.

Loss of catalyst activity and the corresponding frequency of catalyst replacement are critical considerations when evaluating the application of an SCR system for a bubbling fluidized bed boiler. The composition and nature of the fuels combusted in, and of the exhaust gases produced by, a bubbling fluidized bed boiler are such that SCR catalyst can be poisoned or fouled in a relatively short period of time, without indication of decreasing activity. If the catalyst cannot be regenerated, it must be disposed of as a hazardous waste.

Selective Non-Catalytic Reduction (SNCR)
Both SCR and SNCR rely on the reaction of a nitrogen-based reducing reagent such as ammonia or urea with NOx in the flue gas to reduce the NOx into diatomic nitrogen and water vapor. With SNCR the reaction takes place in the post-combustion flue gas in the mid to upper area of the boiler without the presence of a catalyst. The heat of the boiler provides the energy for the reduction reaction. Because a catalyst is not involved, SNCR generally has a lower potential NOx reduction efficiency and a higher range of acceptable operating temperatures (1,600 °F to 2,000 °F) when compared to SCR. The effective temperature range can be widened with the addition of gases and/or additives. As a stand-alone technology, SNCR has achieved NOx reduction efficiencies between 40 and 60 percent in industrial boiler applications. SNCR systems share many of the important design and operation factors that can affect the performance of an SCR system, including: reagent to NOx ratio, residence time, temperature, degree of mixing between the injected reagent and the combustion gases, and the concentration of NOx in the flue gas.

For a bubbling fluidized bed boiler, the temperature profile above the overfire air and before the superheater inlet is compatible with the optimum temperature range for an SNCR system. This area also should provide sufficient residence time and turbulence for mixing. Multiple levels of reagent injectors are usually installed, with only a single level required to operate in order to inject the ammonia into the furnace at the appropriate gas temperature window. As the combustion zone temperature varies with load and fuels, reagent flow and injection zone is varied based on feedback from temperature sensors and a NOx continuous emissions monitor (CEM). SNCR is technologically feasible and is considered an appropriate NOx control technology for the proposed bubbling fluidized bed boiler.

Controlled Combustion Techniques
There are three major mechanisms for NOx formation in the combustion process. The thermal NOx formation mechanism involves thermal dissociation and subsequent reaction of nitrogen and oxygen molecules in combustion air. The fuel NOx formation mechanism is based on oxidation of fuel-bound nitrogen contained in certain fuels. Of considerably less significance is the prompt NOx formation mechanism of reacting molecular nitrogen with hydrocarbon radicals. Of these three routes, thermal NOx formation is widely recognized as the most significant and controllable mechanism in an industrial boiler application.

The extent of thermal NOx formation depends on combustion characteristics, such as oxygen and nitrogen concentrations in the flame zone, temperature, and residence time. The peak, or maximum, flame temperature is the most important parameter that determines the potential for thermal NOx formation. At high temperatures, usually above 2,200 °F, diatomic nitrogen and oxygen molecules in the combustion gas stream dissociate into their atomic states and participate in a series of reactions producing thermal NOx. In a bubbling fluidized bed boiler, the high turbulence and enhanced mixing enables the bubbling bed to maintain an optimum combustion environment at fairly moderate combustion zone temperatures. The lower combustion zone temperatures limit the formation of thermal NOx to negligible levels.

Bubbling fluidized bed technology incorporates a hot fluidized bed of inert material operating in a reduced oxygen atmosphere and at a low temperature (around 1,290 °F) to gasify the solid fuel. Combustion of the gases produced is then completed by injection of secondary air in the freeboard area above the bed, where the temperature will be above 1,560 °F with a residence time in excess of 2 seconds before the products of combustion leave the furnace. The combination of a reduced oxygen atmosphere in the bed and staged combustion will minimize thermal NOx production.

Step 2: Elimination of Technically Infeasible Options

None of the aforementioned control technologies is considered technically infeasible, although frequent and unanticipated poisoning of the catalyst of an SCR system could be an issue for the proposed bubbling fluidized bed boiler due to the nature and types of fuels that will be utilized. Each of the aforementioned control technologies is evaluated and ranked in the sections that follow.

Step 3: Ranking of the Remaining Control Technologies by Control Effectiveness

The aforementioned, technically feasible control technologies are presented in Table 4-1 below, ranked in descending order according to NOx control efficiency. Because varying levels of NOx reduction are possible through manipulation of the design parameters of SCR systems, SCR is listed five times with a range of overall reduction efficiencies. Furthermore, because combustion control techniques, such as reduced oxygen atmosphere and staged combustion, are so cost-effective and are essentially inherent in the design of bubbling fluidized bed boilers, both SCR and SNCR control technologies are presented in combination with such combustion control techniques.

Table 4-1: Ranking of Control Technology

Ranking	Description of Control Technology	Control Efficiency	Annualized NOx Emission Rate (tpy)
1	Combination of Combustion Control Techniques and SCR	80%	87.0
2	Combination of Combustion Control Techniques and SCR	73%	117
3	Combination of Combustion Control Techniques and SCR	69%	134
4	Combination of Combustion Control Techniques and SCR	65%	151
5	Combination of Combustion Control Techniques and SCR	60%	173
6	Combination of Combustion Control Techniques and SNCR	60%	173

Step 4: Evaluation of the Most Effective Controls and Documentation

A review of possible control technologies and recently issued construction permits with NOx emission limits for similar operations was conducted using US EPA's RACT/BACT/LAER Clearinghouse and other sources. A comparison of NOx controls required for similar, recently installed equipment is presented below in Table 4-2. Recent determinations issued by GA EPD are indicated in bold typeface.

Table 4-2: Comparison of NOx Controls for Similar, Recently Installed Equipment

	Facility	State	Year	Equipment	Maximum Heat Input (MMBtu/hr)	NOx Limit (lb/MMBtu)	Regulation	Control Technology
1	**Trigen Biopower**	**GA**	**1998**	**Multi-fuel[1] Bubbling Fluidized Bed Boiler**	**265**	**0.25 30-day ave.**	**PSD/BACT**	**Combustion Control Techniques**
2	Grayling Generating Station	MI	2001	Multi-fuel[2] Stoker Boiler	500	0.156	PSD/BACT	SNCR (urea)
3	McCartin Group Energy Services of Manitowa	WI	2001	Circulating Fluidized Bed Boiler	338	0.07	PSD/BACT	SNCR 46% Efficiency
4	TES Filer City Station	MI	2001	Multi-fuel[3] Stoker Boiler	384	0.60 30-day ave.	NSPS Da	SCR, Combustion Control Techniques
5	Fibromin Biomass Power Plant	MN	2002	Multi-fuel[4] boiler	792	0.16 30-day ave.	PSD/BACT	SNCR 50% Efficiency
6	**Interstate Paper**	**GA**	**2002**	**Multi-fuel[5] Bubbling Fluidized Bed Boiler**	**300**	**0.25 30-day ave.**	**PSD/BACT**	**Combustion Control Techniques**
7	Georgia Pacific-Monticello Mill	MS	2003	Multi-fuel[6] Stoker Boiler	917	0.31	PSD/BACT	Low NOx Burners, Over-Fired Air, Good Combustion Techniques

1: Fuel consists of biomass.
2: Fuels consist of wood and tire-derived fuel (TDF).
3: Fuels consist of coal, tire-derived fuel and (TDF), and wood.
4: Fuels consist of wood, manure, wood waste, and bagasse.
5: Fuels include wood waste and tire-derived fuel (TDF).
6: Fuels include wood, sludge, and tire-derived fuel (TDF).

Recent BACT determinations for equivalent emission units include those for multi-fuel bubbling fluidized bed boilers at Trigen Biopower and Interstate Paper in 1998 and 2002, respectively. Both facilities are located in Georgia, and the BACT determinations were issued by GA EPD. In each case, BACT was determined to be design standards, such as over-fired air, and good combustion techniques. Each facility was limited to a NOx emissions rate of 0.25 pounds of NOx per MM Btu of fuel combusted, as averaged over a rolling 30-day period. The lowest NOx emission rate resulting from a BACT determination for similar equipment was issued to the McMartin Group Energy Services of Manitowa (MGES) by the Wisconsin DNR; that BACT determination for a circulating fluidized bed boiler limits MGES to 0.07 pounds NOx per MM Btu and requires abatement with an SNCR system operating at an overall NOx reduction efficiency of 46 percent.

An economic analysis was performed on the control technology options identified by Visy Paper, including review of total annualized costs and the average and incremental cost effectiveness of each control technology. The results are presented below in Table 4-3.

Table 4-3: Economic Analysis of Control Options

	Control Technology	NOx Emissions* (tpy)	NOx Emissions lb/MMBtu	Total Annualized Costs ($/year)	Average Cost Effectiveness ($/ton)	Incremental Cost Effectiveness ($/ton)
1	Combination of Combustion Control Techniques and SCR at 80% Reduction Efficiency	87	0.05	1,949,000	5,626	2,738
2	Combination of Combustion Control Techniques and SCR at 73% Reduction Efficiency	117	0.07	1,866,000	5,903	2,714
3	Combination of Combustion Control Techniques and SCR at 69% Reduction Efficiency	134	0.08	1,819,000	6,088	2,714
4	Combination of Combustion Control Techniques and SCR at 65% Reduction Efficiency	152	0.09	1,772,000	6,296	63,857
5	Combination of Combustion Control Techniques and SNCR at 60% Reduction Efficiency	174*	0.10	431,000	1,664	N/A

*NOx emissions based on maximum annual potential NOx emissions of 433 tons per year.

The economic analysis of the identified control technology options consists of evaluation of the total annualized costs and average effectiveness costs of each control technology, as well as the incremental cost effectiveness of each option over the next most effective control technology. The total annualized cost estimate presents the sum of the predicted capital and operating costs over a standard 10-year period at the prevailing interest rate and indicates the absolute cost of each identified control system. The average and incremental cost effectiveness figures are expressed in terms of dollars per ton of NOx emissions reduced; the average cost effectiveness is simply the total annualized costs divided by the total annual tons of NOx that would be removed by the respective control technology, while the incremental cost effectiveness compares the difference in two control technologies divided by the corresponding difference in their control efficiencies.

The company has proposed SCR NOx reduction technology at a reduction efficiency of 73 percent and emission rate of 0.07 lb/MM Btu as BACT. SCR at greater reduction efficiencies (i.e., 80 percent reduction and 0.05 lb/MM Btu) was rejected as BACT based on 1) increase in ammonia slip, 2) lack of margin of compliance, and 3) 0.07 lb/MM Btu was toughest emission limit identified on any similar source.

Step 5: Selection of BACT

After review of relevant control technologies and careful consideration of their associated economic and environmental benefits and costs, the Division has determined that Selective Catalytic Reduction (SCR) operating at an overall NOx reduction efficiency of 73 percent in combination with good combustion techniques, or similar technology achieving an equivalent or greater NOx reduction efficiency, as proposed by the applicant, constitutes BACT for the proposed project. The equivalent NOx emission rate for application of these control techniques is determined to be 0.07 pounds of NOx per million Btu of fuel combusted at the boiler's maximum operating heat input capacity, as averaged over a rolling 30-day basis.

Conclusion – NOx Control

The Division has determined that Visy Paper's proposal to use selective a NOx reduction system, consisting of non-catalytic reduction (SNCR) and/or selective catalytic reduction (SCR), to minimize the emissions of NOx from the AFPI's gasifier unit to a rate not to exceed 0.07 pounds per million BTU, as averaged on a rolling 30-day basis, constitutes BACT. As proposed by the applicant, compliance will be monitored through the use of continuous emissions monitors for NOx.

Summary – NOx Control Technology Review for the AFPI

To fulfill the Non-Attainment NSR permitting requirements for NOx, a BACT analysis was conducted for the modified gasifier unit of the proposed AFPI. The BACT selection for the gasifier is summarized below in Table 4-2:

Table 4-2: BACT Summary for the Proposed AFPI Gasifier

Pollutant	Control Technology	Proposed BACT Limit
NOx	Combination of Combustion Control Techniques and a NOx reduction system (SNCR or SCR)	0.07 lbs NOx/MMBtu as averaged on a rolling 30 day basis

5.0 TESTING AND MONITORING REQUIREMENTS

Monitoring Requirements:

The Alternative Fuels Power Island (AFPI) will be equipped with continuous emissions monitors (CEMs) for NOx and SO_2 emissions. The CEMs will be installed and operated according to manufacturers' specifications and are subject to Procedure 1 (Appendix F) of the Division's *Procedures for Testing and Monitoring Sources of Air Pollutants* and 40 CFR Part 60. Pollutant concentrations will be measured and recorded at a minimum frequency of once every 15 minutes, and the values for each 30-consecutive day period will be averaged in to determine in the AFPI is operating within the NOx and SO_2 limits incorporated into the proposed permit amendment.

CAM Applicability:

Because Visy is proposing to utilize continuous emissions and opacity monitors (CEMs and COMs), applicability to the Compliance Assurance Monitoring provisions of 40 CFR Part 64 is not triggered. .

6.0 AMBIENT AIR QUALITY REVIEW

Under the provisions of 40 CFR 51.165, offsetting emission reduction credits must be procured by the source prior to commencing operation in lieu of performing an ambient air quality analysis (only applicable for VOC or NO_X emissions). The purpose of the emission offset credits is to ensure that the sum total of the emissions of the non-attainment pollutant, including the emissions from the proposed modification, as less than the sum total of the non-attainment pollutant emissions before the proposed modification beings operation, so as to represent (when considered together with other air pollution control measures legally enforced in such areas or regions) reasonable further progress towards attaining the National Ambient Air Quality Standard (NAAQS) for which the area is in non-attainment.

The US EPA has established ratios relating the amount of emission offset credits that must be obtained to the amount of allowable non-attainment pollutant emissions from a major source or modification for the five non-attainment area classifications. The classifications and ratios correspond as follows: marginal (1.1:1), moderate (1.15:1), serious (1.2:1), severe (1.3:1), and extreme (1.5:1). Rockdale County, in which the Visy Paper facility is situated, is located within the former 13-county Atlanta Non-Attainment Area, which was classified as a severe ozone non-attainment area under the 1-hour ozone National Ambient Air Quality Standard (NAAQS). Although that area has since attained compliance with the former 1-hour ozone standard, it is now part of a larger 20-county ozone non-attainment area, classified as marginal under the new 8-hour ozone NAAQS. Furthermore, the area remains under a maintenance plan for the former 1-hour ozone non-attainment classification. Consequently, the former 25 ton per year major source threshold, 25 ton increase over 5 consecutive year de minimis non-attainment New Source Review applicability trigger, and 1.3 to 1 offset ratio still remain in effect. Therefore, Visy Paper must obtain 1.3 tons of offsets for every ton of increased NOx emissions from the AFPI.

Taking into account the new site-wide annual NOx emissions limit of 100 tpy and subtracting the projected actual emissions of existing NOx-emitting sources, the maximum actual NOx emissions from the AFPI cannot exceed 55 tons per year, after controls. Therefore, at the 1.3:1 offset ration, 71.5 tons of offsets must be obtained. Visy Paper is proposing to obtain 18.5 tons of reductions internally through a voluntary cap on NOx emissions from the existing Nebraska Boiler of 4 tons per year. The remaining 53 tons of NOx offsets will be obtained from a third party that has banked NOx offsets in the Division's Emission Reduction Credit program; Visy Paper has entered into a binding agreement with this ECR holder for the purchase of the necessary NOx emission credits.

Because the 1.3 to 1 offset ratio of non-attainment New Source Review results in a net decrease in NOx emissions in the emissions inventory of the affected non-attainment area, no further ambient air quality review is required.

7.0 ADDITIONAL IMPACT ANALYSES

Non-attainment New Source Review requires an analysis of impairment to visibility, soils, and vegetation that will occur as a result of the emissions from the proposed project and an analysis of the air quality impact projected for the area as a result of the general commercial, residential, and other growth associated with the proposed project. Other impact analysis requirements may also be imposed on a permit applicant under local, State, or Federal laws which are outside the NSR Permitting Program, such as Georgia's Toxic Guidelines.

Soils and Vegetation

No sensitive soil types are known to existing within the area of the project. Moreover, the areas of maximum impact are generally cultivated or forested and demonstrate no obvious sensitivity to industrial air emissions. Therefore, no negative impacts on soils and vegetation are anticipated to result from the implementation of the proposed project.

Growth

The purpose of a growth analysis is to predict how much new growth is likely to occur as a result of the project and the resulting air quality impacts from this growth. No adverse impacts on growth are anticipated from the project since any workforce growth and associated residential and commercial growth that would be associated with the proposed project (expected to be minimal) would not cause a quantifiable impact on the air quality of the area surrounding the facility.

Visibility

Visibility impairment is any perceptible change in visibility (visual range, contrast, atmospheric color, etc.) from that which would have existed under natural conditions. Poor visibility is caused when fine solid or liquid particles, usually in the form of volatile organics, nitrogen oxides, or sulfur oxides, absorb or scatter light. This light scattering or absorption actually reduces the amount of light received from viewed objects and scatters ambient light in the line of sight. This scattered ambient light appears as haze.

Another form of visibility impairment in the form of plume blight occurs when particles and light-absorbing gases are confined to a single elevated haze layer or coherent plume. Plume blight, a white, gray, or brown plume clearly visible against a background sky or other dark object, usually can be traced to a single source such as a smoke stack.

Georgia's SIP and Georgia Rules for Air Quality Control provide no specific prohibitions against visibility impairment other than regulations limiting source opacity and protecting visibility at federally protected Class I areas. To otherwise demonstrate that visibility impairment will not result from continued operation of the mill, the VISCREEN model was used to assess potential impacts on ambient visibility at so-called "sensitive receptors" within the SIA of the Visy Paper facility. There are five Class I areas within 300 km of the facility, the nearest of which is the Cohutta Wilderness Area. Since there is no ambient visibility protection standard for Class II areas, this analysis is presented for informational purposes only and predicted impacts in excess of screening criteria are not considered "adverse impacts" nor cause further refined analyses to be conducted.

The primary variables that affect whether a plume is visible or not at a certain location are (1) quantity of emissions, (2) types of emissions, (3) relative location of source and observer, and (4) the background visibility range. For this exhaust plume visibility analysis, a Level-1 visibility analysis was performed using the latest version of the EPA VISCREEN model according to the guidelines published in the Workbook for Plume Visual Impact Screening and Analysis (EPA-450/4-88-015). The VISCREEN model is designed specifically to determine whether a plume from a facility may be visible from a given vantage point. VISCREEN performs visibility calculations for two assumed plume- viewing backgrounds (horizon sky and a dark terrain object). The model assumes that the terrain object is perfectly black and located adjacent to the plume on the side of the centerline opposite the observer.

In the visibility analysis, the total project NOx and PM10 emissions increases were modeled using the VISCREEN plume visibility model to determine the impacts. For both views inside and outside the Class II area, calculations are performed by the model for the two assumed plume-viewing backgrounds. The VISCREEN model output shows separate tables for inside and outside the Class II area. Each table contains several variables: theta, azi, distance, alpha, critical and actual plume delta E, and critical and actual plume contrast. These variables are defined as:

1. Theta – Scattering angle (the angle between direction solar radiation and the line of sight). If the observer is looking directly at the sun, theta equals zero degrees. If the observer is looking away from the sun, theta equals 180 degrees.

2. Azi – The azimuthal angle between the line connecting the observer and the line of sight.

3. Alpha – The vertical angle between the line of sight and the plume centerline.

4. delta E – Used to characterize the perceptibility of a plume on the basis of the color difference between the plume and a viewing background. A delta E of less than 2.0 signifies that the plume is not perceptible.

5. Contrast – The contrast at a given wavelength of two colored objects such as plume/sky or plume/terrain.

The analysis is generally considered satisfactory if delta E and Contrast are less than critical values of 2.0 and 0.05, respectively, both of which are Class I, not Class II, area thresholds. The Division has reviewed the VISCREEN results presented in the permit application and have determined that the visual impact criteria (delta E and Contrast) at the affected sensitive receptors are not exceeded as a result of the proposed project. Since the project passes the Level-1 analysis for a Class I area, no further analysis of exhaust plume visibility is required as part of this air quality analysis.

Georgia Toxic Air Pollutant Modeling Analysis

Georgia EPD regulates the emissions of toxic air pollutant (TAP) emissions through a program covered by the provisions of *Georgia Rules for Air Quality Control*, 391-3-1-.02(2)(a)3.(ii). A TAP is defined as any substance that may have an adverse effect on public health, excluding any specific substance that is covered by a State or Federal ambient air quality standard. Procedures governing the Georgia EPD's review of TAP emissions as part of air permit reviews are contained in the agency's "*Guideline for Ambient Impact Assessment of Toxic Air Pollutant Emissions (Revised)*." The *Guideline* implies that a pollutant is identified as a toxic air pollutant if any of the following toxicity determined values have been established for that pollutant:

- U.S. EPA Integrated Risk Information System (IRIS) reference concentration (RfC) or unit risk
- Occupational Safety and Health Administration (OSHA) Permissible Exposure Limits (PEL)
- American Conference of Governmental Industrial Hygienists (ACGIH) Threshold Limit Values (TLV)
- National Institute for Occupational Safety and Health (NIOSH) Recommended Exposure Limits (REL)
- Lethal Dose –50% (LD_{50}) Standards

Selection of Toxic Air Pollutants (TAP) for Modeling

For projects with quantifiable increases in TAP emissions, an air dispersion modeling analysis is generally performed to demonstrate that off-property impacts are less than the established Acceptable Ambient Concentration (AAC) values. The TAPs evaluated are restricted to those that may increase due to the proposed project. Thus, the TAP analysis would generally be an assessment of off-property impacts due to facility-wide emissions of any TAP emitted by a facility. To conduct a facility-wide TAP impact evaluation for any pollutant that could conceivably be emitted by the facility is impractical. A literature review would suggest that at least one molecule of hundreds of organic and inorganic chemical compounds could be emitted from the various combustion units. This is understandable given the complex and varying nature of the fuels, including natural gas, fuel oil, carpet waste, scrap wood, construction waste, paper sludge, heavy reject materials, and tire-derived fuel, fed to the combustion sources, and the fact that there are complex chemical reactions and combustion of fuel taking place in some. The vast majority of compounds potentially emitted however are emitted in only trace amounts that are not reasonably quantifiable.

For the purposes of the toxic impact assessment, hydrogen chloride was identified as the primary TAP of concern and was used as a surrogate for total TAP emissions. Of the TAPs expected to be emitted in quantifiable amounts from combustion sources at the facility, hydrogen chloride has relatively low exposure thresholds, including a 15-minute ceiling exposure threshold, and will be emitted in quantities exceeding those of the other quantifiable TAPs. An emission rate of 2.26 pounds per hour, or 0.2848 grams per second, was derived from the requested HCl limit of 10 tons per rolling 12-month period. Conservative design values were used for stack parameters, since the design of the stack for the AFPI has not been finalized yet. The toxic impact assessment conducted by Visy Paper is discussed in Section 6 of the permit application, and the results of the Screen 3 modeling are presented in Appendix C of the application.

Both the short-term and long-term AAC for HCl were calculated following the procedures given in Georgia EPD's *Guideline*. Figure 8-3 of Georgia EPD's *Guideline* contains a flow chart of the process for determining long-term and short-term ambient thresholds. Visy Paper referenced the resources previously detailed to determine the long-term (i.e., annual average) and short-term AACs (i.e., 24-hour or 15-minute). The AACs were verified by the EPD.

Determination of Toxic Air Pollutant Impact

The Georgia EPD *Guideline* recommends a tiered approach to model TAP impacts, beginning with screening analyses using SCREEN3, followed by refined modeling, if necessary, with ISCST3 or ISCLT3. For the refined modeling completed, the infrastructure setup for the SIA analyses was relied upon with appropriate sources added for the TAP modeling. Note that per the Georgia EPD's *Guideline*, downwash was not considered in the toxic impact assessment.

The initial screen modeling indicates that the MGLC of 0.62 ppm HCl beyond the plant boundary will be well below the AAC of 5 ppm. Therefore, no enhanced or refined modeling was required.

Project Alternatives Analysis

Pursuant to the provisions of the Georgia Rules for Air Quality Control at 391-3-1-.03(8)(c)4 and the Clean Air Act as amended in 1990, the applicant for a project that undergoes non-attainment New Source Review must include with the application an analysis of alternative sites, sizes, production processes, and environmental control techniques that demonstrates that the benefits of the proposed modification significantly outweigh the environmental and social costs. This analysis was submitted on May 25, 2006, with the revised BACT analysis.

Alternate Sites:
Pratt Industries is planning for the proposed Alternative Fuels Power Island (AFPI) to provide steam and electrical power to three existing production facilities, Visy Paper, Jet Corr/Pratt Displays, and Jet Corr II. Therefore, it is imperative that the proposed AFPI be located in close proximity to each of these three co-located sites, and it would be impractical to choose a more distant location outside of the boundaries of the current Atlanta 8-Hour Non-Attainment Area. If the AFPI were to be constructed elsewhere, then each of the existing facilities would need to be relocated as well, and the environmental and socio-economic impacts would be significantly greater than those of the proposed project. For example, if the project and existing facilities were to be relocated outside of the Atlanta Non-Attainment Area, the AFPI would not be subject to emissions standards as stringent as those it must meet in the Atlanta area such as BACT with emissions offsets.

Alternate Sizes:
The bubbling fluidized boiler (BFB) of the proposed AFPI project has been sized to meet the steam and electrical needs of the existing Visy Paper, Jet Corr/Pratt Displays, and Jet Corr II facilities. A smaller boiler would not provide sufficient steam and electrical power to one or more of these facilities. Without these critical utilities, the facilities would need to obtain utility-generated power, which would defeat the purpose of the proposed AFPI.

Alternate Production Processes:
The selection of a combustion technology is generally driven by available fuel quantities, properties of the available fuels, the energy needs of the facility, cost, and environmental issues. Historically, solid fuel combustion technology used in the pulp and paper industry has focused on stoker-fired boilers with coal, bark, and wood waste as fuels. While stoker technology has evolved from crude fuel feed and manual ash removal to automatic fuel feed and ash removal today, this evolution can be attributed to material handling improvements and to improvements in fuel quality. As the demand for higher quality fuels has increased, costs have escalated, and many facilities are looking to reduce their dependence on fuels that are in high demand. This, coupled with the goal to reduce landfill, or even reclaim previously landfilled, material has led to an increased desire to combust alternative materials, such as paper sludge, reject materials, dry scrap construction wood, tire-derived fuel, and waste carpet being proposed for this project. With this latest shift in preference for fuel sources, there has been a growing trend away from stoker technology and towards fluid bed technology.

Bubbling fluidized bed units, in which the solid material (typically sand and the solid fuel) is stationary in the bed, are particularly efficient when firing fuels with a higher volatile content and lower carbon content, such as carpet and tire-derived fuel. Circulating fluidized bed (CFB) technology, in which the solid material is circulated through the bed to a cyclone, then back to the bed, is a very flexible option for the combustion of a wider variety of fuels, generally including those with higher sulfur content such as waste coals and petroleum coke. The choice between BFB and CFB technology is largely linked to the choice of fuels. BFB is a simpler and lower-cost technology, which has been the preferred choice for biomass or similar fuels with a high volatile content. In either case, the low operating temperature of a fluidized bed combustion system results in negligible thermal NOx being generated, which is a significant environmental advantage versus stoker firing. The necessary use of materials for fluidization also results in inherently lower emission rates of SO_2 and acid gases in comparison to stoker technology.

The alternative of installing an electric boiler was also considered but rejected because it would result in similar NOx emission rates per million Btu of heat input at the generating source(s), consultations with the Georgia Power Company indicated that the local utilities could not meet the demand of such equipment, and such options would be economically infeasible for the proposed project.

Environmental Justice Considerations and Analysis

The Division has reviewed the population density, minority population and low income demographic maps provided by Region IV of the U.S. EPA. The data in these maps was obtained from the 2000 Census. A review of these maps indicates that the majority of the land surrounding the Visy Paper facility has a population density between 101 and 500 people per square mile, although there are areas with higher population densities of 5000 people per square mile. A slight correlation exists between areas with higher population density and areas with high minority and/or low income populations. However, the nearest areas with concentrated minority and/or low income populations are located in neighboring DeKalb County, more than four miles distant from the Visy Paper facility.

The proposed project will result in a net decrease in metropolitan area NOx emissions, which are precursors for ground-level ozone and fine particulate matter, and other criteria pollutants from the facility itself. Moreover, a visibility impact analysis and toxic impact analysis conducted on the proposed modification indicate that no localized significant adverse environmental impacts will occur due to decrease in visibility or exposure to toxic air pollutants. Therefore, the proposed project is deemed not to result in disproportionate environmental impact on potential neighboring environmental justice areas.

8.0 EXPLANATION OF DRAFT PERMIT CONDITIONS

The permit requirements for this proposed facility are included in draft Permit Amendment No. 2631-247-0037-V-01-1.

Section 1.0: Facility Description

Visy Paper has proposed to construct and operate an Alternative Fuels Power Island. The Alternative Fuels Power Island (AFPI) will consist of an alternative fuels bubbling fluidized bed gasifier, various air pollution control equipment, a turbine generator, fuel handling systems, and other equipment. The gasifier (Source Code: PI01) will have a nominal heat input rate of 380 MMBtu/hour, and the turbine generator will be able to co-generate approximately 8 MW of electricity. For fuel, the facility will use natural gas (startup and flame stabilization only), paper sludge, heavy rejects, dry scrap construction wood, tire derived fuel, carpet remnants, and other fuels compatible with the design of the boiler. The facility plans to install a bag filter to control PM emissions, a lime or sodium bicarbonate addition system to control HCl and SO_2 emissions, and a NOx reduction (SNCR or SCR) system to control NO_X emissions. Additionally, the facility will use continuous emissions monitors (CEMs) for monitoring NO_X, SO_2, CO, and opacity emissions.

Section 2.0: Requirements Pertaining to the Entire Facility

Existing **Condition No. 2.1.2**, which limits CO emissions from original facility, is being deleted because it is subsumed by new Condition No. 2.1.4.

New Permit **Condition No. 2.1.3** limits the enitre Part 70 site to 10 tons of any single HAP and 25 tons of all combined HAP per consecutive twelve-month period. This limit was requested by the facility in order to avoid applicability to 40 CFR 63 Subpart DDDDD.

New Permit **Condition No. 2.1.4** limits the entire Part 70 site to 100 tons of CO per consecutive twelve-month period. This limit was requested by the facility in order to avoid applicability to PSD.

New Permit **Condition No. 2.1.5** limits the entire Part 70 site to 100 tons of SO_2 per consecutive twelve-month period. This limit was requested by the facility in order to avoid applicability to PSD.

New Permit **Condition No. 2.1.6** limits the entire Part 70 site to 100 tons of NO_X per consecutive twelve-month period. This limit was requested by the facility in order to utilize BACT in lieu of LAER in the Non-Attainment Area New Source Review.

Section 3.0: Requirements for Emission Units

New Permit **Condition No. 3.2.4** limits VOC emissions from the AFPI to less than 10.8 tons during any twelve-consecutive month period. This limit was requested by the facility in order to avoid triggering NAA-NSR for VOC from the AFPI project. The VOC limit in this permit condition, in coordination with the good combustion control techniques required by Condition No. 3.2.5, also satisfies the VOC RACT requirement of GA Rule (tt).

New Permit **Condition No. 3.2.5** limits NOx emissions from the AFPI (specifically, the Bubbling Fluidized Boiler) to no more than 0.07 pounds per million Btu, as averaged over a rolling 30-day period. This limit is being imposed as a BACT determination under NAA-NSR. This Condition satisfies the requirements of NSPS Subpart Db, NOx BACT under non-attainment New Source Review, and NOx RACT under GA Rule (yy).

New Permit **Condition No. 3.2.6** imposes a new NOx emission limit of 4.0 tons per year on the existing Nebraska Boiler. This limit is being imposed at the request of the applicant in order to generate internal NOx offset emissions needed for the permitting of the new AFPI. Because an extended shakedown period of up to one year for the AFPI is anticipated, during which greater utilization of the existing Nebraska Boiler will be necessary, this limit takes effect one year from the date on which the AFPI is successfully commissioned.

New Permit **Condition No. 3.2.7** requires Visy to obtain the necessary external emission reduction credits, in the amount of 53 tons (at a 1.3:1 ratio), needed to offset the increase in NOx emissions resulting from the addition of the AFPI.

New Permit **Condition No. 3.3.2** is being added to incorporate the NSPS General Provisions for the existing Nebraska Boiler and the proposed AFPI, both of which are subject to NSPS Subpart Db.

New Permit **Condition No. 3.3.3** incorporates by reference all the applicable provisions of NSPS Subpart Db for the Bubbling Fluidized Bed Boiler of the AFPI.

New Permit **Condition No. 3.3.4** limits particulate matter emissions from the AFPI to no more than 0.03 pounds per million Btu heat input, pursuant to NSPS Subpart Db.

New Permit **Condition No. 3.3.5** limits visible emissions from the AFPI to no more than 20 percent opacity, as based on a six-minute average, except for one six-minute period per hour during which the opacity shall not exceed 27 percent. These opacity limits are being imposed pursuant to NSPS Subpart Db.

New Permit **Condition No. 3.3.6** limits sulfur dioxide emissions from the AFPI to no more than 0.20 pounds per million Btu heat input, as averaged over a rolling 30-day period, pursuant to NSPS Subpart Db.

New Permit **Condition No. 3.4.5** limits the sulfur content of all fuels burned in the AFPI to no more than three percent, by weight, at all times that the lime/sodium bicarbonate SO_2 abatement system is not operating. As with Condition No. 3.4.5, the regulatory basis for this limit is State Rule (g).

New Permit **Condition No. 3.5.1** is a standard best management practices condition for sources with baghouses requiring that an inventory of replacement filter bags be maintained on site so that interruptions in the control efficiency of the baghouse of the AFPI can be avoided.

<u>Section 4.0: Requirements for Testing</u>

Five additional reference test methods are being added to existing Condition No. 4.1.3 for measurement of VOCs, SO_2, PM, HAPs, and hydrogen chloride emissions. In addition, the reference test method for fuel oil sulfur content is revised to reflect the current citation of the Procedures for Testing and Monitoring.

Pursuant to NSPS Subpart Db, specific performance testing requirements for emissions of particulate matter, sulfur dioxide and nitrogen oxides are incorporated in this amendment.

New **Permit Condition Nos. 4.2.3 and 4.2.4** require initial and annually recurring performance tests for particulate matter emissions to establish the excursion reporting threshold of Condition No. 6.1.7.c.

New **Permit Condition No. 4.2.5** requires an initial performance test for emissions of sulfur dioxide, using the continuous emissions monitor.

New **Permit Condition Nos. 4.2.6 and 4.2.7** require an initial nitrogen oxides performance test, using the continuous emissions monitor, and define the term "steam generating unit operating day" as it pertains to the AFPI.

New **Permit Condition No. 4.2.8** requires an initial performance test of the AFPI within 120 days of the date it is successfully commissioned in order to confirm the control efficiency of the lime/sodium bicarbonate injection system and to establish an emission factor for HCl emissions.

Section 5.0: Requirements for Monitoring

New Permit **Condition No. 5.2.6** is being added to require the installation and use of continuous emissions monitors on the AFPI for monitoring of NOx, CO, and SO_2 emissions, and a continuous opacity monitor for the monitoring of visible emissions.

New Permit **Condition No. 5.2.7** specifies the minimum required data collection frequency for the CEMs required by Condition No. 5.2.6.

New Permit **Condition No. 5.2.8** requires the parametric monitoring of the lime or sodium bicarbonate feed rate and fuel feed rate to the bubbling fluidized bed boiler of the AFPI.

New **Permit Condition No. 5.2.9** requires daily calibration of the CEMS installed on the AFPI for monitoring emissions of NOx, CO, and SO_2.

New **Permit Condition No. 5.2.10** requires weekly visual inspections of the AFPI baghouse.

New **Permit Condition No. 5.3.4** requires maintenance of records associated with the CEMS for the AFPI needed to demonstrate compliance with the NOx, SO_2, and CO limits to which the AFPI is subject.

Section 6.0: Other Recordkeeping and Reporting Requirements

Permit **Condition No. 6.1.7** is being modified to incorporate new reporting requirements associated with excess emissions, exceedances, and excursions with regards to emission standards and limits contained in the proposed permit amendment.

Permit **Condition No. 6.2.3** is being modified to incorporate the new AFPI into the equation for calculating plant-wide NOx emissions. In addition, the equation is being corrected to account for the daily monitoring of NOx emissions from the natural gas-fired heating units and to make the equation dimensionally correct.

Permit **Condition No. 6.2.4** is being modified to incorporate the new AFPI into the equation for calculating plant-wide CO emissions. In addition, the equation is being corrected to account for the daily monitoring of NOx emissions from the natural gas-fired heating units and to make the equation dimensionally correct.

Permit **Condition No. 6.2.5** is being modified to incorporate the modified NOx and CO emission limits, which now apply to the entire Part 70 site.

Permit **Condition No. 6.2.6** is being deleted; its reporting requirements have been incorporated into other permit conditions.

New Permit **Condition No. 6.2.10** requires monitoring of the use of all HAP-containing materials for compliance with the new site-wide HAP limit of Condition No. 2.1.3.

New Permit **Condition Nos. 6.2.11 and 6.2.12** are being added to incorporate monitoring of plant-wide SO_2 emissions to determine compliance with the new site-wide SO_2 limit contained in Condition No. 2.1.5.

New Permit **Condition No. 6.2.13** requires monitoring of the use of all VOC-containing materials for compliance with the AFPI's VOC limit contained in Condition No. 3.2.4.

New Permit **Condition No. 6.2.14** requires testing of new alternative fuels for the AFPI for sulfur and HAP, including metallic HAP, content.

New Permit **Condition No. 6.2.15** requires monitoring of NOx emissions from the existing Nebraska Boiler on a monthly and rolling 12-month basis in order to ensure compliance with the 4.0 ton per year NOx limit contained in new Permit Condition No. 3.2.6. This monitoring takes effect one year from the date of the initial commencement of operations of the AFPI.

New Permit **Condition No. 6.2.16** requires the reporting of the date on which operation of the AFPI initially commences.

<u>Section 7.0: Other Specific Requirements</u>

No conditions in Section 7.0 are being added, deleted or modified as part of this permit action

APPENDIX A

Draft Revised Title V Operating Permit Amendment
Visy Paper, Inc.
Conyers (Rockdale County), Georgia

APPENDIX B

Pratt Industries (U.S.A.), Inc. NSR Permit Application and Supporting Data

Contents Include:

1. PSD Permit Application Nos. 16655, 16656, and 16657, dated March 15, 2006
2. Additional Information Package Dated May 25, 2006
3. Additional Information Package Dated July 26, 2006
4. Additional Information Package Dated July 27, 2006
5. Additional Information Package Dated September 26, 2006

APPENDIX C

Environmental Justice Maps Provided By U.S. EPA, Region IV