BEST AVAILABLE RETROFIT TECHNOLOGY DETERMINATION
INDIAN RIVER GENERATING STATION UNIT 3
MILLSBORO, DELAWARE

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List of Acronyms and Abbreviations

AIRS	Aerometric Information Retrieval System
BART	Best Available Retrofit Technology
CAIR	Clean Air Implementation Rule
CALPUFF	California Puff Model
CENRAP	Central Regional Air Partnership
dv	deciview
DNREC	Delaware Natural Resources & Environmental Control
EC	elemental carbon
EGU	electric generating unit
ESP	electrostatic precipitator
F	Fahrenheit
FWS	Fish and Wildlife Service
Fps	feet per second
Indian River	Indian River Operations, LLC
IWAQM	Interagency Workgroup on Air Quality Models
km	kilometers
lb/MMBtu	pound per million British thermal units
lbs/hr	pounds per hour
LCC	Lambert Conformal Conic
MPR	Multi-Pollutant Regulation
MANE-VU	Mid-Atlantic Northeast Visibility Union
NAAQS	National Ambient Air Quality Standards
NESCAUM	Northeast States for Coordinated Air Use Management
NOx	nitrogen oxide
NPS	National Park Service
NP	National Park
NWA	National Wilderness Area
PJFF	Pulse jet fabric filter
PM	particulate matter
PM10	particulate matter with aerodynamic size of 10 micron or lower
PMF	fine particulate matter
PMC	coarse particulate matter
RPO	Regional Planning Organization
SCR	Selective Catalytic Reduction
SNCR	Selective non-catalytic reduction
SO_2	sulfur dioxide
tpy	tons per year
USEPA	U.S. Environmental Protection Agency

1.0 Introduction

On January 1, 2007, the Delaware Natural Resources & Environmental Control (DNREC) sent a letter to Indian River Operations, LLC (Indian River) regarding the applicability of the Regional Haze Guidelines for Unit 3 at the Indian River Generating Station in Millsboro, Delaware (Facility). This unit was considered by DNREC as "BART-Eligible" and was required to perform analysis for Best Available Retrofit Technology (BART) Determinations (70 FR 39104). In that letter, DNREC listed two options for complying with the BART:

(i) Consider a permitted emission cap limiting the combined emission from the "BART-Eligible" unit to less than 250 tons per year (tpy) of each visibility impairing pollutant; or

(ii) Perform a BART Determination for the visibility impairing pollutants.

The Facility chose not to consider a permitted emission cap and therefore performed the BART determination.

Because the Unit 3 is an electric generating unit (EGU), participating in DNREC's Multi-Pollutant Regulation (MPR), BART requirements for sulfur dioxide (SO_2) and nitrogen oxides (NOx) will be met through this cap and trade program. In Delaware, MPR integrates the emission limitations of the federal Clean Air Implementation Rule (CAIR). The BART determination is therefore required only for particulate matter with aerodynamic size of 10 micron or less (PM10).

This report provides the BART determination for Unit 3 for PM10.

2.0 Background Information

2.1 Description of Site

The Indian River facility is located on Power Plant Road, in Millsboro, Delaware on the Indian River Bay. Figure 2-1 shows the site within the state of Delaware and nearby natural features. The site contains four coal-fired boilers, one combustion turbine, one oil fired heater, material and ash handling operations, fuel oil tanks, and other miscellaneous emission sources. Initial start up of the facility was in 1957 with Unit 1. Total estimated output from the facility is approximately 767 MW. Figure 2-2 is a site plan showing all four units including Unit 3.

The terrain surrounding the facility is mostly flat with terrain heights reaching 20 feet within 5 kilometers (km) from the property boundary line. The vegetation is mostly grassland. Land use in the surrounding area is mostly rural and coastal. The Indian River Bay draining to the Atlantic Ocean is located due east of the facility. Sussex County is in attainment with the National Ambient Air Quality Standards (NAAQS) for all BART regulated pollutants. The nearest Class I area is the Brigantine National Wilderness Area (Brigantine NWA) under the Fish and Wildlife Service (FWS) and is approximately 127 kilometers (km) northeast of the facility. Also, the Shenandoah National Park (Shenandoah NP) under the National Park Service (NPS) is within 300 km due southeast of the facility.

Unit 3 was determined by DNREC to be "BART-Eligible". The other three units at this facility are not covered by BART program.

2.2 Existing Controls

The existing Unit 3 currently has several elements in place to control emissions. For NOx controls, the Unit 3 boiler is equipped with low-NO_X burners, over fire air, and selective non-catalytic reduction (SNCR) operating during ozone season only. For control of PM/PM_{10} emissions, cold side electrostatic precipitators (ESP) are installed on the backend of the unit.

2.3 Compliance with CAIR/MPR

DNREC agrees to EPA's position that for EGUs covered under CAIR program, compliance with CAIR will constitute compliance with BART for SO_2 and NOx. In Delaware, CAIR program is integrated with the MPR. In addition to the requirements set forth by EPA's federal CAIR program, Delaware has promulgated Regulation 1146 for the control of SO_2 and NOx. The facilities compliance with the MPR is as follows.

For CAIR, the facility will minimize SO_2 and NOx emissions, and for any emissions beyond its CAIR allocation, the facility will surrender allowances as required by the rule. Within the MPR, Delaware has established annual emissions caps for SO_2 and NOx and the facility will operate within the requirements of the rule or any amendments or orders provided by DNREC. For Unit 3, the facility has installed SNCR technology, low NOx burner Technology, and over fire air to reduce NOx emissions. To achieve the limits provided in the regulation, the facility plans to operate the SNCR system on an annual basis beginning in 2008 until Selective Catalytic Reduction (SCR) Technology (or other technologies as feasible) can be installed, anticipated to be available by January 1, 2012. For SO_2, the facility will continue to utilize low sulfur content coal in the range of 0.8% to 1.6% sulfur content until Flue Gas Desulfurization (FGD) Technology (or other technologies as feasible) can be installed, anticipated to be available by January 1, 2012. After the installation of these technologies, the unit will achieve emission rates equal to or less than 0.125 lbs/MMBtu for NOx and 0.26 lbs/MMBtu for SO_2, as required under MPR.

2.4 Elements of BART Analysis

On July 6, 2005, the U.S. Environmental Protection Agency (USEPA) published final amendments to its 1999 Regional Haze Rule in the Federal Register, including Appendix Y, the final guidance for Best Available Retrofit Technology determinations (70 FR 39104-39172). The BART program applies to facilities in one of the 26 source categories that have units installed between August 7, 1962 and August 7, 1977, with the potential to emit more than 250 tpy of a visibility impairing pollutants (SO_2, NOx and PM10). The units meeting these criteria are ”BART-Eligible” units.

The next step is to determine whether these “BART-Eligible” units either “cause” or “contribute” to visibility impairment to Class I area within 300 km. USEPA defined “cause” as an impact of 1.0 deciview (dv) and ‘contribute” as an impact of 0.5 dv or more, compared to natural background.

If the units are determined to either “cause” or “contribute” to visibility impairment in a Class I area, an engineering review is required to determine if installation of new control requirements is appropriate. This engineering review takes into consideration five factors such as: i) cost; ii) energy and non-environmental impacts; iii) existing controls at the units; iv) remaining useful life of the units; and v) visibility improvement reasonably expected from the control technology.

Delaware is part of the Mid-Atlantic/Northeast Visibility Union (MANE-VU) regional Planning organization. In a recent teleconference (July 30, 2007), DENREC informed NRG that it supported MANE-VU’s recommendation that “BART-eligible” units would not be exempted from BART determination based on results of visibility analysis. Though it does not necessarily mean that controls will be required, the BART-eligible units have to complete the “Five Factor” BART analysis mentioned above.

2.5 Class I Areas Considered

As shown in Figure 2-3, there are two Class I areas within a 300 km radius from the Indian River facility. They are: i) Brigantine NWA under the FWS (Brigantine NWA); and the Shenandoah National Park (Shenandoah NP) under the National Park Service (NPS). The Brigantine NWA is approximately127 km due northeast and the Shenandoah NP is approximately 258 km due southeast of the facility.

3.0 Technical Approach and Methodology

DNREC has determined that Unit 3 is a "BART-Eligible" source. The next step is to determine whether the Unit 3 emissions either "caused" or "contributed" visibility impairment in the two Class I areas identified in Section 2.5.

Air dispersion modeling using USEPA approved procedure was performed to determine the visibility impact of the Unit 3 emissions. The air modeling was performed generally in conformance with the following guideline documents:

- Interagency Workgroup on Air Quality Models (IWAQM) Phase 2 Summary report in Modeling Long Range Transport Impacts (USEPA, 1998), commonly referred to as IWAQM Phase 2 Report.
- Federal Land Manager's Air Quality Related Values Workgroup, Phase I Report (12/00), commonly referred to as the FLAG Document.
- BART Resource Guide Prepared by Northeast States for Coordinated Air Use Management (NESCAUM) for the Mid-Atlantic Northeast Visibility Union (MANE-VU) Regional Planning Organization (RPO), dated August 23, 2006.
- CALPUFF User's Guide January 2000.

The rest of this section describes the methodology of the modeling and input data for the model.

3.1 Long Range Transport Model

The California Puff Model (CALPUFF) was promulgated by the USEPA on April 15, 2003 as a preferred dispersion model to assess long-range transport applications (i.e. transport distances exceeding 50 km to approximately 300 km). Up to this distance, a non-steady-state modeling approach which considers spatial and time variations in meteorological conditions, such as CALPUFF, is appropriate. For this modeling demonstration, CALPUFF Version 5.711a was used, consistent with the approved BART version.

In July 2007, USEPA released version 5.8 of the CALPUFF model and also updated the CALMET and CALPOST programs. In the July 30, 2007 teleconference, DENREC confirmed that CALPUFF version 5.711a still could be used for this analysis since revised meteorological data set for the new version of the CALPUFF model has not be developed yet by NESCAUM.

CALPUFF is a multi-layer, multi-species, non-steady state puff dispersion model which can simulate the time and space varying meteorological conditions on pollutant transport, transformation, and removal. CALPUFF uses three dimensional meteorological fields developed by the meteorological processing program CALMET.

CALPUFF contain algorithms for near source effects such as building downwash, traditional plume rise, partial plume penetration, sub-grid scale terrain interactions, as well as long range effects such as pollutant removal (dry and wet deposition), chemical transformation, vertical wind shear, over-water transport, and coastal interaction effects.

The post processor CALPOST version 5.51 was used in this analysis to process the CALPUFF data and derive the maximum incremental visibility impact due to Unit 3 operations as a change in deciviews (dv) at the Class I areas.

3.2 Computational Grid

The CALMET data was received from NESCAUM for use in this analysis. The CALMET field that was generated NESCAUM covers multiple states in the Mid-Atlantic and northeast United States. The computational grid is generally a subset of the meteorological grid, and the CALPUFF computational grid system utilized for this modeling demonstration extended at least 50 kilometers in all directions beyond the Indian River Generating Station along with any portions of the two Class I areas. The additional buffer distance of at least 50 km is allowed for the consideration of puff trajectory recirculation. Figure 3-1 shows the meteorological and modeling domains. Due to the size of the modeling domain used for this analysis, a Lambert Conformal Conic (LCC) coordinate system was used. The LCC projection was used because it accounted for the curvature of the Earth's surface.

3.3 Source Parameters

The source parameters include stack parameters and emission rates. The BART determination was limited to Unit 3 and the stack parameters are shown in Table 3-1.

Table 3-1
Stack Parameters for Unit 3

UTM Northing (km)	Base Elev ation (ft)	Stack Heig ht (ft)	Stack Temp eratu re (°F)
4336.8312	3.31	385	300

The BART determination was limited to PM10 only per DNREC. However, SO_2 and NOx are known to be precursors of secondary particulates (e.g. sulfates and nitrates) formed in the atmosphere during long-range transport and therefore were included in the modeling.

As mentioned in Section 2.3, the Unit 3 will be complying with DNREC's MPR by January 1, 2012. The permitted emission limits for SO_2 and NOx at this time (Phase II of MPR) will be 0.26 lb/MMBtu and 0.125 lb/MMBtu, respectively. These emission limits were used to estimate the maximum hourly emission rates as shown in Table 3-2.

Currently, Unit 3 is equipped with cold-side ESP, which is state of the art control technology for these types of boilers. The permitted limit for PM for Unit 3 as per the existing Title V operating permit is 0.3 lb/MMBtu (2-hour average). This emission limit was used for estimating maximum hourly PM10 emission rate as shown in Table 3-2.

Typically, the 24-hour averaged emission rates are lower than maximum hourly emission rates. However, to be conservative, the maximum hourly emission rates were considered to be same as maximum 24 hour emission rates and were used in the modeling.

Table 3-2
Maximum 24-hour Average Emission Rates for the Unit 3

Pollutant	Emission Limit (Lbs/MMBtu)	Unit 3 Nominal Heat Input Rate (MMBtu/hr)	Maximum Hourly Emission Rate (Lbs/hr)/(Grams/Sec)	Maximum 24-Hour Average Emission Rate (Lbs/hr)/Grams/Sec)
SO2	0.26	1,904	495/62.37	495/62.37
NOx	0.125	1,904	238/29.99	238/29.99
PM10	0.30	1,904	571/71.94	571/71.94

The particulate matter is required to be segregated into coarse and fine particulate as well as elemental carbon, since each of these have different light extinction coefficients. Fine particulates are of aerodynamic size 2.5 micron or lower and coarse particulate are of aerodynamic size greater than 2.5 microns. The fine and coarse particulate matter are further segregated to condensable (both organic and inorganic). The exit temperature of gases from Unit 3 stack is approximately 300 Fahrenheit (F). Also, there are no selective catalytic reduction (SCR) or FGDs in place. Thus, very little if any of the emissions are expected to be condensable, either organic or inorganic. All particulate matter was therefore considered as filterable. The PM was segregated to PM fines (PMF in CALPUFF) and PM coarse (PMC in CALPUFF) using AP-42 speciation for dry bottom pulverized coal boilers using bituminous coal and ESP controls. Elemental carbon (EC in CALPUFF) was considered as 1% of total PM as per USEPA guidelines.

3.4 Building Downwash Analysis

Both Class I areas were greater than 50 km from the Unit 3 stack. At this distance, the effect of building downwash is negligible. Therefore, building downwash analysis was not performed.

3.5 Meteorological Data

The meteorological data utilized in this analysis was the 2002 MANE-VU-developed CALMET dataset obtained from the Northeast States for Coordinated Air Use Management (NESCAUM). This data was provided on an external hard drive, and was utilized in this source-specific BART analysis. The dataset includes surface level observation from meteorological stations.

3.6 Receptor Layout

The NPS has predetermined locations of receptors in each Class I Area. These were used for the modeling. The receptor layout for the Brigantine NWA and the Shenandoah NP are shown in Figures 3-2 and 3-3, respectively.

3.7 Background Concentrations of Ammonia and Ozone

CALPUFF/CALPOST requires background concentration for ammonia and ozone to use the chemical transformation algorithms. Annual average ozone concentration was obtained from EPA's CAST-Net site for Shenandoah NPS for 2002. Attachment 1 shows a copy of the report obtained from the site. For Brigantine NWA, the annual average ozone concentration was obtained from EPA's Aerometric Information Retrieval System (AIRS) database for 2002. Attachment 1 shows a copy of the report obtained from this database. Since there was multiple ozone monitoring stations in Brigantine NWA, the highest ozone concentration was selected.

There were no known sites for ammonia background concentrations at these two Class I areas. Therefore, a default value of 0.5 ppb was selected. The background concentrations used in the modeling are shown in Table 3-3.

Table 3-3
Background Concentrations of Ozone and Ammonia used in Visibility Impact Modeling

Pollutant	Brigantine NWA	Shenandoah NPS
Ozone	57.5 ppb	50 ppb
Ammonia	0.5 ppb	0.5 ppb

The ammonia limiting method was not used as per NESCAUM BART Resource Guide.

3.8 Background Light Extinction Coefficient

For visibility impact analysis, the natural background concentration for several species is required. This includes ammonium sulfate, ammonium nitrate, organic carbon, elemental carbon, soil and coarse particulate. The monthly natural background concentration coefficients were taken from Table 6-3 of the Central Regional Air Partnership (CENRAP) protocol and were based on the average natural concentration for the eastern United States. These are shown in Table 3-4.

Table 3-4
Background Concentration of Species in Eastern United States for Visibility Impact Modeling

Parameter	BKSO4	BKNO3	BKPMC	BKSOC	BKSSOIL	BKSEC
Concentration (μg/m³)	0.23	0.10	3.00	1.40	0.50	0.02

3.9 Relative Humidity Method

Relative humidity is required at the Class I area to estimate the visibility impacts. Two methods are currently used in CALPUFF for incorporating relative humidity:

- Method 2, which requires hourly relative humidity data to be used in CALMET.
- Method 6, which requires monthly averaged relative humidity data.

Per the NESCAUM BART Resource Guide, Method 6 was used in the analysis with the monthly average humidity based on the centroid of the area. The relative humidity was capped at 98% for generating the factors used for particle growth in CALPUFF. These factors are listed in Table 3-5 for reference.

Table 3-5
Monthly Relative Humidity Factors Use in Visibility Impact Modeling

Class I Area	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sept	Oct	Nov	Dec
Brigantine	2.9	2.6	2.7	2.6	2.9	3.0	3.2	3.4	3.4	3.2	2.8	2.9
Shenandoah	2.9	2.6	2.7	2.4	2.9	3.1	3.2	3.5	3.5	3.0	2.7	2.9

3.10 Rayleigh Scattering Coefficient

CALPOST uses a default Rayleigh scattering coefficient of 10 Mm^{-1}. This default value was used in this analysis.

3.11 CALPUFF Model Settings

All USEPA default settings were used in the CALPUFF model and the CALPOST post processor.

4.0 Results of Analysis

This section contains the results of the BART regional haze analysis. All modeling input and output files are included in electronic form on CD-ROM in Attachment 2 of this report.

4.1 Visibility Impact Analysis for Baseline Condition

Perceived visibility in deciview is derived from the light extinction coefficient. The visibility change related to background is calculated using the modeled and established natural visibility conditions. For the BART screening analysis, daily visibility is expressed as a change in deciview compared to natural visibility conditions.

Sources with modeled 98th percentile (8th highest in one year) impacts below the 0.5 dv threshold are considered not to "cause' or "contribute" to visibility impairment and no further controls are necessary. Sources with impacts at, or above, 0.5 dv can either perform refined CALPUFF modeling to show their visibility impact is in fact below the 0.5 dv threshold or continue with the BART process and perform a five factor BART analysis.

As mentioned earlier, the facility will comply with the BART controls for SO2 and NOx by complying with the MPR. This BART analysis is therefore for PM10 only. However, since SO2 and NOx also would contribute to visibility degradation, the analysis was performed for two emission scenarios:

- Emission Scenario 1: Visibility impact was determined considering PM10 emissions only; and
- Emission Scenario 2: Visibility impact was determined considering SO2, NOx, and PM10 emissions.

For both emission scenarios, a baseline impact was determined considering the current PM10 control device (i.e. cold side ESP) and MPR assigned emission rates for SO2 and NOx. The results of the analysis are presented in Tables 4-1a and 4.1b. For Scenario 1, the 8th highest 24-hour impact at Brigantine NWA and Shenandoah NP were 0.098 delta deciview and 0.007 delta deciview, respectively. For emission scenario 2, the 8th highest 24-hour impact at Brigantine NWA and Shenandoah NP were 0.098 delta deciview and 0.007 delta deciview, respectively. In both emission scenarios and for both Class I areas, the maximum impacts were well below the 0.5 delta deciview threshold for contributing to the visibility impairment.

Therefore, Unit 3 emissions neither "cause" nor "contribute" to a perceptible regional haze impact at the two Class I areas considered in the analysis.

Table 4-1a: Baseline Visibility Impact Analysis Results at the Class I Areas: Method 6 Annual Average Conditions as Background
Emission Scenario 1: PM10 Emissions Only

Class I Area	Rank (highest to lowest)	Julian Day	Receptor Location		Delta Deciview
			x	y	
Brigantine NWA	1	257	1916.898	185.879	0.173
	2	147	1906.799	185.211	0.16
	3	6	1918.281	189.085	0.128
	4	51	1904.279	186.473	0.118
	5	23	1906.799	185.211	0.117
	6	313	1904.506	185.58	0.113
	7	223	1904.506	185.58	0.103
	8	**38**	**1916.898**	**185.879**	**0.098**
Shenandoah NP	1	85	1602.75	-6.918	0.04
	2	84	1608.439	43.221	0.021
	3	233	1592.264	-20.383	0.017
	4	239	1574.426	-56.014	0.016
	5	282	1611.47	28.794	0.011
	6	283	1611.739	34.5	0.01
	7	172	1606.656	44.73	0.008
	8	**240**	**1607.078**	**14.693**	**0.007**

Table 4-1b: Baseline Visibility Impact Analysis Results at the Class I Areas: Method 6 Annual Average Conditions as Background Emission Scenario 2: SO2/NOx/PM10 Emissions

Class I Area	Rank (highest to lowest)	Julian Day	Receptor Location		Delta Deciview
			x	y	
Brigantine NWA	1	344	1906.799	185.211	0.466
	2	215	1916.209	185.704	0.401
	3	174	1916.898	185.879	0.388
	4	71	1918.281	189.085	0.382
	5	173	1918.281	189.085	0.358
	6	223	1904.506	185.58	0.33
	7	126	1916.898	185.879	0.322
	8	**6**	**1918.281**	**189.085**	**0.316**
Shenandoah NP	1	85	1602.75	-6.918	0.273
	2	239	1574.426	-56.014	0.17
	3	84	1606.422	10.79	0.153
	4	233	1574.426	-56.014	0.135
	5	283	1610.98	38.106	0.094
	6	282	1611.47	28.794	0.059
	7	206	1574.426	-56.014	0.056
	8	**285**	**1606.142**	**5.084**	**0.055**

5.0 BART Analysis and Determination

DENREC requires a five factor analysis for BART determination for all "BART Eligible" sources irrespective of the results of the visibility analysis as per recommendations of MANE-VU. The procedure is described in 40 CFR Part 51 regional Haze regulations and Guidelines for Best Available Retrofit Technology (BART) Determinations: Final Rule (USEPA). The Rule identification of the BART considering following five statutory factors:

- Cost;
- Energy and non-environmental impacts;
- Existing controls in place;
- Remaining useful life of source; and
- Visibility improvement reasonably expected from the technology

The analysis for Unit 3 PM control is described in following sections.

5.1 Identifying Alternative Control Technologies

As mentioned earlier, SO2 and NOx controls will be in place for Unit 3 in compliance with the MPR, which qualifies as compliance with BART. The alternative control technology assessment was therefore limited to particulates.

The Unit 3 is equipped with cold-side ESP, which is the state of art control technology for particulate matter control for this type of boilers. The ESP is maintained as required by the manufacturer and is operating effectively. The performance of ESP depends on many operating variables including coal type. At this time, the ESP is considered to be operating effectively and therefore any further modification to the ESP is not expected to result in significant improvement in particulate control. Thus, alternative technologies were assessed based on either a stand alone (i.e. replacement of the ESP) or adding a secondary particulate control after the existing ESP.

Potentially stand alone applicable particulate control technologies for coal fired boilers in lieu of cold side ESP are:

- Multiclones; and
- Fabric filters;

Multiclones:

Multiple-cyclone separators, also known as multiclones, consist of a number of small diameter cyclones, operating in parallel and having a common gas inlet and outlet. Multiclones operate on the same principle as cyclones, creating a main downward vortex and an ascending inner vortex. The centrifugal force of the vortex generated in individual cyclones result in separation of the particulates from the flue gas which then fall down to a centralized hopper. The cleaner gas passes through an outlet common plenum to the outlet duct.

Multiclones are more efficient that single cyclones because they are longer and smaller in diameter. The longer length provides longer residence time while the smaller diameter creates greater centrifugal force. These two factors result in better separation of dust particulates. The pressure drop of multiclone collectors is higher than that of single-cyclone separators. At pressures near one atmosphere and 2 to 5 in. water gauge pressure differential, this technology can effectively remove particles larger than 20 microns in size; particles less than 10 microns are usually unaffected and not removed.

Multiclones were the first type of particulate control used for coal fired boilers. However, the overall particulate collection efficiency is less than what is required to meet current emission standards. These are sometimes used now as primary collector upstream of a final collector such as an ESP or a fabric filter.

Multiclone as a stand alone particulate control is considered to be infeasible in maintaining the desired emission standards for Unit 3 and therefore not considered further in the analysis.

Pulse jet fabric filter baghouse:

Pulse jet fabric filter (PJFF) baghouses have been used for collection of particulate from coal fired boilers. Fabric filters are media filters that the flue gas passes through to remove the particulate. Cloth filter media is typically sewn into cylindrical tubes called bags. Each fabric filter may have thousands of these filter bags. The filter unit is typically divided into compartments, which allows online maintenance or bag replacement. The quantity of compartments is determined by maximum economic compartment size, total gas volume rate, air-to-cloth (A/C) ratio, and cleaning system design. Extra compartments for maintenance or off-line cleaning increase the reliability at the expense of capital cost and real estate utilization. Each compartment includes at least one hopper for temporary storage of the collected fly ash.

Fabric bags vary in composition, length, and cross-section (diameter or shape). Bag selection characteristics vary with cleaning technology, emissions limits, flue gas and ash characteristics, desired bag life, capital cost, A/C ratio, and pressure differential. Fabric bags are typically guaranteed for 3 years but frequently last 5 years or more.

In pulse jet fabric filters, the flue gas typically enters the compartment hopper and passes from the outside of the bag to the inside, depositing particulate on the outside of the bag. To prevent the collapse of the bag, a metal cage is installed on the inside of the bag. The flue gas passes up through the center of the bag into the outlet plenum. The bags and cages are suspended from a tube sheet.

Cleaning is performed by initiating a downward pulse of air into the top of the bag. The pulse causes a ripple effect along the length of the bag. This releases the dust cake from the bag surface. The dust then falls into the hopper. This cleaning may occur with the compartment online or off line. Care must be taken during design to ensure that the upward velocity between the bags is minimized so that particulate is not re-entrained during the cleaning process. The PJFF cleans bags in sequential, usually staggered, rows. During online cleaning, part of the dust cake from the row being cleaned may be captured by the adjacent rows. Despite this apparent shortcoming, PJFF have successfully implemented online cleaning on many large units.

The PJFF bags are typically made of felted materials that do not rely as heavily on the dust cakes filtering capability as woven fiberglass bags. This allows the PJFF bags to be cleaned more vigorously. The felted materials also allow the PJFF to operate at a much higher cloth velocity, which significantly reduces the size of the unit and the space required for installation.

PJFF is considered technically feasible technology for Unit 3 particulate control and therefore considered in the analysis. A review of USEPA's RACT/BACT/LAER Control (RBLC) clearinghouse showed that fabric filters have been used for coal fired boilers with outlet emission of as low as 0.015 lbs/MMBtu. The emission rate was confirmed by several vendors contacted for this application. Therefore, outlet emission of 0.015 lbs/MMBtu (filterable) was considered for the visibility impact analysis for the control technology. This emission limit is lower than the presumptive PM10 emission limits considered by MANE-VU for CAIR EGUs, which is 0.02-0.04 lbs/MMBtu.

Wet ESP:

Wet ESPs are commonly used for acid and organic mist collection. Although there are few applications in the utility industry, there are hundreds of industrial applications. Wet ESP as a stand alone particulate control (such as replacement of existing dry ESP) has not been considered for utility industry because: i) there is no inherent advantage of wet ESP over dry ESP if acid mists are not present; and ii) wet ESPs operate at far lower temperature range than dry ESP and therefore the flue gas has to be cooled down to 120-150 F range for its use, which makes it uneconomical compared to a dry ESP.

However, wet ESPs have been proposed and used downstream of wet flue gas desulfurization (FGD) systems. Wet FGDs scrub SO2 but also generate some particulate in the form of acid mists due to near dew point temperatures at the scrubber outlet. The wet ESP is used to remove the additional acid mists from the gas stream.

Wet ESPs have been also used as an integral part of multi-pollutant control systems. One such system is the Electro-Catalytic oxidation (ECO) developed by Powerspan Inc. The ECO system is an integrated air pollution control technology that achieves major reductions in the primary air pollutants of concern from coal-fired power plants, specifically 99% reduction of sulfur dioxide (SO2) emissions, 90% of nitrogen oxide (NOx) emissions, 80-90% of mercury (Hg) emissions, and 95% of fine particulate matter (PM2.5) emissions. The system also provides high removal of other metals and acid gases such as sulfuric acid (SO3/H2SO4), hydrochloric acid (HCl), and hydrofluoric acid (HF). The ECO system produces a valuable, ammonium sulfate fertilizer co-product, reducing operating costs and minimizing landfill disposal of waste.

The ECO process treats power plant flue gas in three steps to achieve multi-pollutant removal:

1. ECO Reactor: oxidizes pollutants;
2. Absorber Vessel: removes SO2, NO2, and oxidized mercury; and
3. Wet Electrostatic Precipitator (ESP): removes acid aerosols, air toxics, and fine particulates

After exiting the absorber vessel, the flue gas enters a wet ESP. Aerosols generated in the ECO reactor and ammonia scrubbing process steps, along with air toxics and fine particulate matter, are captured in the wet ESP and returned to the lower loop of the scrubber. In commercial operation the ECO system is installed downstream of a power plant's existing electrostatic precipitator or fabric filter.

Wet ESPs differ from dry ESPs in that liquid flows down the collecting plate, removing collected material from its surface as opposed to mechanically rapping or employing sonic horns to remove the material from the plate as is done in dry ESPs. The liquid layer created on the collection plate of wet ESPs prevents particle re-entrainment, improving its collection characteristics over dry ESPs. The improved collection permits higher gas velocities, limiting the equipment size required.

Wet ESPs have been used successfully in industrial applications to collect acid aerosols for over 50 years, particularly in metallurgical plants and in sulfuric acid manufacturing. Wet ESPs have shown to be efficient collectors of PM2.5 and hazardous air pollutants such as mercury.

NRG is committed to multi-pollutant control to meet the requirements of MPR. Though the exact technology for multi-pollutant control has not been selected at this time, there is strong possibility of using a wet scrubbing process for reducing SO2 emissions. In that case, use of wet ESP as the final air pollution control device is feasible on Unit 3. A wet ESP is therefore considered in this analysis.

Discussion with vendors (Powerspan) indicated that particulate emission level of 0.01 lbs/MMBtu can be achieved for IR Unit 3 and therefore this was considered as the basis for BART analysis. This emission limit is lower than the presumptive PM emission limits considered by MANE-VU for CAIR EGUs, which is 0.02-0.04 lbs/MMBtu.

Thus, the two control technologies selected for BART analysis are:

- A Pulse Jet Fabric Filter baghouse with outlet PM emission of 0.015 lbs/MMBtu; and
- A wet ESP as part of multi-pollutant control with outlet PM emission of 0.010 lbs/MMBtu

5.2 Estimating Cost of Compliance and Cost Effectiveness

The next step in the BART analysis is to estimate the cost of compliance for the technically feasible technologies. Both capital and annual operating costs were estimated based on discussion with vendors and available published data. Brief description of the methodology is as follows and the cost determination can be found in Attachment 3.

The total installed capital cost includes direct costs and indirect costs. Direct costs are from purchased equipment cost and equipment construction cost at site. For the PJFF option, site construction costs also include demolition of the existing ESP and rerouting of ducting to the proposed PJFF. Though demolition of existing ESP is not needed for the Wet ESP option, significant rerouting of ducting is required to make available the necessary equipment footprint. Indirect costs include engineering/supervision fees, general construction and field expenses, construction fee, start-up costs, performance test costs, and contingencies. The estimate for indirect costs was obtained from USEPA OAQPS Control Cost Manual.

Annual operational costs were estimated for both options. The direct costs for operation included: i) maintenance costs; general facility operation costs, contingencies, engineering costs, environmental compliance costs, and cost of utility. For estimation of utility cost, a pressure drop of 6 inch water gage (wg) for the PJFF and 1 inch wg for wet ESP were considered. Indirect operating costs were overhead, property taxes, G&A, and insurance charges.

The estimated cost for the two alternative technology options and cost effectiveness are shown in Table 5-1.

Table 5-1
Cost Effectiveness for Alternative Control Technologies

Control Technology	Emission Rate (lb/ MMBtu)	Emissions (ton/yr)	Expected Emissions reductions (tons/year)	Capital Cost $	Direct Cost $	Indirect Cost $	Total Annualized Cost $	Average Cost Effectiveness ($ per ton of pollutant removed)	Incremental Cost Effectiveness ($ per ton of pollutant removed)
Baseline (existing Cold side ESP)	0.3	2501.86	-	-	-	-	-	-	-
Pulse Jet Fabric Filter	0.015	125.09	2376.76	$43,419,200	$20,330,504	$15,621,995	$35,952,499	$15,127	-
Wet ESP after FGD	0.01	83.40	2418.46	$88,270,292	$39,882,776	$31,759,177	$71,641,952	$29,623	$855,911

5.3 Determining Energy and Non-environmental Impacts

There is no significant energy or non-environmental impacts for either the PJFF or the wet ESP. The higher pressure drop in the PJFF will result in some increase in power requirement. The PJFF will generate dry ash in the hopper which will be transported to the landfill on the site as is currently done with the ash from existing ESP.

The Wet ESP consumes electric power similar to dry ESP and thus there will be no significant change in power demand. The additional condensable acid mist generated by wet FGD up stream is effectively captured in the Wet ESP. The small quantity of wastewater stream from the wet ESP would be connected to the plant's existing discharge system and thus will have no significant water quality impact.

5.4 Existing Controls

As mentioned earlier, the existing control at Unit 3 for particulate matter is a cold side ESP, which is state of art for coal fired boiler of the type in Unit 3.

5.5 Remaining Useful Life of the Unit

Since the remaining useful life for Unit 3 is expected to be greater than the life of the control options, no further consideration of this parameter is needed in the analysis.

5.6 Visibility Improvement Reasonably Expected

Results (Section 4) showed that the impact of Unit 3 emissions after implementation of MPR does not "cause" or "contribute" to any perceived visibility impairment in the two Class I areas within 300 km from the facility. Similar modeling was performed for the two alternative control technology options. This section presents the results of the visibility impact modeling for the two control technology options.

Both emission scenarios 1 and 2 were modeled. For reference, the two emission scenarios were:

- Emission Scenario 1: Visibility impact was determined considering PM10 emissions only; and
- Emission Scenario 2: Visibility impact was determined considering SO2, NOx, and PM10 emissions.

Table 5-2 shows the source parameters used in the modeling. The fabric filter was considered to operate in the same temperature range as the cold side ESP. Since a wet FGD system is considered upstream of the wet ESP, the temperature of flue gas was considered to be 134 F (329 K) as per discussion with a vendor. The source parameters from the existing ESP (baseline) are also shown in Table 5-2 for reference. The source parameters were same for the baseline and fabric filter emission scenarios.

Table 5-2
Source Parameters for Alternative Control Technologies

Alternative Control Technology	PM 10 Emission Rate	Stack Height	Base Elevation	Stack Diameter	Exit Velocity	Exit Temp.
	(lb/MMBtu)	(m)	(m)	(m)	(m/s)	(K)
Baseline (ESP)	0.30	117.348	1.01	4.115	23.5	422.039
Pulse Jet Fabric Filter	0.015	117.348	1.01	4.115	23.5	422.039
Wet ESP after FGD	0.01	117.348	1.01	4.115	19.8	329.817

Table 5-3a, 5-3b, 5-3c, and 5-3d show the results of CALPUFF modeling at the Brigantine NWA and the Shenandoah NP for emission scenario 1 and 2. The 98th percentile (8th highest) values for both emission scenarios are shown in these tables.

Table 5-3a: Visibility Impact Analysis Results at the Class I Areas: Method 6
Annual Average Conditions as Background
Emission Scenario 1: PM10 Emissions Only

Alternative Technology Option 1: Pulse Jet Fabric Filter

Class I Area	Rank (highest to lowest)	Julian Day	Receptor Location x	Receptor Location y	Delta Deciview
Brigantine NWA	1	257	1916.898	185.879	0.01
	2	147	1906.799	185.211	0.009
	3	6	1918.281	189.085	0.007
	4	23	1906.799	185.211	0.007
	5	51	1904.279	186.473	0.007
	6	313	1905.195	185.755	0.007
	7	38	1916.898	185.879	0.006
	8	**151**	**1916.898**	**185.879**	**0.006**
Shenandoah NP	1	85	1602.75	-6.918	0.003
	2	84	1608.439	43.221	0.002
	3	233	1583.156	-33.544	0.001
	4	239	1574.426	-56.014	0.001
	5	240	1604.636	12.3	0.001
	6	282	1611.47	28.794	0.001
	7	283	1611.739	34.5	0.001
	8	**1**	**1570.525**	**-58.686**	**0.000**

Table 5-3b: Visibility Impact Analysis Results at the Class I Areas: Method 6
Annual Average Conditions as Background
Emission Scenario 1: PM10 Emissions Only

Alternative Technology Option 2: Wet ESP after FGD

Class I Area	Rank (highest to lowest)	Julian Day	Receptor Location		Delta Deciview
			x	y	
Brigantine NWA	1	6	1916.898	185.879	0.007
	2	147	1906.346	186.997	0.006
	3	257	1916.898	185.879	0.006
	4	88	1916.898	185.879	0.005
	5	23	1906.799	185.211	0.004
	6	38	1916.209	185.704	0.004
	7	51	1904.279	186.473	0.004
	8	**313**	**1904.506**	**185.58**	**0.004**
Shenandoah NP	1	84	1610.98	38.106	0.001
	2	85	1602.75	-6.918	0.001
	3	233	1574.426	-56.014	0.001
	4	239	1574.426	-56.014	0.001
	5	1	1570.525	-58.686	0.000
	6	2	1570.525	-58.686	0.000
	7	3	1570.525	-58.686	0.000
	8	**4**	**1570.525**	**-58.686**	**0.000**

**Table 5-3c: Visibility Impact Analysis Results at the Class I Areas: Method 6
Annual Average Conditions as Background
Emission Scenario 1: PM10/SO2/NOx Emissions**

Alternative Technology Option 1: Pulse Jet Fabric Filter

Class I Area	Rank (highest to lowest)	Julian Day	Receptor Location		Delta Deciview
			x	y	
Brigantine NWA	1	344	1906.799	185.211	0.404
	2	71	1918.281	189.085	0.346
	3	174	1916.898	185.879	0.319
	4	215	1916.209	185.704	0.315
	5	173	1918.281	189.085	0.289
	6	126	1916.898	185.879	0.259
	7	216	1918.281	189.085	0.25
	8	**222**	**1904.279**	**186.473**	**0.244**
Shenandoah NP	1	85	1602.75	-6.918	0.237
	2	239	1574.426	-56.014	0.155
	3	84	1606.422	10.79	0.136
	4	233	1574.426	-56.014	0.12
	5	283	1610.98	38.106	0.084
	6	206	1574.426	-56.014	0.053
	7	285	1606.142	5.084	0.051
	8	**252**	**1606.656**	**44.73**	**0.049**

**Table 5-3d: Visibility Impact Analysis Results at the Class I Areas: Method 6
Annual Average Conditions as Background
Emission Scenario 1: PM10/SO2/NOx Emissions**

Alternative Technology Option 2: Wet ESP after FGD

Class I Area	Rank (highest to lowest)	Julian Day	Receptor Location		Delta Deciview
			x	y	
Brigantine NWA	1	71	1917.82	188.017	0.367
	2	215	1904.506	185.58	0.361
	3	173	1918.281	189.085	0.345
	4	6	1918.281	189.085	0.344
	5	174	1916.898	185.879	0.33
	6	214	1918.281	189.085	0.328
	7	126	1916.898	185.879	0.3
	8	**216**	**1918.281**	**189.085**	**0.252**
Shenandoah NP	1	85	1611.47	28.794	0.227
	2	239	1574.426	-56.014	0.149
	3	233	1574.426	-56.014	0.141
	4	84	1606.142	5.084	0.139
	5	283	1611.739	34.5	0.07
	6	206	1574.426	-56.014	0.051
	7	251	1606.656	44.73	0.047
	8	**252**	**1606.656**	**44.73**	**0.046**

5.7 Summary

Tables 5-4a and 5-4b summarize the BART analysis for the Unit 3 for particulates. As shown in these tables, the changes in visibility impact for both alternative control technologies are minimal over the baseline for both emission scenarios. The changes are less than 0.1 dv, which is considered the threshold for a significant impact as per DENREC. On the other hand, as shown in Table 5-1, the cost effectiveness of the two alternative technologies are substantial, in the order of $15,126/ton and $29,622/ton of particulate removed for the PJFF (option 1) and wet ESP (Option 2), respectively. The incremental cost effectiveness of the wet ESP option over the PJFF option is approximately $855,900/ton of particulate removed.

Tables 5-5a and 5-5b show the cost effectiveness of the two alternative control technology options in terms of improvement in visibility over baseline. The cost for even marginal change in visibility of 1 dv is substantial for both options.

Table 5-4a
Change in Delta Deciview from Baseline Scenario (ESP)
Emission Scenario 1: PM10 Emissions Only

Class I Area	Parameter	Baseline	Pulse Jet Fabric Filter	Wet ESP after FGD
Brigantine NWA	**8th Highest Delta Deciview**	0.098	0.006	0.004
	Difference from Baseline	-	**0.092**	**0.094**
Shenandoah NP	**8th Highest Delta Deciview**	0.007	0.000	0.000
	Difference from Baseline	-	**0.007**	**0.007**

Table 5-4b
Change in Delta Deciview from Baseline Scenario (ESP)
Emission Scenario 2: PM10/SO2/NOx Emissions

Class I Area	Parameter	Baseline	Pulse Jet Fabric Filter	Wet ESP after FGD
Brigantine NWA	**8th Highest Delta Deciview**	0.316	0.244	0.252
	Difference from Baseline	-	**0.072**	**0.064**
Shenandoah NP	**8th Highest Delta Deciview**	0.055	0.049	0.046
	Difference from Baseline	-	**0.006**	**0.009**

Table 5-5a
Cost Effectiveness for Visibility Improvement for Alternative Control Technologies
Brigantine NWA

Control Technology	Emission Rate (lb/ MMBtu)	Visibility Impact (dv)	Expected Change in Visibility Impact from Baseline	Capital Cost $	Direct Cost $	Indirect Cost $	Total Annualized Cost $	Average Cost Effectiveness ($ per change in dv)
Baseline (existing Cold side ESP): Emission Scenario 1	0.3	0.098	-	-	-	-	-	-
Pulse Jet Fabric Filter: Emission Scenario 1	0.015	0.006	0.092	$43,419,200	$20,330,504	$15,621,995	$35,952,499	**$390,788,030**
Wet ESP after FGD: Emission Scenario 1	0.01	0.004	0.094	$88,270,292	$39,882,776	$31,759,177	$71,641,952	**$762,148,429**
Baseline (existing Cold side ESP): Emission Scenario 2	0.3	0.316	-	-	-	-	-	-
Pulse Jet Fabric Filter: Emission Scenario 2	0.015	0.244	0.072	$43,419,200	$20,330,504	$15,621,995	$35,952,499	**$499,340,261**
Wet ESP after FGD: Emission Scenario 2	0.01	0.252	0.064	$88,270,292	$39,882,776	$31,759,177	$71,641,952	**$1,119,405,505**

Table 5-5b
Cost Effectiveness for Visibility Improvement for Alternative Control Technologies
Shenandoah NP

Control Technology	Emission Rate (lb/ MMBtu)	Visibility Impact (dv)	Expected Change in Visibility Impact from Baseline	Capital Cost $	Direct Cost $	Indirect Cost $	Total Annualized Cost $	Average Cost Effectiveness ($ per change in dv)
Baseline (existing Cold side ESP): Emission Scenario 1	0.3	0.007	-	-	-	-	-	-
Pulse Jet Fabric Filter: Emission Scenario 1	0.015	0	0.007	$43,419,200	$20,330,504	$15,621,995	$35,952,499	**$5,136,071,253**
Wet ESP after FGD: Emission Scenario 1	0.01	0	0.007	$88,270,292	$39,882,776	$31,759,177	$71,641,952	**$10,234,564,614**
Baseline (existing Cold side ESP): Emission Scenario 2	0.3	0.055	-	-	-	-	-	-
Pulse Jet Fabric Filter: Emission Scenario 2	0.015	0.049	0.006	$43,419,200	$20,330,504	$15,621,995	$35,952,499	**$5,992,083,128**
Wet ESP after FGD: Emission Scenario 2	0.01	0.046	0.009	$88,270,292	$39,882,776	$31,759,177	$71,641,952	**$7,960,216,922**

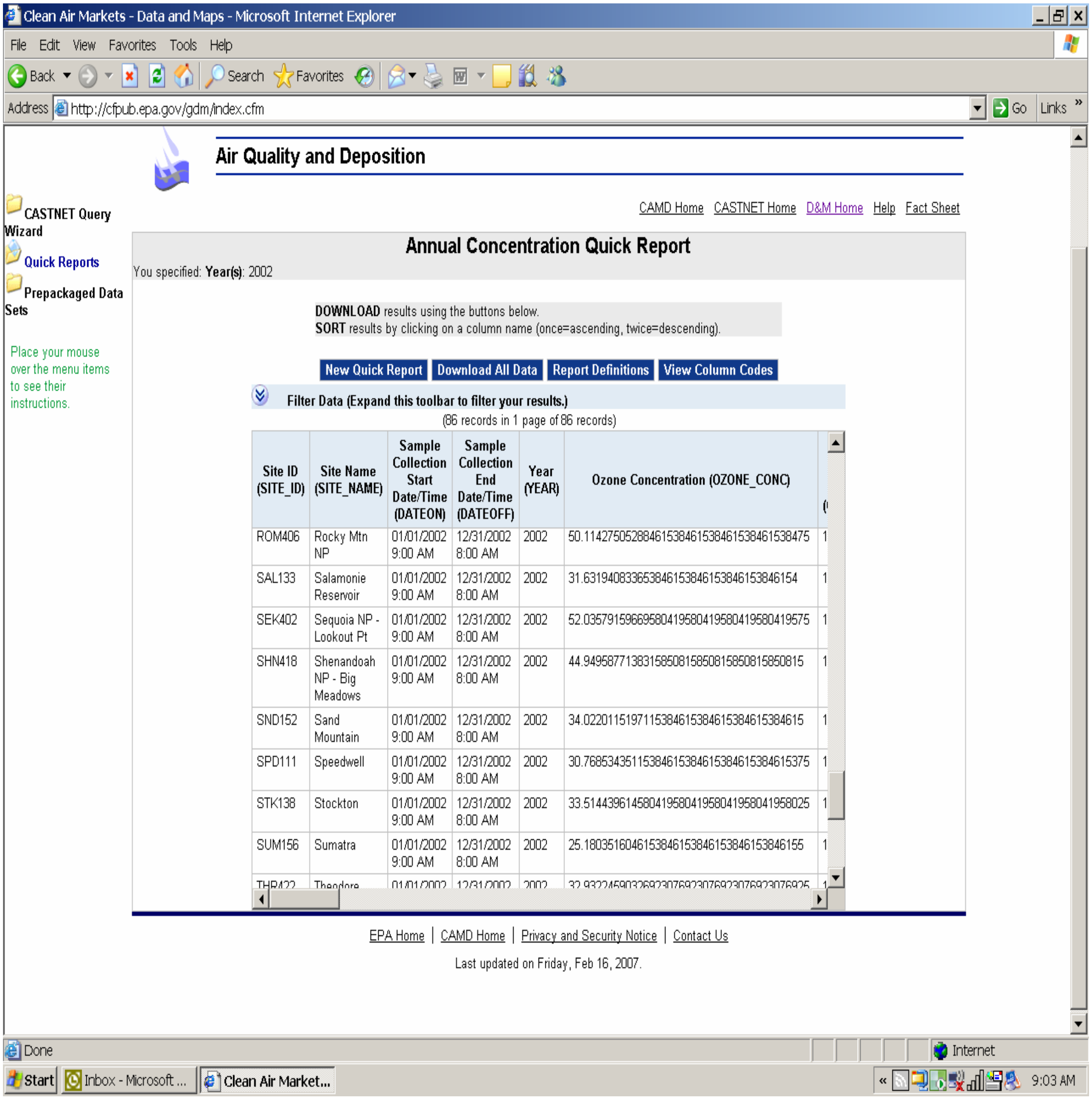
5.8 Unit 3 PM BART Determination

Due to insignificant predicted improvement in visibility and very high cost of the alternative control technologies, the existing ESP with emission limit of 0.3 lbs/MMBtu is considered BART for Unit 3 for particulate matter. However, NRG may voluntarily consider implementation of the wet ESP in future as part of multi-pollutant control in future in order to comply with the MPR and other future regulations. In such case, the visibility impact will be reduced from existing conditions.

Figures

Attachment 1

Background Ozone Concentration in Class I Areas



Site ID (SITE_ID)	Site Name (SITE_NAME)	Sample Collection Start Date/Time (DATEON)	Sample Collection End Date/Time (DATEOFF)	Year (YEAR)	Ozone Concentration (OZONE_CONC)	(
ROM406	Rocky Mtn NP	01/01/2002 9:00 AM	12/31/2002 8:00 AM	2002	50.11427505288461538461538461538461538475	1
SAL133	Salamonie Reservoir	01/01/2002 9:00 AM	12/31/2002 8:00 AM	2002	31.631940833653846153846153846153846154	1
SEK402	Sequoia NP - Lookout Pt	01/01/2002 9:00 AM	12/31/2002 8:00 AM	2002	52.03579159669580419580419580419580419575	1
SHN418	Shenandoah NP - Big Meadows	01/01/2002 9:00 AM	12/31/2002 8:00 AM	2002	44.949587713831585081585081585081585081 5	1
SND152	Sand Mountain	01/01/2002 9:00 AM	12/31/2002 8:00 AM	2002	34.022011519711538461538461538461538461 5	1
SPD111	Speedwell	01/01/2002 9:00 AM	12/31/2002 8:00 AM	2002	30.76853435115384615384615384615384615375	1
STK138	Stockton	01/01/2002 9:00 AM	12/31/2002 8:00 AM	2002	33.51443961458041958041958041958041958025	1
SUM156	Sumatra	01/01/2002 9:00 AM	12/31/2002 8:00 AM	2002	25.180351604615384615384615384615384615 5	1
THR422	Theodore	01/01/2002	12/31/2002	2002	32.93224590326923076923076923076923076925	1

340010005	Brigantine Wildlife Refuge, Nacote Creek; NJ

Ozone Monitoring Data 2002; Values in ppb

Monitor Id	Year	Except Data Flag	Interval	Unit	Exceed Std Pri	Method Cnt	Obs Cnt	Max1 Value	Max2 Value	Arith Mean
3400100054420101	2002	1	1	007	1	1	8617	.127	.107	.0569
3400100054420101	2002	2	1	007	1	1	8708	.127	.107	.0575
3400100054420101	2002	3	1	007	1	1	8708	.127	.107	.0575
3400100054420101	2002	4	1	007	1	1	8617	.127	.107	.0569
3400100054420101	2002	5	1	007	1	1	8617	.127	.107	.0569
3400100054420101	2002	6	1	007	1	1	8708	.127	.107	.0575
3400100054420101	2002	7	1	007	1	1	8617	.127	.107	.0569
3400100054420101	2002	1	W	007	9		8633	.101	.099	.0505
3400100054420101	2002	2	W	007	11		8728	.101	.099	.0511
3400100054420101	2002	3	W	007	11		8728	.101	.099	.0511

Source: USEPA AIRS Database

Attachment 2

Model Input Output Files (CD)

Attachment 3

Cost Determination for Alternative Control Technologies