Single Source Modeling to Support Regional Haze BART Modeling Protocol

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Lake Michigan Air Directors Consortium
Des Plaines, IL

Modeling may be necessary to support a decision by the States about which BART eligible sources "cause or contribute" to visibility impairment and are subject to BART. The threshold used to determine whether a source "contributes" to visibility impairment is 0.5 deciviews, or lower, which is suggested in U.S. Environmental Protection Agency (EPA) guidance (EPA, 2005). For the purposes of this analysis, the threshold used to determine whether a source "contributes" to visibility impairment is 0.5 deciviews. EPA guidance recommends CALPUFF for modeling single source visibility impacts at Class I areas (EPA, 2005).

POLLUTANTS

EPA guidance lists SO2, NOX, and primary particulate matter (PM) as visibility impairing pollutants (EPA, 2005). Emissions of SO2, NOX, and PM must be examined for source contribution to visibility impairment. EPA recommends using the CALPUFF modeling system. EPA guidance recommends the use of judgment to determine whether VOC, ammonia, or primary PM emissions contribute to visibility impairment (EPA, 2005). An additional modeling analysis will be performed to determine whether VOC, ammonia, and primary PM emissions need to be considered.

VISIBILITY IMPAIRMENT MODELING: SUBJECT TO BART

The list of BART-eligible sources in each state will include all 26 applicable source categories (i.e., both EGUs and non-EGUs). For EGUs, EPA states the CAIR rule will result in controls for electric generating units (EGUs) better than those achievable by the BART provision of the Regional Haze rule. Each State will need to make a policy decision to either accept this position or to impose BART controls on their EGUs. Since the CAIR rule regulates SOX and NOX emissions, some consideration for other EGU emissions including primary PM, VOC, and ammonia is necessary. An additional modeling analysis will be performed to determine whether VOC, ammonia, and primary PM emissions from all elevated point sources in the Midwest RPO States contribute to visibility impairment at Class I areas.

For non-EGUs, the options in the BART guideline for determining which sources need not be subject to BART will be considered. The three options are individual source attribution approach (i.e., CALPUFF modeling), use of model plants to exempt individual sources, and cumulative modeling to show that certain elevated point source emissions species do not contribute to visibility degradation at nearby Class I areas. All three options will be used here. Specifically, the following approach will be taken:

(1) Calculate the Q/d value for all sources based on actual emissions and minimum distance to a Class I area. (Note, the Q/d metric was

identified in EPA's proposed rule and is similar to the emissions-distance criteria suggested in the final rule.)

(2) Conduct individual source CALPUFF modeling for those sources with a Q/d value $\geq$ 5. (Note, the CALPUFF modeling conducted in response to EPA's proposed BART rule showed that the emissions-distance criteria associated with less than 0.5 dv visibility impacts on nearby Class I areas was consistent with a Q/d value of < 5.)

(3) Review the results of the new CALPUFF modeling to determine which sources have less than a 0.5 dv impact on nearby Class I areas and which can, therefore, be assumed to be exempt from the BART process.

(4) Also review the results of the new CALPUFF modeling for sources with a Q/d value between 5 and 20 to determine if 5 is an appropriate cut-off for exempting sources from the BART process.

(5) Cumulative modeling will also be performed with CAMx to determine if ammonia, VOC, and direct PM (fine and coarse mass) emissions can be exempt from the BART process.

CUMULATIVE VISBILITY IMPAIRMENT MODELING

A photochemical model (CAMx4) will be applied with the VOC, ammonia, and PM fine and coarse mass emissions "zeroed-out" from all point sources in the Midwest RPO States, both BART-eligible and non-BART-eligible. The "zero-out" run will include EGU and non-EGU point sources. The results of this run will be compared to a base run with these emissions included to determine if these emissions species impair visibility. This type of cumulative modeling is consistent with option 3 under the section on determining which sources are subject to BART (EPA, 2005). The CAMx4 modeling system is applied with the same inputs and parameters as used for the PM2.5 and regional haze SIP. CAMx4 will be applied for the 2002 calendar year at 36 km grid resolution.

SINGLE SOURCE VISIBILITY IMPAIRMENT MODELING: SUBJECT TO BART

The CALPUFF modeling system is used to estimate visibility impairment from single sources. CALPUFF consists of the plume transport model (CALPUFF), meteorological data pre-processors (CALMM5, CALMET), inorganic chemistry parameterization module (POSTUTIL), and post-processor (CALPOST) (Scire et al, 2000a; Scire et al, 2000b). The versions of the CALPUFF modeling system code used for this analysis are shown in Table 1.

Table 1. CALPUFF Modeling System Versions

	Version	Level
CALPUFF	5.771a	040716
CALPOST	5.51	030709
CALMET	5.53a	040716
CALMM5	2.0	021111
POSTUTIL	1.4	040818

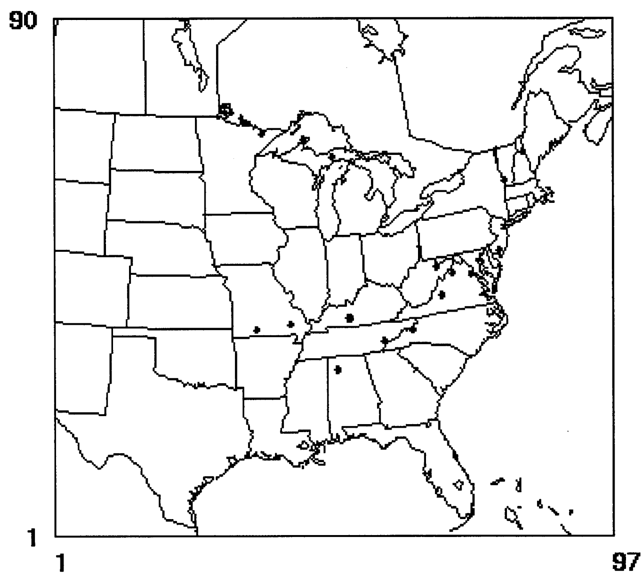
The modeling system is applied consistently with the EPA guidance recommendation of following the guidelines set forth in EPA's Interagency Workgroup on Air Quality Modeling (IWAQM) Phase 2 Summary Report and Recommendations for Modeling Long Range Transport Impacts (EPA, 2005; EPA, 1998). None of the BART eligible sources in the Midwest Regional Planning Organization are less than 50 km from a

Class I area so modeling analysis in addition to CALPUFF is not applicable. The IWAQM guidance states that less than 5 years of meteorological data may be used if a meteorological model using FDDA is used to supply data.

CALPUFF will be applied to each source for a 3 annual simulations, covering calendar years 2002 to 2004. CALPUFF will be applied using discrete receptor points covering the Class I areas with an approximate resolution of 1 km. POSTUTIL is used to re-partition nitrate into the gas or particulate phase depending on the estimated ammonia availability. This option has been shown to improve model performance (Scire et al, 2001). CALPOST is then applied to the POSTUTIL output for each group of Class I area receptors (shown in Figure 1 and in Table 3). CALPUFF, POSUTIL, and CALPOST are also run for 3 consecutive years for each source for gridded receptors that match the CALMET/CALPUFF domain shown in Figure 1. These runs allow for quality assurance and quality control by plotting the results for visual inspection. The results are checked for reasonableness of stack location, stack parameters, and emission rates. Each source is applied in CALPUFF for 3 years in a discrete receptor mode to meet regulatory requirements and for 3 years in a gridded receptor mode as a quality assurance and control measure.

The CALPUFF/CALMET modeling domain is a Lambert conformal grid projection centered at (97 W, 40 N) with true latitudes at 33 N and 45 N and origin at (-900 km, -1620 km). The horizontal domain consists of 97 36 km cells in the east-west direction and 90 36 km cells in the north-south direction (see Figure 1). The vertical atmosphere up to approximately 15 km is resolved with 16 vertical layers, most of which are in the boundary layer to appropriately resolve the diurnal fluctuations in boundary layer mixing depths.

Figure 1. Model Domain



Landuse and terrain data are extracted from the global datasets, USGS Composite Theme Grid landuse and USGS Digital Elevation Model terrain height, distributed with CALPUFF and match the horizontal grid specifications. Meteorological inputs to CALPUFF are output from a prognostic meteorological model using four-dimensional data assimilation. MM5v3.6 output is used to supply hourly meteorological data to CALPUFF.

Observation data is included in the ETA analysis fields used to initialize MM5 so additional assimilation of observational data in CALMET is redundant to the specific purpose of a prognostic meteorological model, which is to appropriately fill in the data around the surface monitoring network and sparse upper air monitoring network. The MM5 output used to support the BART CALPUFF modeling has extensive model performance evaluation and is used to support regional photochemical modeling applications for the ozone, PM2.5, and regional haze State Implementation Plans (Baker, 2004; Baker, 2005; Johnson, 2003).

Modeling options are set to be consistent with the IWAQM guidance. A few modifications to the suggested parameter settings are discussed in this section. For CALMET, several options were selected to use the MM5 output as input to CALMET rather than observation data; ICLOUD=3, IPROG=14, ITPROG=2, and IEXTRP=-1. Several options are selected in CALPUFF that differ from the IWAQM recommendations: the IDRY and IWET variables are set to 0 since dry and wet deposition flux output is not applicable for this analysis. The IPRTU variable is set to 3 to output specie concentrations in units of ug/m^3 to be consistent with measured regional concentrations.

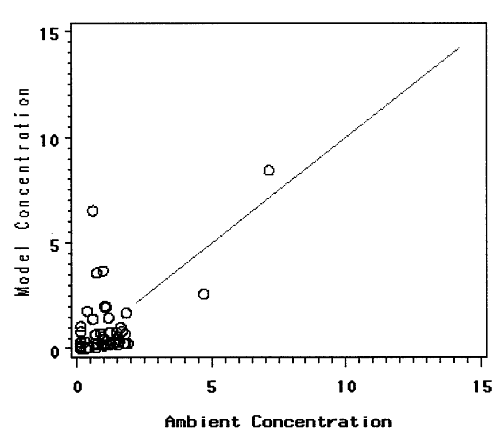
CALPUFF requires the input of ozone (O3) and ammonia (NH3) concentrations as a monthly background value applicable for the entire modeling domain. Seasonal domain averaged concentrations of each will be obtained from an annual 2002 calendar year CAMx4 simulation. These values are shown in Table 2.

Table 2. Domain Seasonal Average Concentrations (ppb)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
O3 (ppb)	31	31	31	37	37	37	33	33	33	27	27	27
NH3 (ppb)	.3	.3	.3	.5	.5	.5	.5	.5	.5	.5	.5	.5

CAMx4 prediction of ammonia at the rural Illinois site in Bondville shows good agreement between model predictions and ambient observations. A scatter plot showing the prediction-observation pairs over the entire calendar year of 2004 is shown in Figure 2.

Figure 2. CAMx4 model and ambient ammonia Predictions at Bondville, Illinois



SOURCE SPECIFIC INPUTS: EMISSIONS and STACK PARAMETERS

States will use the 24-hr maximum emissions rate between 2002 and 2004. If this data is not available, then a short term "allowable" or "potential" emission rate of emissions between 2002-2004 will be used. If neither of these types of emission rates is available, then the highest actual annual emissions divided by hours of operation of NOX, SOX, and primary PM between 2002 and 2004 will be applied in CALPUFF.

EPA recommends the States should determine the specific stacks that BART process emissions will exit and use stack information specific to those stacks (EPA, 2005b).

CLASS I AREA RECEPTORS

The receptors used to determine visibility impacts are taken from the National Park Service's Class I area receptor index (NPS, 2005). The receptors "should be located in the nearest Class I area with sufficient density to identify likely visibility effects" according to the BART modeling guidance (EPA, 2005). The spatial resolution of the discrete receptors is not changed in any way from the NPS files. Table 3 shows the list of Class I areas and the total number of discrete receptors covering the Class I area used as the receptor field in CALPUFF.

Table 3. Class I Receptor areas and total discrete rectors

Boundary Waters Canoe Area	MN	856
Brigantine National Wildlife Refuge	NJ	16
Dolly Sods /Otter Creek Wilderness	WV	187
Great Gulf Wilderness	NH	38
Great Smoky Mountains National Park	TN	736
Hercules-Glades	MO	80
Isle Royale National Park	MI	966
James River Face	VA	52
Linville Gorge	NC	66
Lye Brook Wilderness	VT	103
Mammoth Cave National Park	KY	302
Mingo	MO	47
Seney	MI	173
Shenandoah National Park	VA	298
Sipsy Wilderness	AL	148
Voyageurs National Park	MN	366

CALPUFF OUTPUT: POST PROCESSING and INTERPRETATION

The light extinction equation will use the monthly average relative humidity (RH) rather than the daily average humidity as detailed in the BART modeling guidance (EPA, 1998; FLAG, 2000). This necessitates using the CALPOST background light extinction option 6, which computes light extinction from speciated PM measurements with a monthly RH adjustment factor. These Class I area centroid specific monthly RH adjustment factors are taken from Table A-3 of the EPA's "Regional Haze: Estimating Natural Visibility Conditions under the Regional Haze Rule: Guidance Document." (EPA, 2003).

The daily visibility metric for each receptor is expressed as the change in deciviews compared to natural visibility conditions as outlined in the IWAQM guidance (EPA, 1998). Natural visibility conditions, the 20% best days, for Class I areas used in this analysis are found in Appendix B of EPA's Guidance for Estimating Natural Visibility Conditions under the Regional Haze Rule (EPA, 2003). The 20% best days for each Class I area are listed in Appendix B in deciviews and not as chemically speciated constituents of the light extinction equation, which are needed for CALPOST option 6. Annual background concentrations for the eastern United States are given in the Guidance for Estimating Natural Visibility Conditions in Table 2-1 (EPA, 2003). These values are scaled back to lower concentrations until the Class I area specific natural visibility metric is produced (North Dakota Department of Health, 2005). This scaling procedure is done for each Class I area and uses an annual average fRH calculated from the 12 monthly site specific fRH values mentioned in the first paragraph of this section (EPA, 2003).

The annual average Class I area specific natural conditions are given in deciviews, so they must be converted to light extinction.

Natural conditions (1/Mm) = 10*exp(natural conditions in deciviews/10)

Second, the chemically speciated natural background concentrations for the eastern United States are scaled to equal the site specific natural background light extinction value.

Natural conditions in 1/Mm = 3*fRH*[ammonium sulfate]*X + 3*fRH*[ammonium nitrate]*X + 4*[OC]*X + 10*[EC]*X + 1*[SOIL]*X + 0.6*[CM]*X + [$\beta_{(Raleigh)}$]

The bracketed concentrations are expressed as ug/m3. The fRH values represent annual average fRH calculated from the 12 monthly site specific fRH values mentioned in the first paragraph of this section (EPA, 2003). Solving for X gives the dimensionless scaling factor which is applied to each of the chemically speciated natural background concentrations given for the eastern United States. The natural background values and scaling factors used for each Class I area are shown in Table 4.

Table 4. Scaled natural background values by Class I area

Class I Area	Nat. Back. deciview	Nat. Back. 1/Mm	Scaling Factor	Annual average fRH	Amm. Sulfate	Amm. Nitrate	Organic Carbon	Elemental Carbon	Soil	Coarse Mass
BOWA	3.53	14.233	0.39	2.93	0.089	0.038	0.539	0.008	0.192	1.155
BRIG	3.60	14.333	0.39	3.05	0.090	0.039	0.546	0.008	0.195	1.169
DOSO	3.64	14.391	0.39	3.20	0.090	0.039	0.546	0.008	0.195	1.169
GRGU	3.63	14.376	0.39	3.13	0.090	0.039	0.547	0.008	0.195	1.172
GRSM	3.76	14.564	0.40	3.46	0.091	0.040	0.555	0.008	0.198	1.188
HEGL	3.59	14.319	0.39	3.13	0.089	0.039	0.540	0.008	0.193	1.157
ISLE	3.54	14.248	0.39	2.90	0.089	0.039	0.542	0.008	0.194	1.161
JARI	3.56	14.276	0.39	3.04	0.089	0.038	0.539	0.008	0.192	1.155
LIGO	3.75	14.550	0.39	3.54	0.090	0.039	0.549	0.008	0.196	1.176
LYBR	3.57	14.290	0.39	2.99	0.089	0.039	0.543	0.008	0.194	1.164
MACA	3.85	14.696	0.41	3.36	0.095	0.041	0.575	0.008	0.206	1.233
MING	3.59	14.319	0.39	3.14	0.089	0.039	0.539	0.008	0.193	1.156
SENE	3.69	14.463	0.39	3.30	0.090	0.039	0.550	0.008	0.196	1.178
SHEN	3.57	14.290	0.38	3.19	0.088	0.038	0.533	0.008	0.191	1.143
SIPS	3.71	14.492	0.39	3.43	0.090	0.039	0.547	0.008	0.195	1.172
VOYA	3.41	14.064	0.38	2.71	0.087	0.038	0.528	0.008	0.188	1.131

The visibility degradation beyond natural conditions expressed in deciviews is kept for each Class I area and ranked over the length of the modeling simulation. The criteria used to determine if a source is "contributing" to visibility impairment is the 98th percentile that is equal to .5 deciviews for MRPO States using a maximum 24-hour emission rate and the peak value that is equal to .5 deciviews for MRPO States using an actual 24-hour emission rate. The 98th percentile is interpreted as any source with more than 21 days of visibility impairment over the 3 year modeling period or 7 days of visibility impairment in any one of the 3 years modeled is "contributing" to visibility impairment. The peak value is interpreted as any source with more than 1 day of visibility impairment over the 3 year modeling period is "contributing" to visibility impairment.

The gridded receptor run will be post processed through CALPOST for plotting purposes. The plots show the number of days at each receptor that have 24-hr average 1% degradation in light extinction (1/Mm) over background conditions. This is approximate, but not equal, to 0.5 deciview degradation over background conditions. These plots allow for a qualitative visual inspection of the extent impact over the region.

VISIBILITY IMPROVEMENT DETERMINATION

Once a source is considered subject to BART the visibility improvement determination requires additional single source modeling. CALPUFF will be used to determine the visibility improvement at Class I area receptors from the potential BART control technology applied to the source. Post-control emission rates are calculated as a percentage of the pre-control emission rates (EPA, 2005).

The post-control CALPUFF simulation will be compared to the pre-control CALPUFF simulation by the change in the value of the highest degradation in visibility over natural conditions between the pre-control and post-control simulations (EPA, 2005). Further information on the sources and control levels to be used in this additional modeling will be provided later.

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Appendix G

BEST AVAILABLE RETROFIT TECHNOLOGY (BART) Engineering Analysis

P.H. Glatfelter Company – Chillicothe Facility

Chillicothe, Ohio

Prepared by: **BE&K Engineering**

November 2007

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Attachments

1.0 Introduction

The P.H. Glatfelter Company – Chillicothe Facility (Glatfelter) is a pulp and paper mill located in Chillicothe in south central Ohio. The mill produces specialty grades of paper, including carbonless, book, and uncoated papers. The facility has a bleached kraft pulp mill which supplies part of the raw material to its paper machines. The facility has six steam generating boilers – two natural gas package boilers, one recovery boiler firing spent pulping liquor, one power boiler firing biomass, and two power boilers firing pulverized coal. The flue gas from the two coal-fired power boilers flows through separate electrostatic precipitators, then is combined and exhausted through a 475 foot concrete stack. See Attachment #1 for an area layout of the existing boilers and precipitators.

The Federal Environmental Protection Agency (EPA) has proposed guidelines for implementation of the Best Available Retrofit Technology (BART) requirements under the regional haze rule. The regional haze rule requires states to submit a state implementation plan (SIP) to address regional haze visibility impairment in 156 federally-protected parks and wilderness areas. The mill qualifies as a major source under a number of different Clean Air Act regulatory programs, including Federal and State of Ohio programs. Several of the emission sources in the mill were originally constructed between 1962 and 1977. As a result of the installation dates, as well as the fact that the mill is one of the 26 major sources categories listed in the BART regulation, Glatfelter is subject to the BART requirements. The Chillicothe mill impacts a Class I federally-protected area. The BART-eligible sources at the Glatfelter Chillicothe mill are the two pulverized coal boilers: No. 7 Coal Boiler (B002) and No. 8 Coal Boiler (B003).

The BART analysis concentrates on sulfur dioxide (SO_2), NO_x, and particulate emissions. The initial modeling completed by Ohio EPA for No. 7 and No. 8 Coal Boilers indicated that a minimum of 58% sulfur dioxide reduction will be required, while floor technology NO_x control (i.e., low NO_x burners or equivalent) is required. Since the boilers are already equipped with NO_x control, only brief mention will be given for a control technology's impact on NO_x.

No. 7 Coal Boiler is an Alstom (Combustion Engineering) VU-40 type sub-critical, natural circulation balanced draft steam generator designed for 300,000 lb/hr main steam flow at superheater outlet conditions of 875 psig and 850°F. This is a tangentially fired boiler that burns pulverized coal. The boiler is equipped with NO_x emission controls consisting of an Alstom Power low NO_x concentric firing system and a vane close-coupled overfire air compartment. This approach has produced equivalent results to low NO_x burners. Additionally, the flue gases flow through an Environmental Elements Dry Precipitator.

No. 8 Coal Boiler is an Alstom (Combustion Engineering) VU-40 wall-fired sub-critical, natural circulation balanced draft steam generator designed for 400,000 lb/hr main steam flow at superheater outlet conditions of 1475 psig and 950°F. The boiler fires pulverized coal in four Advanced Combustion Technology low-NO_x staged combustion burners. Additionally, the flue gases flow through an Environmental Elements Dry Precipitator.

For the BART-eligible sources, this engineering analysis is being conducted and includes the following steps:

- **Identify all retrofit control options** including pollution prevention techniques (i.e., low-NO_x burners); add-on controls; enhancements to existing controls; or a combination of the above. Source re-design or fuel switching is not required.
- **Evaluation of technical feasibility** of retrofit control options.
- **Evaluate cost impacts –** assess both capital and annualized costs.
- **Evaluate energy and non-air environmental impacts** where direct energy penalties or benefits are quantified and factored into the cost calculations.
- **Useful life of source –** only impacts analysis if useful life of the source is less than typical amortization period. Both boilers are anticipated to be in operation for as long as the amortization period of 10 years from installation of the control devices.

2.0 NO_x Retrofit Control

The mill installed NO_x emission controls consisting of an Alstom Power low NO_x concentric firing system and a vane close-coupled over fire air compartment on No. 7 Coal Boiler in 2003 for compliance with the NO_x Budget Program. This approach has produced equivalent results to low NO_x burners. For this tangentially fired boiler, typical low-NO_x burners are technically infeasible.

NO_x emission controls were installed on No. 8 Coal Boiler in 2001, also for compliance with the NO_x Budget Program. No. 8 Coal Boiler fires pulverized coal in four Advanced Combustion Technology low-NO_x staged combustion burners. Due to the furnace geometry and furnace cavity depth, additional NO_x reductions would adversely affect the boiler operations.

Currently, Glatfelter employs the use of combustion control methods during the ozone season to reduce the amount of NO_x from No. 7 Coal Boiler and No. 8 Coal Boiler to comply with the mill's NO_x Budget Program ozone season allowances. Air to the boilers is adjusted and the boilers' steaming rates are reduced during the ozone season.

The initial modeling by Ohio EPA indicated that additional NO_x reductions have negligible impact the visibility at the Class I federally-protected area. Therefore, the current low-NO_x burners or equivalent technology in operation would satisfy BART requirements.

3.0 SO_2 Retrofit Control

SO_2 emissions from the No. 7 Coal Boiler and No. 8 Coal Boiler are a result of the oxidation of sulfur contained in the coal and fuel oil combusted in the boiler. The majority of the sulfur in the fuel is oxidized to SO_2. A small percentage of the sulfur is oxidized to SO_3 that reacts with the water vapor in both the flue gas and in the atmosphere to form H_2SO_4. A list of available control technologies with the potential for controlling SO_2 emissions from the boilers was formulated.

3.1 Potential Retrofit Control Options

The following retrofit control options for SO_2 emissions were considered:

- **Wet Electrostatic Precipitator (WESP) -** Install WESP on combined flue gas streams.
- **Wet Flue Gas De-Sulfurization (FGD) -** Install wet FGD on individual flue gas streams and install new stacks.
- **Semi-Dry Flue Gas De-Sulfurization ahead of existing electrostatic precipitators -** Duct individual flue gas streams to dry FGDs and then to both precipitators, utilizing the existing stack.
- **Semi-Dry Flue Gas De-Sulfurization with baghouse after existing electrostatic precipitators -** Duct individual flue gas streams to dry FGDs and then to new baghouse, utilizing the existing stack.
- **Over-fire Air (OFA) and Sorbent Injection System (SIS)-** Install OFA and SIS systems for in-furnace SO_2 absorption with a new fan and auxiliaries.

The following fuel switching and re-design options were briefly considered but are not required to be part of the BART Engineering analysis:

- **Change coals -** Change to nominal 2% sulfur coal. This would require storage pile/bunker modifications.
- **Change fuels to biomass -** Requires additional storage facilities, conveyor system, significant modifications to burners, and potential changes to precipitators.
- **New Bubbling Fluidized Bed Boiler (BFB) to replace power boilers -** Install new BFB capable of burning coal, biomass, etc.
- **Coal Gasification System -** Gasify coal and fire de-sulfurized gas in No. 7 and No. 8 Boilers.

3.2 Wet Electrostatic Precipitator

The key components of the installation of a Wet Electrostatic Precipitator (WESP) on the flue gases exiting the Induced Draft (ID) fans are as follows:

- Inlet Gas Conditioning System – Utilizes atomizing nozzles to provide an ultra fine conditioning spray at the inlet to the WESP. The conditioning spray promotes particle agglomeration and growth while at the same time providing the proper amount of liquid necessary to irrigate the collection surfaces. The alkaline fluid would be added at this point.

- Gas Flow Distribution System – Multiple perforated plates are utilized at the gas inlet to the precipitator to equally distribute the flue gas to the collection tubes. Typically, large diameter holes are used to prevent buildup of particulate, which causes pluggage. The result is even distribution of the gas across the tube bundle.
- Downflow Tubular Design – The top inlet design allows the flue gas to flow downward through the collection tubes. The collected liquid and particulate droplets create a self-forming falling film of liquid that flows by gravity, irrigating the inside surfaces of the tube walls (collecting surface), which provides continuous cleaning. The common wall tube design provides high structural strength and small footprint.
- High Voltage System – The incoming particles are given a strong negative charge by a high-intensity ionizing corona produced by high voltage electrodes. The insulator compartments are purged with filtered, heated air to keep the insulators clean and dry. As the gas flows through the collection tubes, the action of the electric field on the charged particles causes them to migrate to the grounded walls of the tubes where they accumulate.
- Flushing System – The high voltage plenum is equipped with a flushing header that provides an intermittent flushing spray to prevent any buildup of particulate on the high voltage frame and collection tubes. The self-washing action of the water film that falls down the inside of the tubes removes the collected material to a discharge drain. A slipstream of the fluid is sewered, while the majority of the fluid is recycled.

The WESPs would consist of multi-compartments, such that selected compartments could be taken off-line for maintenance. The downflow design requires a booster fan to push the flue gases up the stack.

Since the flue gases are saturated and cool, a new stainless steel stack would be installed, properly sized for the volume of colder flue gas and at a height determined by dispersion requirements.

The WESP may be located on a new steel structure located above the existing package boilers. An alternate to this design would be to bypass the existing ESPs and duct the flue gases to the WESPs – however this would require replacing the ID fans.

3.3 Wet Flue Gas De-Sulfurization

Each boiler's ID Fan will draw the gas from the precipitator outlet and direct it into the absorber. The absorber consists of an open spray tower.

The spray tower is a vertical vessel with a radial inlet, where the SO_2-laden gas is treated in several spray zones. The liquid drains to the bottom reservoir, where it is recycled to the spray zones using recycle pumps. The treated gas exits through the top of the vessel.

The gas continues vertically upwards through the spray zones, which provide the necessary contact surface for absorption of the acid gas. The spray headers are designed with large orifice spray nozzles, which are positioned such that the absorber cross-sectional area is completely covered and no gas can escape without coming into intimate contact with the liquid.

After passing through the spray zones, the gas enters a chevron-type mist eliminator, which eliminates droplet carry-over in the tower outlet. In order to remove possible build up of reaction salts on the mist eliminator, a wash header is located below the unit. The wash header provides a powerful spray triggered by the plant DCS. The wash is intermittent and covers only part of the mist eliminator at the same time.

The absorbing acid gas, or the quantity of gas transferred to the liquid phase, is proportional to the surface area. The collective surface area is significant due to the large number of extremely fine droplets.

The wet FGD would be placed downstream of the ID fans and may be physically located on a new steel structure above the existing package boilers.

In order to attain the required absorption of SO_2, dilute caustic or possibly sodium carbonate solution is added to the top spray header, so that the gas leaving the FGD sees the highest pH.

A certain amount of liquid is removed from the recycle loop in order to maintain a specified amount of dissolved solids in the recycle. This blow-down pipe is connected to the discharge side of the recycle pumps and is regulated by a density controller.

Evaporation takes place in the FGD, and in order to compensate for the liquid removed from the FGD in the bleed and by evaporation, a liquid level controller in the bottom of the absorber adds water via a control valve to maintain the pre-determined level.

The gases from No. 7 and No. 8 FGDs will be combined and flow through a new stainless steel stack. The new stack will be appropriately sized for the new gas conditions and required dispersion.

See Attachment #2 for a possible layout of the wet FGD system.

3.4 Semi-Dry De-Sulfurization Before Existing Precipitators

The flue gases from each boiler will be re-directed to a spray-dry absorber (SDA) vessel which may be located on a new structure above the existing package boilers. After passing through the vessel, the gases will be directed to the existing precipitators, which would require some modifications, and then ducted to the existing ID fan. From the ID fans, the gases will be combined and flow through the existing stack.

The SDA vessel consists of a vertical-down flow chamber, designed to provide optimal gas and liquid spray interactions. This allows for adequate retention time for evaporative cooling and lime slurry spray-dry absorption of acid gases.

The reagent used is a slurry of hydrated lime [$Ca(OH)_2$] that is mixed with a dilution water stream. The total volume of the spray is carefully controlled to maintain the SDA outlet temperature set point, while the amount of lime injected is separately controlled to maintain sulfur dioxide (SO_2) control.

All of the liquid sprayed evaporates completely as it travels through the tower, leaving only dry reagent products at the discharge. The partially reacted lime powder and ash is then transported from the SDA vessel in the flue gas to the existing precipitators.

The treated flue gases would be directed to the ID fan and then up the existing stack.

See Attachment #3 for a possible layout of the semi-dry FGD system before the existing precipitators.

3.5 Semi-Dry FGD after Precipitators

This application is similar to Semi-Dry De-Sulfurization before the precipitators except that the flue gases will flow through the precipitators to the ID fan. The gases will flow into the semi-dry absorbers and then into baghouses and finally to the existing stack.

This system will require an additional ash handling system for particulate collected in the baghouse. This will be the reaction products of the absorbed gases and the lime.

3.6 Overfire Air and Sorbent Injection System

A typical OFA installation will have a booster fan to supply the high velocity air to the OFA boxes. The air will be supplied from the hot side of the air heater. There will be several OFA boxes that will be placed at different levels of the boiler. These boxes will be placed asymmetrically on opposite sides of the boiler. Each OFA box will have a damper to control the amount of high velocity air going to the box. The design of the OFA boxes and the placement of each OFA box are determined through the use of a Computational Fluid Dynamics (CFD) model.

Although No. 7 Coal Boiler already has an overfire air system, the above suggested OFA design is required to maximize the efficiency of the SIS system. Therefore, the existing overfire air system on No. 7 Coal Boiler will be de-commissioned.

The volume inside the furnace is set in rotation via special asymmetrically placed air nozzles. The combustion gases mix well with the added air, making a combustion gas swirl. This generates turbulence and rotation in the entire furnace.

Rotation prevents laminar flow and the whole volume of the furnace can be used more effectively for the combustion process. The OFA swirl reduces the maximum temperature of the flames and increases heat absorption, which in turn improves the overall efficiency of the boilers.

With the OFA technique, surplus air can be reduced without increasing unburned fuel or other unwanted substances. The combustion air is mixed more effectively. The result is less cooling of the furnace from unused combustion air; thereby, increasing efficiency.

Some of the features of the OFA system are:

- Less temperature variation in the cross-section of the furnace.
- A more even distribution of combustion products in the cross-section of the furnace.
- Rotary mixing dramatically reduces fly ash (i.e., unburned content in the flue gas).
- Less surplus air (O_2) which means higher overall efficiency.

OFA prepares the furnace for the effective mixing of chemicals in the furnace. The SIS system has been developed for optimum reduction of unwanted substances, such as NO_x and SO_2. The same kind of asymmetrically placed air nozzles are used in the SIS technique as in the OFA system.

3.7 Switch to Low Sulfur Coal Supply

Although fuel switching options are not required to be a part of the BART Engineering Analysis, the option of switching to a low sulfur coal supply was considered. SO_2 emissions from No. 7 and 8 Coal Boilers are directly related to the sulfur content of the fuels combusted. Switching to a lower sulfur coal supply could potentially reduce SO_2 emissions from the boilers. Glatfelter researched coal suppliers with a lower sulfur content, which is still within the mill's heating value and ash specifications. The current southern Ohio coal supplied to the mill averages approximately 4.5% sulfur content. A lower sulfur coal could be supplied from Northeastern Ohio or Eastern Kentucky. The sulfur content of that coal would be approximately 2%. However, due to a lower heating value (BTU/pound), the lower sulfur coal is estimated to replace Glatfelter's current coal at a ratio higher than 1:1. Switching to a lower sulfur coal is estimated to be approximately a 50% reduction in SO_2 emissions.

This option would also require modifications to the coal handling system. Currently, coal is supplied by truck from local Southern Ohio coal suppliers. The Eastern Kentucky coal may be supplied by railroad, which would require a railcar unloading system. The increased distance between the mill and either of the coal suppliers would also require a larger storage pile at Glatfelter. The mill currently burns approximately 800-900 tons per day, and approximately a two to three day supply of coal is maintained on-site. The storage size would need to be increased to prevent disruptions to paper production in the event of delays in coal deliveries.

The use of low sulfur coal may be a technically feasible option; however, the mill does not anticipate that it would meet the BART model level of 58% SO_2 reduction indicated to be necessary by the CALPUFF visibility modeling.

4.0 Evaluation of Technical Feasibility

The options discussed in Section 2 were evaluated with the following identified advantages and disadvantages:

4.1 WESP

4.1.1 Advantages

- Effective control of sub-micron-sized particulate emissions
- Removal of condensable matter
- Higher removal efficiency than a wet FGD alone
- Wash water can be re-used
- Good control of acid gas emissions
- Insensitivity to variations in particulate composition
- Low pressure drop
- Commercially accepted
- 90% SO_2 removal

4.1.2 Disadvantages

- Lower flue gas temperature will decrease dispersion of gases
- A new stack will be required for proper dispersion and corrosion control.
- High energy use – additional fan requirement
- Space considerations will result in construction difficulties (potential placement of the units above the package boilers)
- Not as commercially accepted as flue gas de-sulfurization (FGD) only

4.2 Wet FGD

4.2.1 Advantages

- Wash water can be re-used
- Low pressure drop
- Commercially accepted proven technology
- 90% SO_2 removal
- Typical treatment technique

4.2.2 Disadvantages

- Lower flue gas temperature will decrease dispersion of gases

- Visible plume
- More stainless steel ducting will be required
- A new stack will be required.
- Higher energy use – additional fan (No. 8 Coal Boiler) requirement
- Space considerations will result in construction difficulties (potential placement of the units above the package boilers – see Attachment #2)
- Uses caustic soda for alkali vs. other more plentiful reagents such as lime or limestone

4.3 Semi-Dry FGD before Existing Precipitators

4.3.1 Advantages

- 90% SO_2 removal
- Best use of existing precipitators
- Dryer flue gases in the stack

4.3.2 Disadvantages

- Long duct runs
- Need to consider volume of cooled, dry flue gas in existing stack and implications of this on dispersion. May require new stack, but this will require further investigation.
- Space considerations will result in construction difficulties and increased cost (potential placement of the units above the package boilers – see Attachment #3)

4.4 Semi-Dry FGD after Precipitators

4.4.1 Advantages

- 90% SO_2 removal
- Improved particulate control

4.4.2 Disadvantages

- High energy use – booster fan required for added delta-P across baghouse
- Complex operation with two particulate control devices
- Additional ash handling required from baghouse
- Need to consider volume of cooled, dry flue gas in existing stack and implications of this on dispersion. May require new stack, but this will require further investigation.
- Space considerations will result in construction difficulties (potential placement of the units above the package boilers)

4.5 Overfire Air and Sorbent Injection System

4.5.1 Advantages

- Proven at 60% removal rates.
- Improved combustion efficiency
- Dry stack – no additional modifications to stack will be necessary
- Better constructability – does not require construction over package boilers
- Additional NO_x reduction

4.5.2 Disadvantages

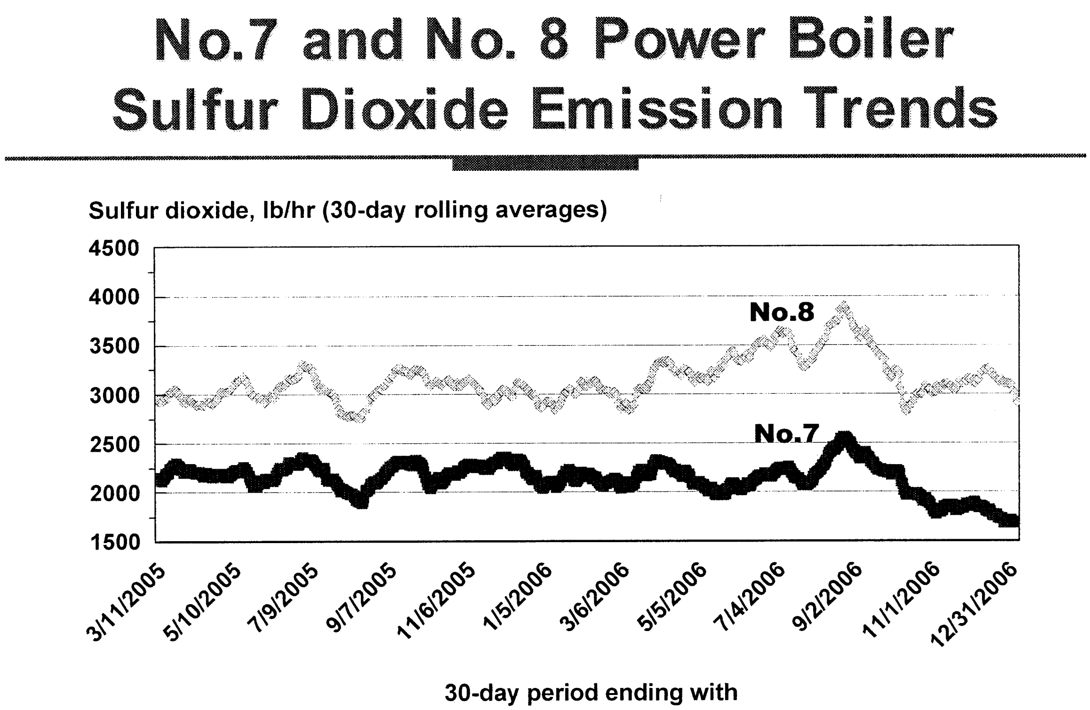
- Will not achieve 90% removal rates

4.6 Sulfur Dioxide Emission Rates

4.6.1 Current Emission Rate

The following graph illustrates the current No. 7 and No. 8 Coal Boiler SO_2 emission rate trends based on fuel analysis:

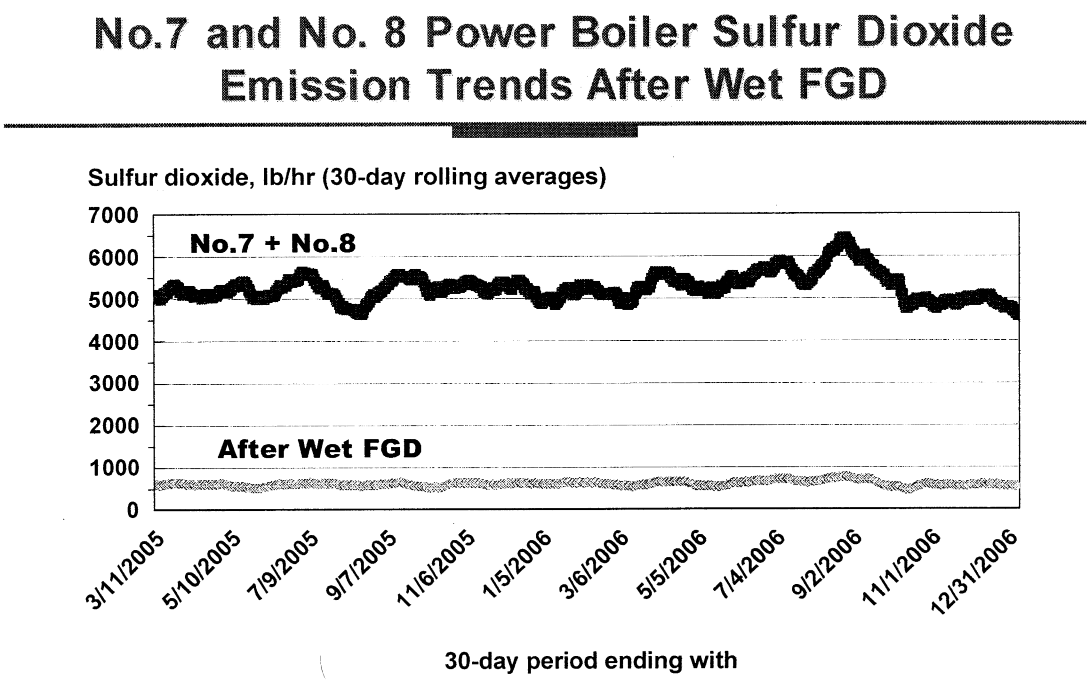
Figure 4-1



4.6.2 Emission Rate Estimate after Wet FGD

The following graph illustrates the estimated sulfur dioxide emission rate after wet FGD at an average 90% removal rate:

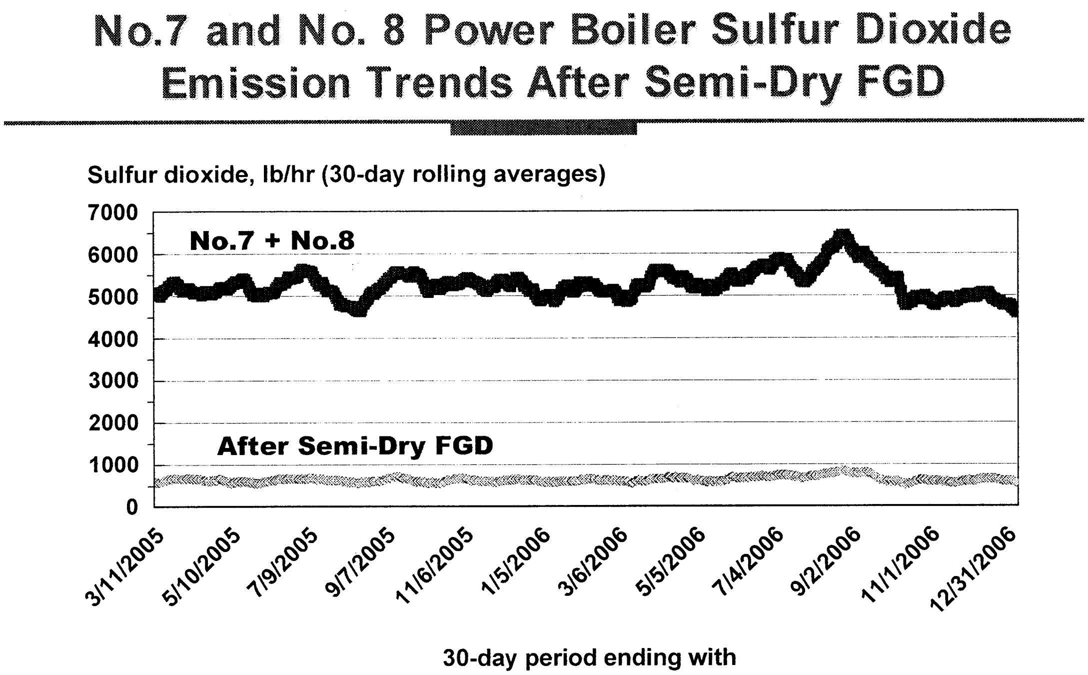
Figure 4-2



4.6.3 Emission Rate after Dry FGD

The following graph illustrates the estimated sulfur dioxide emission rate after semi-dry FGD at an average 90% removal rate:

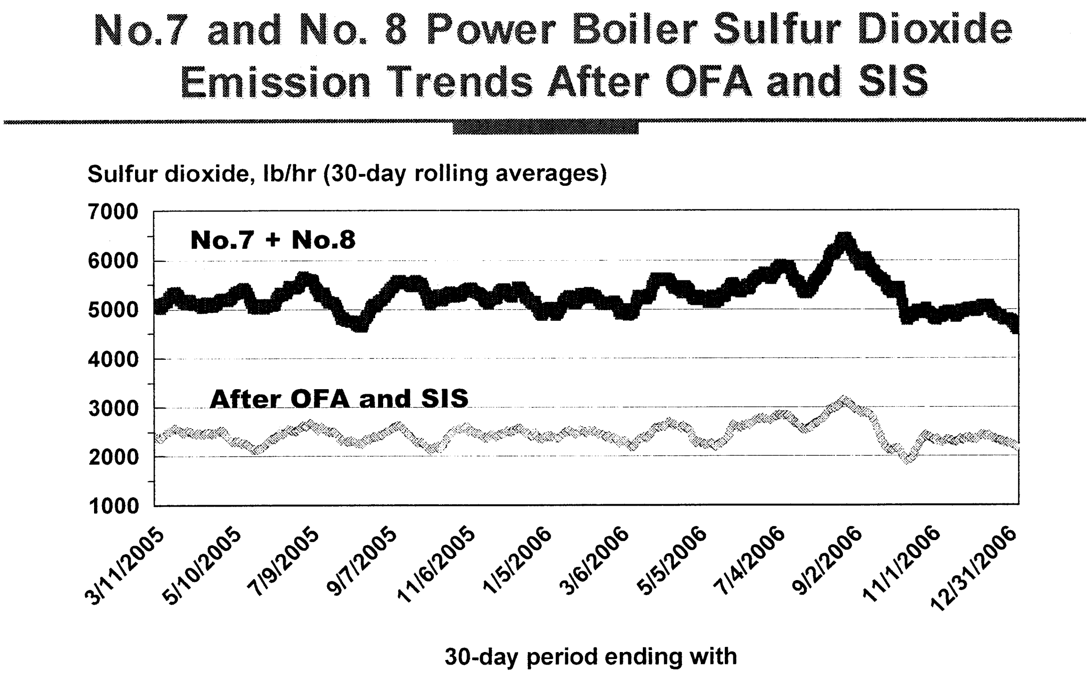
Figure 4-3



4.6.4 Emission Rate after OFA and SIS

The following graph illustrates the estimated sulfur dioxide emission rate after OFA and SIS installation at a nominal 60% removal rate:

Figure 4-4



5.0 Cost Impact Evaluation

5.1 Introduction

The WESP and semi-dry FGD with baghouse after precipitators were both discarded. Both required more space than either the wet FGD or semi-dry FGD. Furthermore, neither device would result in appreciably more SO_2 removal or less expensive removal.

Therefore, the following control technology options were investigated further:

- Wet FGD
- Semi-dry FGD before existing precipitators
- OFA and SIS

5.2 Wet FGD

5.2.1 Total Installed Cost

The following table lists the equipment required for the wet FGD system:

Table 4-1
Wet FGD System Scope

Boiler	Scope
No. 7 Blr	Wet FGD System
	Ductwork, including insulation, expansion joints and supports
	Stack – new common stack with No. 8 PB
	ID Fan - new wheel
	Piping, Instrumentation, Electrical
	Steel and Foundations
No. 8 Blr	Wet FGD System
	Ductwork, including insulation, expansion joints and supports
	ID Fan - new wheel – new motor
	Piping, Instrumentation, Electrical
	Steel and Foundations

Including contingencies and design engineering, the estimated cost for the wet flue gas de-sulfurization system is estimated to be $26,000,000.

5.2.2 Operating and Maintenance Costs

The following table is an estimate of the operating and maintenance costs, including other environmental costs:

Table 4-2 Wet FGD Annual Operating and Maintenance Costs		
Annual Cost	**Cost in Thousands**	
	No. 7 Coal Boiler	**No. 8 Coal Boiler**
Chemical – caustic soda @ $200/ton	$3,155	$5,125
Power @ $0.05/kwh	$48	$64
Landfill costs @ $20/ton	$324	$500
Maintenance	$200	$300
Total	**$9,716**	

5.3 Semi-Dry FGD

5.3.1 Total Installed Cost

The following tables lists the equipment required for the semi-dry FGD system:

Table 4-3
Semi-Dry FGD System Scope

Boiler	Scope
No. 7 Blr	Semi-dry FGD System Including Lime Handling
	Ductwork, including insulation, expansion joints and supports
	Precipitator upgrade - minimal allowance
	ID Fan - new wheel
	Ash handling system allowance
	Piping, Instrumentation, Electrical
	Steel and Foundations
No. 8 Blr	Semi-dry FGD System Including Lime Handling
	Ductwork, including insulation, expansion joints and supports
	Precipitator upgrade - major allowance
	ID Fan - new fan and motor
	Ash handling system
	Piping, Instrumentation, Electrical
	Steel and Foundations

Including contingencies and design engineering, the cost for the semi-dry FGD system is estimated to be $34,300,000.

5.3.2 Operating and Maintenance Costs

The following table is an estimate of the operating and maintenance costs, including other environmental costs:

Table 4-4 Semi-Dry FGD Annual Operating and Maintenance Costs		
Annual Cost	**Cost in Thousands**	
	No. 7 Coal Boiler	**No. 8 Coal Boiler**
Chemical – caustic soda @ $200/ton	$1,796	$2,928
Power @ $0.05/kwh	$116	$155
Landfill costs @$20/ton	$566	$895
Maintenance	$200	$300
Total	**$6,956**	

5.4 Overfire Air and Sorbent Injection System

5.4.1 Total Installed Cost

The following table lists the equipment required for the OFA/SIS system:

Table 4-5
Overfire Air and Sorbent Injection System Scope

Boiler	Scope Item
No. 7 Blr	Hot side OFA/SIS includes lime handling system
	Ductwork, including insulation, expansion joints and supports
	Precipitator upgrade - minimal allowance
	Boiler Pressure Parts, X-ray, etc., both boilers
	Ash handling system allowance
	Piping, Instrumentation, Electrical
	Steel and Foundations
No. 8 Blr	Hot Side OFA/SIS includes lime handling system
	Ductwork, including insulation, expansion joints and supports
	Precipitator upgrade - major allowance
	Ash handling system
	Piping, Instrumentation, Electrical
	Steel and Foundations

Including contingencies and design engineering, the cost range for the OFA/SIS system is estimated to be $19,400,000.

5.4.2 Operating and Maintenance Costs

The following table is an estimate of the operating and maintenance costs, including other environmental costs:

Table 4-6
Overfire Air and Sorbent Injection System Annual Operating & Maintenance Costs

Annual Cost	Cost in Thousands	
	No. 7 Coal Boiler	No. 8 Coal Boiler
Chemical – caustic soda @ $200/ton	$973	$1258
Power @ $0.05/kwh	$97	$129
Landfill costs @$20/ton	$1,084	$1,502
Maintenance	$175	$250
Total	**$5,468**	

6.0 Energy and Non-Air Environmental Impact Evaluation

There were additional energy needs and landfill (i.e., non-air environmental) needs from the three selected control strategies. The following will detail the impact.

6.1 Wet FGD

6.1.1 No. 7 Coal Boiler

Although the ID fan was judged to be adequate, there would be an additional 120 horsepower usage from the increased pressure drop requirements of the wet FGD. Also, there is a 30-horsepower recycle pump on the FGD fan which recycles the FGD slurry.

The captured SO_2 combines with the caustic soda to form a slurry which leaves the system via the FGD blowdown. The slurry will be captured in the existing plant wastewater system, dewatered, and landfilled. Potential issues in wastewater treatment would need to be further evaluated. The estimated quantity is 16,000 tons per year or about 2 tons per hour additional.

6.1.2 No. 8 Coal Boiler

The ID fan motor will be replaced with a larger motor that utilizes an additional 160 horsepower usage from the increased pressure drop requirements of the wet FGD. Also, there is a 40-horsepower recycle pump on the FGD fan which recycles the FGD slurry.

The captured SO_2 combines with the caustic soda to form a slurry which will leave the system via the FGD blowdown. The slurry will be captured in the existing plant wastewater system, dewatered, and landfilled. Potential issues in wastewater treatment would need to be further evaluated. The estimated quantity is 25,000 tons per year or about 3 tons per hour additional.

6.2 Semi-Dry FGD

6.2.1 No. 7 Coal Boiler

Although the ID fan was judged to be adequate, there would be an additional 60 horsepower usage from the increased pressure drop requirements of the wet FGD. Also, there is a 300-horsepower air compressor for dispersing the slurry.

The captured SO_2 combines with the quick lime to form a particle. The particle will be captured in the existing precipitator and landfilled. The estimated quantity is 28,000 tons per year or about 3 tons per hour additional.

6.2.2 No. 8 Coal Boiler

The ID fan motor will be replaced with a larger motor that consumes an additional 160-horsepower of usage from the increased pressure drop requirements of the wet FGD. Also, there is a 300-horsepower air compressor for dispersing the slurry.

The captured SO_2 combines with the quick lime to form a particle. The particle will be captured in the existing precipitator and landfilled. The estimated quantity is 45,000 tons per year or about 6 tons per hour.

6.3 Overfire Air and Sorbent Injection System

6.3.1 No. 7 Coal Boiler

A 300-horsepower overfire air fan will be added to the system.

The captured SO_2 combines with the limestone in the furnace forming a particle. The particle will be captured in the existing precipitator and landfilled. The estimated quantity is 54,000 tons per year or about 6 tons per hour additional.

6.3.2 No. 8 Coal Boiler

A 400-horsepower overfire air fan will be added to the system.

The captured SO_2 combines with the limestone in the furnace forming a particle. The particle will be captured in the existing precipitator and landfilled. The estimated quantity is 75,000 tons per year or about 9 tons per hour.

7.0 Financial Analysis

7.1 Approach

There are uncertainties both with the order-of-magnitude capital cost estimate and the projected chemical, energy, solid waste, and maintenance costs. To account for these uncertainties, the capital and operating costs are allowed to vary within prescribed ranges (typically ±10%). The financial analysis is repeated such that 1000 capital cost estimates and 1000 – 10-year amortization periods are developed. The following summarizes the results of this analysis (10-year amortization period at a 15% discount rate):

The result of the analysis is a net present value (NPV), which converts the annual costs over the 10-year period to today dollars utilizing a discount rate of 15%.

The remainder of the section will summarize the NPV for each of the investigated control strategies and then summarize the results in the form of NPV $/ton of SO_2 removed.

7.2 Wet FGD

Description	Wet FGD			
	Accuracy	**Type**	**Average**	**Range or Rel Var**
Annual Savings	**Savings entered as positive numbers**			
Raw Materials/Chemicals	**Inflation Rate**			
Caustic Soda	5%	Range	($8,280,000)	10.00%
Hydrated Lime	5%	Range	$5	10.00%
Limestone	5%	Range	$5	10.00%
Utilities				
Electricity	3%	Range	($112,000)	10.00%
Steam	3%	Range	$0	10.00%
Water	3%	Range	$0	5.00%
Solid Waste	5%	Range	($824,000)	10.00%
Operational Impact				
Personnel	3%	Range	$0	10.00%
Maintenance – Routine/Prev.	5%	Range	($200,000)	10.00%
Maintenance – Annual	5%	Range	($300,000)	10.00%
Results	**Average**	**Min**	**Max**	
First Year Pre-Tax Savings	($10,202,737)	($11,142,677)	($9,218,307)	
NPV	($56,286,147)	($62,755,249)	($49,633,502)	
Return on Investment	N/A			

7.3 Semi-Dry FGD Before Existing Precipitators

Description	Semi-Dry FGD Before Existing Precipitators			
	Accuracy	Type	Average	Range or Rel Var
Annual Savings	Savings entered as positive numbers			
Raw Materials/Chemicals				
Caustic Soda		Range	$0	10.00%
Hydrated Lime		Range	($4,724,000)	10.00%
Limestone		Range	$5	10.00%
Utilities				
Electricity		Range	($271,000)	10.00%
Steam		Range	$0	10.00%
Water		Range	$0	5.00%
Solid Waste		Range	($1,461,000)	10.00%
Operational Impact				
Personnel		Range	$0	10.00%
Maintenance – Routine/Prev.		Range	($200,000)	10.00%
Maintenance – Annual		Range	($300,000)	10.00%
Results	**Average**	**Min**	**Max**	
First Year Pre-Tax Savings	($7,307,489)	($7,949,414)	($6,635,633)	
NPV	($52,100,722)	($60,057,256)	($44,118,782)	
Return on Investment	N/A			

7.4 Overfire Air and Sorbent Injection System

Description	OFA and SIS			
	Accuracy	**Type**	**Average**	**Range or Rel Var**
Annual Savings	**Savings entered as positive numbers**			
Raw Materials/Chemicals				
Caustic Soda		Range	$0	10.00%
Hydrated Lime		Range	$0	10.00%
Limestone		Range	($2,231,000)	10.00%
Utilities				
Electricity		Range	($226,000)	10.00%
Steam		Range	$0	10.00%
Water		Range	$0	5.00%
Solid Waste		Range	($2,586,000)	10.00%
Operational Impact				
Personnel		Range	$0	10.00%
Maintenance – Routine/Prev.		Range	($175,000)	10.00%
Maintenance – Annual		Range	($250,000)	10.00%
Results	**Average**	**Min**	**Max**	
First Year Pre-Tax Savings	($5,726,322)	($6,245,488)	($5,199,439)	
NPV	($35,514,726)	($40,032,634)	($30,892,537)	
Return on Investment	N/A			

7.5 Net Present Value Summary

The following table summarizes the net present value $/ton of SO_2 removed:

De-Sulfurization Technology	SO_2 Removed		NPV $/ton SO_2 removed		
	%	**TPY**	**Average**	**Min**	**Max**
Wet	90%	20,515	$2744	$2420	$3060
Semi-Dry Before Existing Precipitators	90%	20,515	$2540	$2150	$2927
OFA/SIS	60%	13,677	$2597	$2259	$2927

8.0 Summary of BART Engineering Analysis

The BART regulation requires certain sources of visibility-impairing pollutants to install controls equivalent to the Best Available Retrofit Technology for that source. BART applies to sources of visibility impairing pollutants that were constructed between 1962 and 1977 and that are in one of 26 major sources categories. The visibility-impairing pollutants are SO_2, NO_x, and particulate.

The No. 7 Coal Boiler and No. 8 Coal Boiler at the Chillicothe mill are subject to BART requirements. The initial modeling by Ohio EPA for No. 7 and No. 8 Coal Boilers indicated that a minimum of 58% sulfur dioxide removal from the baseline will be required, while the currently installed floor technology NO_x control meets BART requirements.

A top-down engineering analysis was performed and involved the following steps:

- Identify available control technologies for each pollutant/source combination.
- Evaluate technical feasibility of control options based on site or source specific factors.
- Evaluate the cost impacts of each technically feasible control option.
- Determination of the energy and non-air quality environmental impacts of each technically feasible control option.

The following SO_2 control technologies were evaluated in this engineering analysis:

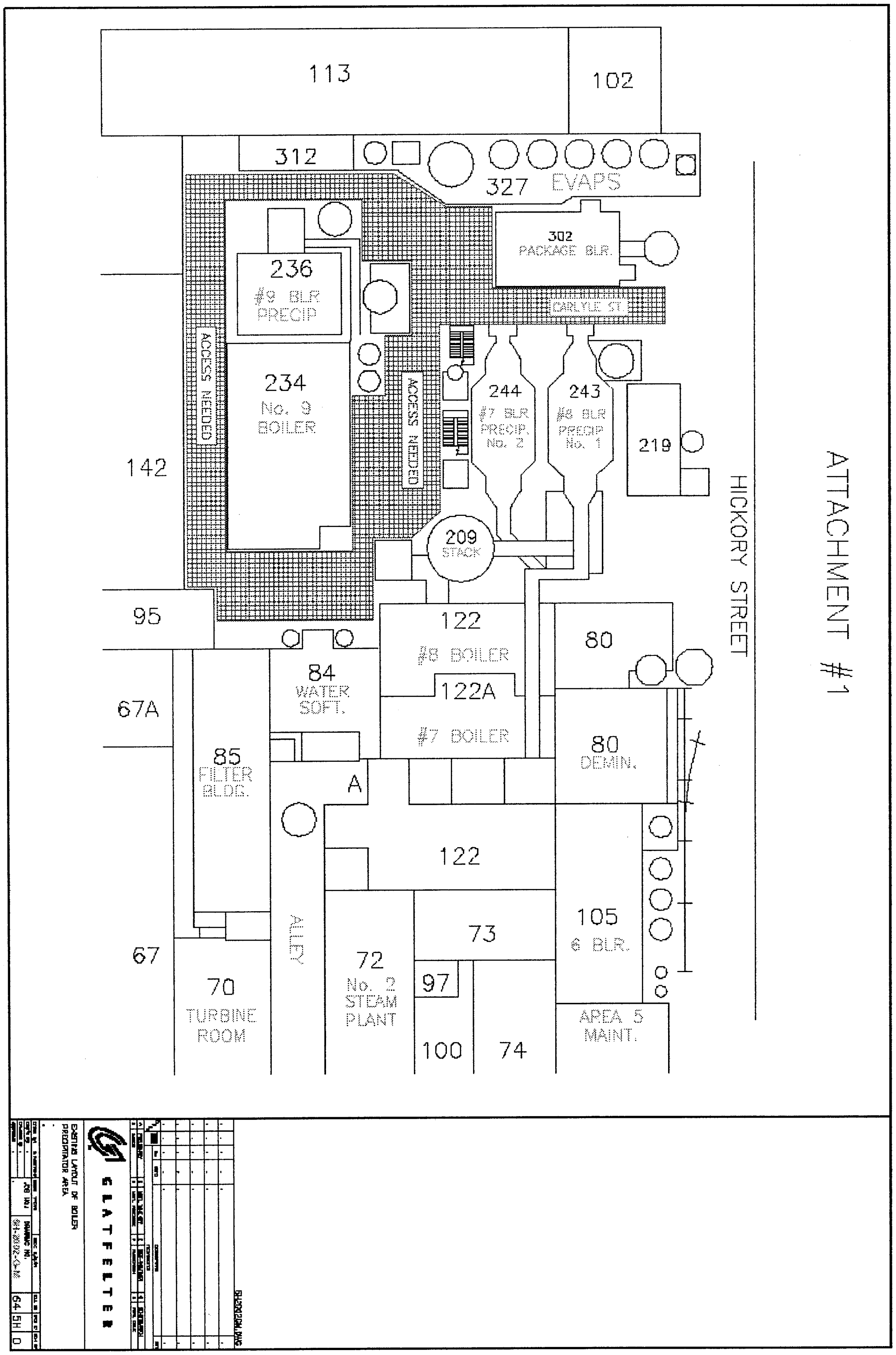
- Wet Electrostatic Precipitator
- Wet Flue Gas De-sulfurization (FGD)
- Semi-dry Flue Gas De-sulfurization ahead of the existing precipitators
- Semi-dry Flue Gas De-sulfurization with baghouse after the existing precipitators
- Overfire Air (OFA) and Sorbent Injection System (SIS)

Several fuel switching or re-design options, such as changing to low sulfur coal, were also considered; however, they are not required to be included in the BART Engineering Analysis, nor deemed as to warrant additional consideration at this time.

The technical feasibility, cost impacts, advantages and disadvantages were evaluated for each control option. The list of potential control options was narrowed down to the following three technologies: Wet FGD, Semi-dry FGD ahead of the existing precipitators, and an OFA/SIS system. Additional air quality modeling for visibility impacts of these technologies is to be completed by Ohio EPA.

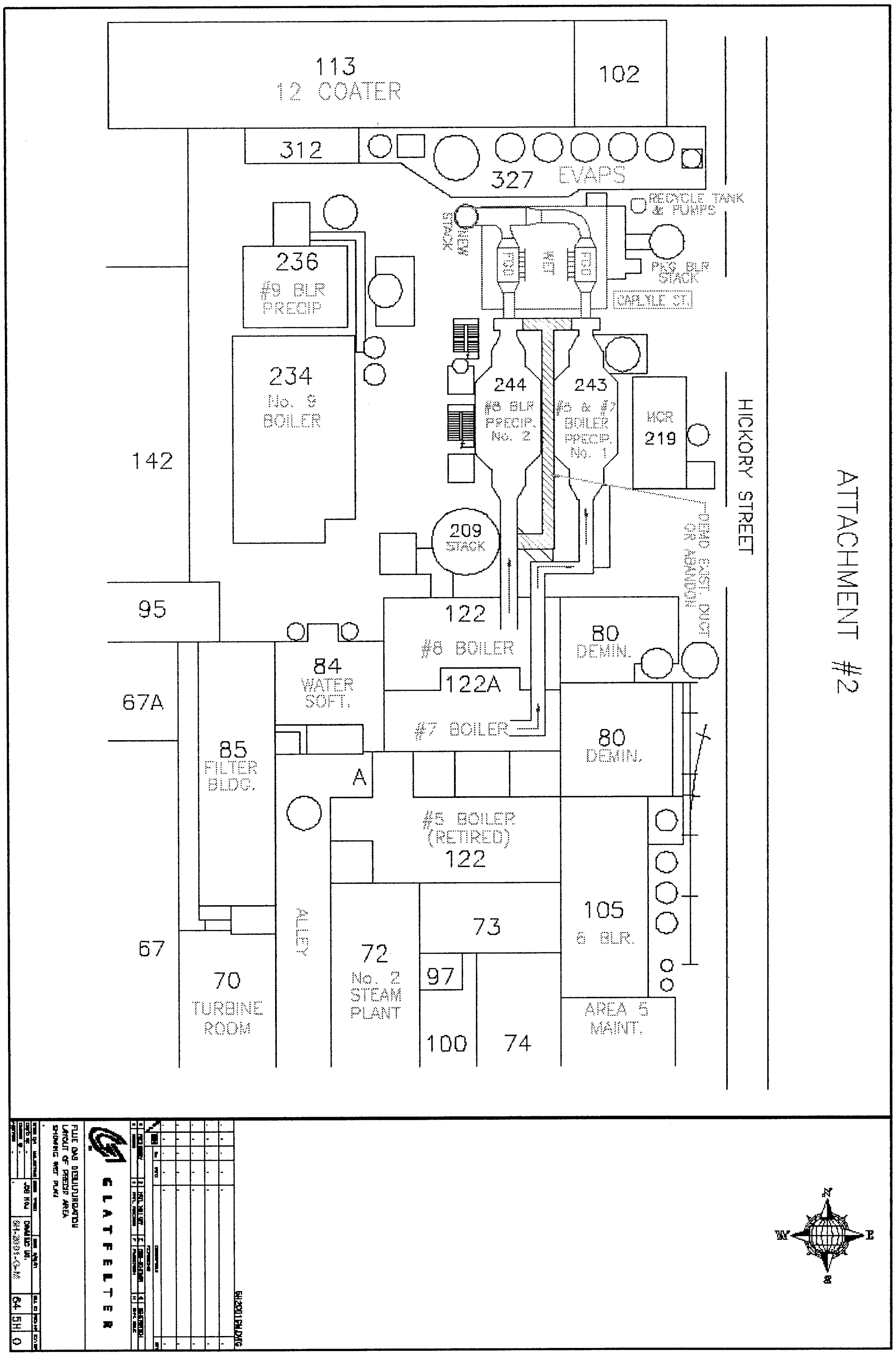
ATTACHMENT 1 –

Existing Layout of Boiler and Precipitator Area


ATTACHMENT #1
HICKORY STREET
113
102
312
327 EVAPS
302
PACKAGE BLR.
CARLYLE ST
236
#9 BLR
PRECIP
234
No. 9
BOILER
ACCESS NEEDED
ACCESS NEEDED
244
#7 BLR
PRECIP.
No. 2
243
#6 BLR
PRECIP
No. 1
219
142
209
STACK
95
122
#8 BOILER
122A
#7 BOILER
80
84
WATER
SOFT.
67A
80
DEMIN.
85
FILTER
BLDG.
A
122
ALLEY
105
6 BLR.
73
67
70
TURBINE
ROOM
72
No. 2
STEAM
PLANT
97
100
74
AREA 5
MAINT.
GLATFELTER

ATTACHMENT 2 –

Potential Wet Flue Gas De-sulfurization Layout of Precipitator Area

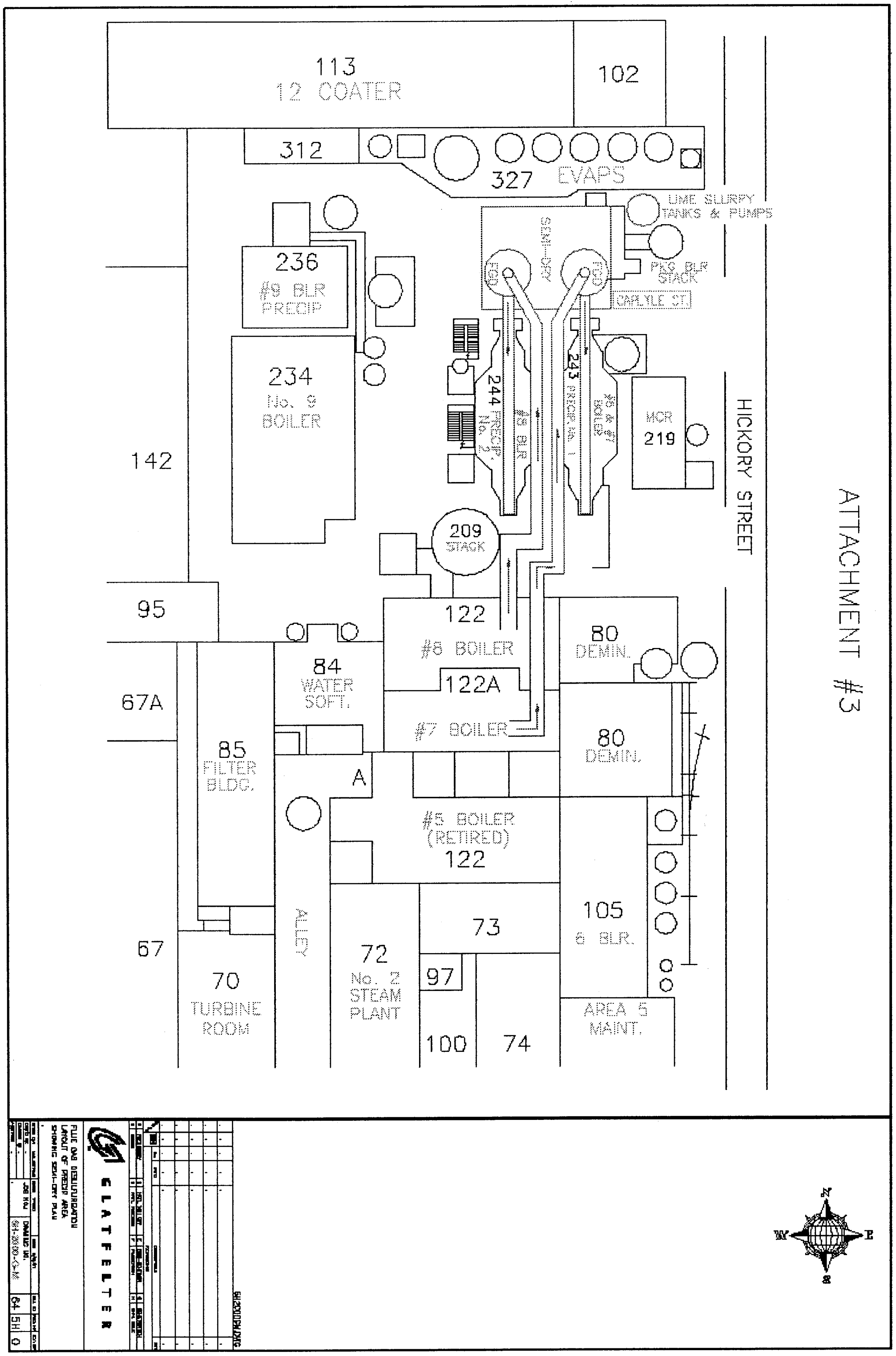


ATTACHMENT #2
113
12 COATER
102
312
327 EVAPS
RECYCLE TANK & PUMPS
NEW STACK
FGD
WET
FGD
PKG BLR STACK
CARLYLE ST.
236
#9 BLR PRECIP
234
No. 9 BOILER
244
#8 BLR PRECIP. No. 2
243
#5 & #7 BOILER PRECIP. No. 1
MCR 219
HICKORY STREET
DEMO EXIST. DUCT OR ABANDON
142
209 STACK
95
122
#8 BOILER
122A
#7 BOILER
80 DEMIN.
80 DEMIN.
84 WATER SOFT.
67A
85 FILTER BLDG.
A
#5 BOILER (RETIRED)
122
ALLEY
105
6 BLR.
73
67
70 TURBINE ROOM
72 No. 2 STEAM PLANT
97
100
74
AREA 5 MAINT.
GLATFELTER
N
W
E
S

ATTACHMENT 3 –

Potential Semi-Dry Flue Gas De-sulfurization Layout of Precipitator Area (Ahead of the Existing Precipitators)

ATTACHMENT #3



ATTACHMENT 4 –
Visibility Modeling Analysis
(Provided by Ohio EPA)

The Ohio EPA Division of Air Pollution Control (OEPA DAPC) modeled the visibility impact of Glatfelter's No. 7 and No. 8 coal boilers as a part of a larger study involving either screening analysis or detailed modeling of all BART candidates in Ohio. This study was performed by DAPC with substantial technical assistance from the Lake Michigan Air Directors Consortium (LADCO). The purpose of the modeling is to identify the facilities having an impact on downwind Class I areas (e.g., national parks and wilderness areas) exceeding a certain threshold. The definition of the threshold is that no facility may contribute more than seven days of visibility impairment exceeding 0.5 deciviews in any single Class I area in any of the modeled meteorological years 2002, 2003, or 2004. SO2, NOx, primary fine particulate matter, HNO3, and sulfate are the chemical species considered to be significant in terms of visibility. The downwind dispersal of these pollutants is computed by the Calpuff computer model, and the modeled concentrations, combined with assumed background concentrations, are converted to deciviews with the aid of post-processor software. The document "Single Source Modeling to Support Regional Haze BART / Modeling Protocol" (March 21, 2006) by the Lake Michigan Air Directors Consortium supplied details of the procedure, which were incorporated into data files and run scripts supplied to DAPC by LADCO. Discussion of the procedures followed by DAPC is also contained in a report to the U.S. EPA Region 5 currently in the process of preparation.

The following conditions represent the pre-control baseline:

SO_2 and NOx

Glatfelter provided daily emission rates for each boiler, for years 2003, 2004, and 2005. A boiler modification occurred in early 2003, so only the last 274 days of that year were considered to be representative of current conditions. Initially, DAPC understood that the 98^{th} percentile of emission rate, for a single year, was appropriate for modeling, and the daily rates were analyzed to determine the 98^{th} percentile of combined emission from the two boilers, for year 2005. This resulted in the following numbers:

NOx:	57.89 g/s
SO_2:	1060.1 g/s

Subsequently, DAPC received indications that the single highest day of combined emission over a three year period may be called for. When 2005, 2004, and 274 days of 2003 data were reviewed, the following numbers were extracted:

NOx	59.316 g/s
SO_2	1308.87 g/s

Based on design values of 422 MMBtu/hr and 505 MMBtu/hr for boilers 7 and 8 respectively, this would correspond to coal quality of 11.2 lb SO_2/MMBtu. This is greater than their SIP limit of 9.9 lb SO_2/MMBtu, but since the 9.9 limit is evaluated over a longer averaging period than 24 hours, the numbers do not demonstrate a violation.

Sulfate, HNO3, and primary fine particulate

Sulfate and HNO3 have not been inventoried, are not believed to be emitted in significant quantity, and were not modeled. Both pm2.5 and pm10 have been inventoried by DAPC for year 2002, as follows:

pm2.5: 0.28 TPY, = 0.008105 g/s averaged over actual operating hours.

pm10: 29.7 TPY, = 0.859 g/s averaged over actual operating hours

The protocol calls for pm2.5 to be modeled, but because that number appears questionable, the value of 0.859 g/s for pm10 was modeled instead. In either case, the contribution of primary particulate to modeled visibility impact is extremely minor.

Stack parameters

Location:	lat. 39/19/29.864; long. 82/58/29.025;
	Lambert (1194.855 km, 17.745 km)
Stack base elevation:	615 feet
Height:	475 feet
Diameter:	14 feet
Temperature:	305.3 deg. F
Velocity	54.14 ft/sec

The two boilers vent to a combined stack; hence only one stack was modeled.

Modeling of these baseline conditions showed the following numbers of days of visibility deterioration exceeding 0.5 deciviews (areas of highest impact, only, shown) (using single-highest-day emission rates):

Class I area	days above visibility-degradation threshold (uncontrolled, at 1308.87 g/s)		
	(2004)	(2003)	(2002)
Dolly Sods	31	23	23
Mammoth Cave	21	14	12
Shenandoah	38	37	20
Great Smoky	10	8	5

These numbers greatly exceed the "7 days in any year" criterion.

Next, a series of model runs was performed to determine how much reduction of SO_2 emissions is needed to bring the impact below the threshold. All stack parameters and emission rates except for SO_2 were left unchanged, even though the Company has indicated that some reduction in NOx can be expected under their proposed controls. An SO_2 rate of 553 g/s, corresponding to 57.7 percent control, was found to bring the impact below the threshold of significance, as follows:

Class I area	days above visibility-degradation threshold (controlled at 553 g/s or 57.7% reduction)		
	(2004)	(2003)	(2002)
Dolly Sods	6	3	7
Mammoth Cave	6	6	5
Shenandoah	3	6	7
Great Smoky	1	4	2

For the two levels of control being considered, 60 percent and 90 percent, the modeled impacts are as follows:

Class I area	days above visibility-degradation threshold (controlled at 523.55 g/s or 60% reduction)		
	(2004)	(2003)	(2002)
Dolly Sods	4	3	6
Mammoth Cave	5	6	4
Shenandoah	2	3	7
Great Smoky	1	4	2

Class I area	days above visibility-degradation threshold (controlled at 130.887 g/s or 90% reduction)		
	(2004)	(2003)	(2002)
Dolly Sods	0	0	0
Mammoth Cave	0	1	0
Shenandoah	0	0	0
Great Smoky	0	0	0

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Appendix H

BART-Eligible Electric Utility Generating Units in Ohio

(preliminary list)

Facility	boiler	county	heat input
J. M. Stuart	1	Adams	32.8
J. M. Stuart	2	Adams	39.8
J. M. Stuart	3	Adams	36.9
J. M. Stuart	4	Adams	31.6
Ashtabula	8	Ashtabula	1.8
Ashtabula	9	Ashtabula	1.6
Ashtabula	10	Ashtabula	2.2
Ashtabula	11	Ashtabula	2.3
City of St. Mary's	6	Auglaize	0.6
City of Hamilton	8	Butler	1.3
City of Hamilton	9	Butler	2.7
W. C. Beckjord	5	Clermont	16.0
W. C. Beckjord	6	Clermont	27.4
Conesville	3	Coshocton	5.9
Conesville	4	Coshocton	27.4
Conesville	5	Coshocton	23.9
Gen. J. M. Gavin	1	Gallia	85.4
Gen. J. M. Gavin	2	Gallia	100.1
Miami Fort	7	Hamilton	38.0
Cardinal	1	Jefferson	29.0
Cardinal	2	Jefferson	26.4
Cardinal	3	Jefferson	38.5
W. H. Sammis	4	Jefferson	13.0
W. H. Sammis	5	Jefferson	17.2
W. H. Sammis	6	Jefferson	40.5
W. H. Sammis	7	Jefferson	39.2
Eastlake	5	Lake	31.9
City of Painesville	4	Lake	0.9
City of Painesville	5	Lake	1.2
Avon Lake	12	Lorain	34.6
Bay Shore	3	Lucas	7.6
Eastlake	4	Lucas	10.5
Muskingum River	5	Morgan	37.0
City of Shelby	1	Richland	0.7
City of Shelby	2	Richland	0.6
City of Dover	4	Tuscarawas	1.2
City of Orrville	13	Wayne	2.2

OEPA/DAPC, Dec. 2008