BART Determination – Amended July 2011
Georgia Pacific Broadway Mill, Green Bay Wisconsin
Facility ID 405032870

Prepared by

Wisconsin Department of Natural Resources
Bureau of Air Management /RPMS Section

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Introduction

The Georgia Pacific Broadway Mill in Green Bay, Wisconsin operates two coal-fired power boilers subject to Best Available Retrofit Technology (BART) under the Clean Air Act (CAA). In June of 2010, the Department provided for external review a draft finding of BART requirements applicable to the affected Georgia Pacific boilers (Attachment 1). This document amends the draft BART finding for Georgia Pacific and provides response to public comment. The BART requirements for Georgia Pacific will comprise a component of Wisconsin's State Implementation Plan addressing regional haze and will contribute to reasonable progress goals (RPG) by 2015 and after. Specific requirements and contribution by non-BART industrial boilers, at Georgia Pacific and sector-wide, to RPG will be evaluated as part of the next RPG evaluation in 2018 as described in the Haze SIP document.

Section I. Summary of Amended BART Determination

The Georgia Pacific BART requirements address emissions of particulate matter (PM), sulfur dioxide (SO_2), and nitrogen oxides (NOx) from two power boilers B26 and B27. The two affected boilers exhaust through common Stack S10 along with the coal-fired boilers B24, B25 and B28. The BART requirement for each pollutant is summarized as follows:

Particulate Matter (PM)
The draft finding proposed PM requirements based on the existing control equipment and permit limitations and required additional minimizing of PM emissions through the use of this equipment. The BART determination for PM is amended to require only the existing PM controls and permit limitations.

Sulfur Dioxide (SO_2)
The draft finding proposed SO_2 requirements based on application of dry scrubbing circulating fluidized bed (CFB) absorber technology achieving 95% control of SO_2 emissions. The department developed costs and control levels based on a commercially available CFB unit called Turbosorp.

The BART determination for SO_2 is amended to reflect that CFB technology is capable of meeting a 93% long-term compliance requirement. This determination further establishes "Base SO_2 emissions" reflecting a presumptive fuel with specified sulfur contents. The BART compliance requirement is established by applying 93% control to the "Base SO_2 emissions"

Nitrogen Oxide (NOx)
The draft finding proposed NOx requirements based on the application of combustion modifications followed by a type of tail-end selective catalytic reduction technology with regenerative heat recovery (regenerative SCR or referred to here as RSCR). These controls in combination were estimated to achieve control efficiencies of 84% and 92% for boilers B26 and B27, respectively.

The BART determination for NOx is amended for both boilers B26 and B27. The requirement for boiler B26, a stoker boiler, now reflects combustion modifications followed by selective non-catalytic reduction technology (SNCR) to achieve an overall 68% long-term compliance reduction. For B27, a cyclone boiler, the requirement reflects overfire air combustion modifications followed by one of several different available control options: RSCR, rich-reagent injection (RRI), or SNCR. These equipment configurations are determined to yield an 84% long-term compliance control requirement.

Summary of BART Control Levels and Visibility Improvement

The baseline year average emissions (2002 – 2004) emitted from the Georgia Pacific Stack S10 boiler system is modeled to determine baseline visibility impact in deciviews (dv). The results, in Table 1, show the Seney Class I area receiving a maximum daily impact of 5.38 deciview. The average of each baseline year's maximum daily impact for Seney is 4.14 deciview. Adding the maximum impact for each northern Class I areas results in a total impact of 8.12 deciview. This shows Seney recieves approximately one half of the impact from Georgia Pacific to the northern Class I areas. To be noted is that the maximum impact for each area is not expected to occur simultaneously. Rather the total value is a metric for measuring total relative impact.

Table 1. Visibility Impact (dv) for Uncontrolled Base Year SO_2 and NOx Emissions: 2002, 2003, 2004

Seney		Northern Class I Areas	
Maximum	Average	Maximum	Average
5.38	4.14	9.67	8.12

The improvements to the average visibility impact (4.14 for Seney, 8.12 for northern areas) related to BART requirements are also modeled. The results show, in Table 2, a 2.02 deciview improvement for Seney and 4.19 deciview improvement in total for the northern Class I areas.

Table 2. Boiler B26 and B27 BART Control Levels and Resulting Visibility Improvement.

Emission Unit	BART Technology and Control Efficiency			Visibility Improvement (dv)			
				Seney		Northern Areas	
	SO_2	NO_x	PM_{10}	SO_2	NO_x	SO_2	NO_x
B26	Dry FGD – 93%	OFA/FGR/SNCR – 68%	Existing Baghouse - > 99%	1.23	0.52	2.79	0.87
B27	Dry FGD – 93%	OFA + RSCR – 84%	Existing Baghouse - > 99%				
Total BART				2.02		4.19	

1) Visibility improvement values are the average of the maximum daily impact identified for each BART base year 2002 to 2004 (Table 5.2)
2) Pollutants when reduced together yield a greater visibility improvement than visibility improvement modeled for each pollutant individually.
Northern Areas = Isle Royale National Park, Seney Wilderness Area, Boundary Waters Canoe Wilderness Area and Voyageurs National Park.

BART Compliance Requirements

The draft BART determination proposed emission limitations for emissions levels from the common Stack S10 – emissions for boilers B24 through B28. These proposed emission limitations were calculated using fuel consumption and emissions for each boiler over the baseline years of 2002 to 2004 and applying the BART control efficiencies to boilers B26 and B27.

In amending the compliance requirements the fuel consumption during the baseline years remains the primary basis for representing boiler utilization and determining compliance requirements. The SO_2 emission requirements are calculated using base year SO_2 emissions that are first adjusted to reflect a surrogate fuel for each boiler. For NOx, base year emissions reflect the actual historic emission rates as NOx emissions are directly related to boiler combustion parameters which typically do not change over time.

Several compliance approaches or alternatives are provided in the permit for meeting the BART requirements. These requirements are structured as either emission rate limitations or mass emission caps as 30 day or 12 month rolling averages (Table 2). Both 30 day and 12 month limits apply in tandem to address daily visibility improvement accounting for operating variability (30 day) while ensuring long-term BART reductions (12 month). The complete list of compliance methods are:

- Complying with a 30 day rolling emission limit or a 30 day mass cap and annual mass cap individually for each boiler B26 and B27.
- Complying with a 30 day rolling emission limit (original format) or a 30 day mass cap and annual mass cap for the common stack.
- Complying with a 30 day mass cap and annual mass cap for the common stack where additional SO_2 reductions are traded to offset avoided NOx reductions. Under the trading approach two tons of SO_2 must be reduced to offset each required ton of NOx reduction.

Georgia Pacific can comply with either the emission rate limitation or the set of mass cap limitations applicable to the individual BART boilers or to the common S10 stack. These emission limitations are presented in Table 3.

Table 3. Summary of BART Compliance Requirements

Emission Unit(s)	Emission Rate Requirements		Mass Cap Requirements	
	12 Month Rolling Emission Rate Limitation (lbs/mmBtu)	30 Day Rolling Emission Rate Limitation (lbs/mmBtu)	Tons Emitted in any 12 Month Period	Tons Emitted in any 30 Day Period
SO_2				
B26		0.27	254	33
B27		0.23	502	47
Stack S10	1.01	1.53	5,800	761
NOx				
B26		0.22	207	27
B27		0.20	437	41
Stack S10	0.21	0.28	1,200	141

Section II. Determination of BART Control Levels

The determination of BART controls is a top-down process similar to a determination of Best Available Control Technology (BACT). An important distinction however is that BACT primarily considers cost of control in dollars per ton of pollutant reduced ($/ton). The determination of BART control levels, as outlined under 40 CFR Part 51, Appendix Y, *Guidelines for BART Determinations Under the Regional Haze Rule*, is primarily based on the degree of visibility improvement considered in conjunction with the following five factors:

1. Available technology
2. Cost of compliance
3. Energy and non-air environmental impacts
4. Existing pollution control equipment
5. Remaining useful life

The primary metrics for comparing cost of technologies are total cost, cost per ton of pollutant removed ($/ton) and cost of visibility improvement in deciviews ($/dv). Consideration is also given to the incremental (marginal) visibility improvement and cost.

Similar to BACT, the actual BART can be implemented by establishing a requirement to install and operate the control equipment at specific control efficiencies or by establishing a continuous emission limitation. The Georgia Pacific BART requirements are implemented as emission limitations which are incorporated into the facility's Title V operating permit (Appendix A).

1. Particulate Matter (PM) BART

Georgia Pacific currently employs a baghouse to the common Stack S10 for particulate matter (PM) control. Emissions testing shows 99% control for coarse particulate matter ($PM_{10)}$. The For evaluating whether additional PM control is necessary under BART the Department modeled the maximum actual baseline PM_{10} emissions. A zero-out run of PM emissions (100% control) showed a maximum visibility improvement of 0.04 dv for Seney. The number of days with a maximum visibility impairment of 0.1 dv or greater were reduced by only 2 days (122 days to 120 days).

Due to the small improvement in visibility, the Department determined the draft PM BART at Georgia Pacific to be the existing PM controls and permit limitations. However, the Department also originally proposed that the facility implement a plan for continuously minimizing PM emissions through operational procedures. After further review, PM controls are operated at a very high level achieving 0.025 lbs/mmBtu emission rates.[1] Furthermore, Georgia Pacific is subject to malfunction and abatement plans, under ch. NR 439, Wis. Adm. Code, for operating control equipment in a manner consistent with testing parameters. Therefore, the Department concludes an additional plan for minimizing PM emissions will lead to negligible or no additional reduction in PM or improvement to visibility. Therefore the Department deems the

[1] August 26, 2008 particulate test on Stack 10

existing PM controls and permit limitations constitute BART PM requirements for boilers B26 and B27.

2. Sulfur Dioxide (SO_2) BART

The Department compared wet flue gas desulfurization (FGD) and dry circulating fluidized bed FGD in preparing the draft BART determination. This evaluation showed that both technologies achieve comparable control of SO_2, but the capital cost of wet FGD is almost twice that of the dry CFB FGD. The Department concluded that the incremental costs do not substantiate the application of wet FGD and that BART should be based on the application of dry CFB FGD technologies designed for high control efficiencies (90 – 95%). The latter portion of this statement means that any installed scrubber system should be designed for the highest control levels. The operation of the scrubber can be scaled to meet the effective emission limitations as necessary.

The Department maintains, under this amended BART determination, that dry CFB FGD represents SO_2 BART for boilers B26 and B27. After further review, the Department has determined that this technology can achieve 95% control efficiency, but that long term operation and compliance is represented by 93% control efficiency. The basis for this conclusion is described here. This determination also updates the costs and visibility improvements originally estimated for the draft BART determination.

- *Dry CFB FGD Control Efficiency*

Under draft BART determination a 95% SO_2 control efficiency was proposed for the combined emissions of boilers B26 and B27. This control efficiency was based on circulating fluidized bed dry scrubbing as represented by an evaluation of Turbosorp control equipment and costs. Georgia Pacific provided comment that a 95% SO_2 control efficiency does not provide compliance margin in accounting for operating variability. In response, the Department conducted addition review of actual operations and engineering assessments for both Turbosorb and other CFB type of installations. A summary of this review is shown in Table 2.1 below.

The Turbosorp system is operating on Unit 4 of the AES Greenidge facility in North Carolina. This system is similar to the Georgia Pacific case where the Turbosorp unit was installed to an existing boiler unit - both similar in size and the flue gas characteristics to boilers B26 and B27 (~100 MWe and firing mid- to high-sulfur coal).[2] Extensive performance testing at the facility provides insight into how changes in different factors, such as inlet SO_2 concentration and boiler load changes, affect the overall control efficiency. The testing shows SO_2 control efficiency decreased ~ 96.8% to ~ 95.3%, when the unit load is decreased from the 100 MWe down to the 70 MWe (gross) range, a 30% change. This is an approximate decrease in control efficiency of 1.5 %. From historic information, the Georgia Pacific stack S10 boiler system typically ranges in load between 600,000 and 800,000 lb/hr, a 25% load swing. Since actual demonstrated change in control efficiency is 1.5% for 30% load swing, similar to a 25% load swing, a 2% change is applied here to allow for a compliance margin.

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[2] Greenidge Multi-pollutant Control Project. U.S. Department of Energy Cooperative Agreement DE-FC26-06NT41426..

The Gainesville Regional Utilities also use a Turbosorp unit at the Deerhaven Station in Florida.[3] The flue gas SO_2 concentration is 2.2 lb/mmBtu with a removal efficiency approaching 95%. This Turbosorp unit treats flue gas with SO2 at 3.8 lb/mmBtu to achieve removals up to 97.2%. The Westmoreland Roanoke Valley power plant in North Carolina also uses CFB technology for SO_2 removal. The Roanoke boiler unit is limited to 1.6% sulfur, and has a SO_2 removal requirement of 93%.

In 2006 the Washington Group International evaluated CFB technology for SO_2 removal at each of two 200 MWe units at We Energies' Oak Creek facility.[4] The design coal had a sulfur content of 0.5%. In the evaluation, We Energies settled on 95% SO_2 removal because each unit was not "large" (i.e. > 250 MWe). The evaluation also indicated that 96-98% SO_2 removal was possible with the addition of extra water, but that this removal had not been demonstrated at the time of the evaluation.

In 2008 Alliant Energy evaluated CFB for SO_2 removal at each of two 100-MWe units at the Nelson Dewey facility in Wisconsin.[5] The design coal was 85% powder river basin coal (PRB) and 15% petroleum coke, with a resulting emission rate of 2.4 lb/mmBtu SO_2. The evaluation indicated a 95% long-term SO_2 reduction.

Across these multiple cases the SO_2 control efficiency for CFB type of control equipment ranges from 93 to 98% removal. However the operating data and engineering assessments for units treating SO_2 concentrations similar to the Georgia Pacific application show an expected control efficiency up to 95% removal. Assuming a 2% decrease in removal efficiency due to operating variability, as shown by the Greenidge testing, represents a compliance efficiency of 93% removal. The Department finds that 93% is sufficient in addressing variability and appropriate in determining long term performance requirements for a CFB unit applied to the Georgia Pacific BART boilers.

[3] Ake, Terrence. "Commissioning a Large Turbosorp Circulating Dry Scrubber." Presentation at Power Plant Air Pollutant Control "MEGA" Symposium. September 2010. Baltimore, MD.
[4] Wisconsin Public Service Commission. Docket 6630-CE-299. February 15, 2011.
[5] Wisconsin Public Service Commission. Docket 5-CE-138. February 15, 2011.

Table 2.1 System Performance for Turbosorp and Other Dry FGD Technologies, Applied or Planned.

		From Babcock Power			From NEEDs Database				From NPS BART Compilation (updated 08/2010)					
	GP	Greenidge - NC *	Deerhaven - FL (Case 1) *	Deerhaven - FL (Case 2)*	Altavista - VA	Southampton - VA	Roanoke - NC	Edgecombe - NC	Eastman - TN (non-EGU)	Stanton - ND	Stanton - ND	Pacificorps - WY	CSU - CO	CSU - CO
Control Technology	CFB (Turbosorp)	CFB (Turbosorp)	CFB (Turbosorp)	CFB (Turbosorp)	SDA	SDA	CFB	SDA	SDA	CFB	SDA	SDA	SDA	SDA
Installation Date	---	2006	2010	2010	1992	1995	1995	1990	---	---	---	---	---	---
Heat input (mmbtu/hr) and/or MW output	965 (75 MW)	107 MWe	238 MWg	238 MWg	31.5 MW x2	63 MW	44 MW	28.9 MW	655 x 5	1,800	1,800	2,500	1,336	850
Pre-control (tpy)	10,889	14,877	N/A	N/A	N/A	N/A	N/A	N/A	14,309	9,376	9,376	13,316	4349	2853
Pre-control (#/mmBtu)	3.48	3.62	3.8	2.2	Fuel limited to 1.5% S	Bituminous	Fuel limited to 1.6% S	Bitum.	2.4	2.4	2.4	1.21	0.99	1
Post-control (tpy)	762	---	N/A	N/A	N/A	N/A	N/A	N/A	379	656	938	1,656	739	485
Post-control (#/mmBtu)	0.25	0.13	0.11 (WDNR estim.)	0.10 (WDNR estim.)	0.19	0.162 (limit)	N/A	0.31 (limit)	0.20	0.17	0.24	0.15	0.13	0.13
% reduction	93	96.3	97.2 *	95.4 *	95% required (95-96% actual)	92% required (96% actual)	93% required	90% required (95% design)	92	93	90	87.6	83	83

N/A = Not Available

<u>* Notes on Greenidge (existing Turbosorp)</u>

- Was tested over 14-month period (Aug. 2007 to Sept. 2008)
- SO_2 inlet range 2.56 - 4.88 (avg. 3.62)
- SO_2 removal 96.3% (0.134 lb/mmBtu at stack)
- Limit is 0.19 lb/mmBtu, or ~ 94.8% removal)
- 93% SO_2 removal below 60 MWe (gross); > 95% above 60 MWe (gross); > 97% above 90 MWe (gross)
- Applicability to high-sulfur coal confirmed (96.5% removal for 4.8 lb/mmBtu over 11-hour period)

<u>* Notes on Deerhaven (existing Turbosorp)</u>

- Tested for 12-hour period
- SO_2 inlet 2.2 lb/mmBtu => removal 95.4% (Guarantee is 95% with 2.3 lb/mmBtu) SO_2 inlet 3.8 lb/mmBtu => removal 97.2%

- *Dry CFB FGD Cost and Visibility Improvement*

The cost estimates for the wet FGD and dry CFB FGD systems applied to boilers B26 and B27 are updated to reflect the SO_2 emission reductions. The visibility improvements are estimated using visibility improvement factors for SO2 reduction as developed in Section 5. Both the costs and visibility results are presented in Table 2.2.

The cost estimate for the Turbosorp system is updated to reflect a capital cost estimate received by Georgia Pacific from Babcock Power. The rough-order-of-magnitude (ROM) cost for the Turbosorp system includes a scope of supply for boiler units B26, B27 and B28. The ROM cost is 25.5 million dollars (M$). Babcock Power in the quote stated that installation costs are typically 45 to 55% of the Turbosorp capital cost. The Department applied a 50% installation cost to the 25.5 M$ capital cost which yields a total installed cost of 38.3 M$. To note, the Turbosorp ROM cost is considered conservative in the comparison as the quoted cost includes boilers B26, B27 and B28, whereas the wet FGD cost estimate included only B26 and B27. In looking at the results both the capital cost and deciview cost is twice as much for the wet scrubber compared to the dry scrubber. Because of this cost difference the Department maintains that going from dry CFB FGD to wet FGD is not substantiated and that BART is based on the application of dry CFB FGD technologies.

Table 2.2 Boiler B26 and B27 SO_2 Control Cost and Visibility Improvement

Control Option	Control Efficiency	Capital Installed (M$)	Annual Cost (M$)	$/ton	DV improvement [2]	M$/DV
Wet FGD	95%	55.9	32.1	3,490	1.27	25.3
	98%	55.9	32.9	3,440	1.32	24.9
Dry CFB FGD [1]	93%	38.3	16.0	1,580	1.23	13.0

[1] The Turbosorp ROM cost included B28, making the cost estimate conservative for the B26/B27 combined flue alone.
[2] Based on modeled maximum dv improvement average at Seney for 2002 – 2004 (see Section 5 "Visibility Improvement").

- *Summary of SO_2 BART Control and Visibility Improvement for Northern Class I Areas*

SO2 BART Boiler B26 & B27 - CFB FGD				
Control Efficiency 93%				
M$/year 16.0				
Controlled grams/sec 283				
	Seney		Northern Class I Areas	
	maximum	average	maximum	average
dv per gram/sec =	0.005	0.004	0.011	0.010
dv improvement =	1.49	1.23	3.06	2.79
M$/dv =	10.7	13.0	5.2	5.7

Northern Class I Areas = Isle Royale National Park, Seney Wilderness Area, Boundary Waters Canoe Wilderness Area and Voyageurs National Park.

3. SO_2 Base Emissions

The Department, for several reasons, determined that actual SO_2 base year emissions do not fully represent the appropriate basis for established BART SO_2 emission limitations. First, the default basis for determining BART compliance requirements, per BART guidelines, is applying the determined BART control efficiency against base year emissions (2002 to 2004). But BART guidelines also provide that existing conditions can be taken into consideration. Therefore it is reasonable to evaluate applicable fuels and the variability that may occur in emission levels. Second, the Department received comment that the BART determination should account for switching to low sulfur content fuels as compared to coke and high sulfur bituminous coals. For this control approach Georgia Pacific did identify various levels of fuel switching as a cost effective SO_2 control measure for both boilers B26 and B27[6].

Because of these issues and the integrated nature of operating Georgia Pacific's stack S10 boiler system, the Department has concluded it is appropriate to assess SO_2 fuel switching in context of base year uncontrolled SO_2 emissions. As a result, the Department determined that SO_2 base year emissions (uncontrolled) should reflect a "base" fuel consistent with boiler design and operation. In addition, that the sulfur content of the base fuel should reflect fuels that are reasonably obtainable on a long-term consistent basis. This approach is similar to a BACT determination for coal fired sources where a fuel type and maximum sulfur content is first established and then the BACT control efficiency is used to calculate the BACT emission limitation.

[6] Georgia Pacific, 2009, *Attachment B Engineering Analysis for Control Technology Options Green Bay Broadway Mill*. BART Analysis submitted to WDNR April, 2009.

- *Fuel Switching*

The results of Georgia Pacific's BART analysis for fuel switching at each of the BART boilers B26 and B27 are shown in Table 3.1. For both boilers, substituting bituminous coal for petroleum coke, with 5 to 6% sulfur, is considered relatively cost-effective at 755 and 1,500 $/ton for B26 and B27, respectively.

Table 3.1 Analysis of Fuel Switching for Reduction of SO_2 Emissions.

Boiler B26:

	Tons Reduced	Cost (M$/yr)	$/ton
Pet Coke to Bitum	869	0.7	755
Pet Coke to Low Sulfur Bitum	911	1.0	1,082
All fuel to Low Sulfur Bitum	1,333	1.6	1,224

Boiler B27:

	Tons Reduced	Cost ($/yr)	$/ton
Pet Coke w/ Low Fusion Bitum	950	1.4	1,505

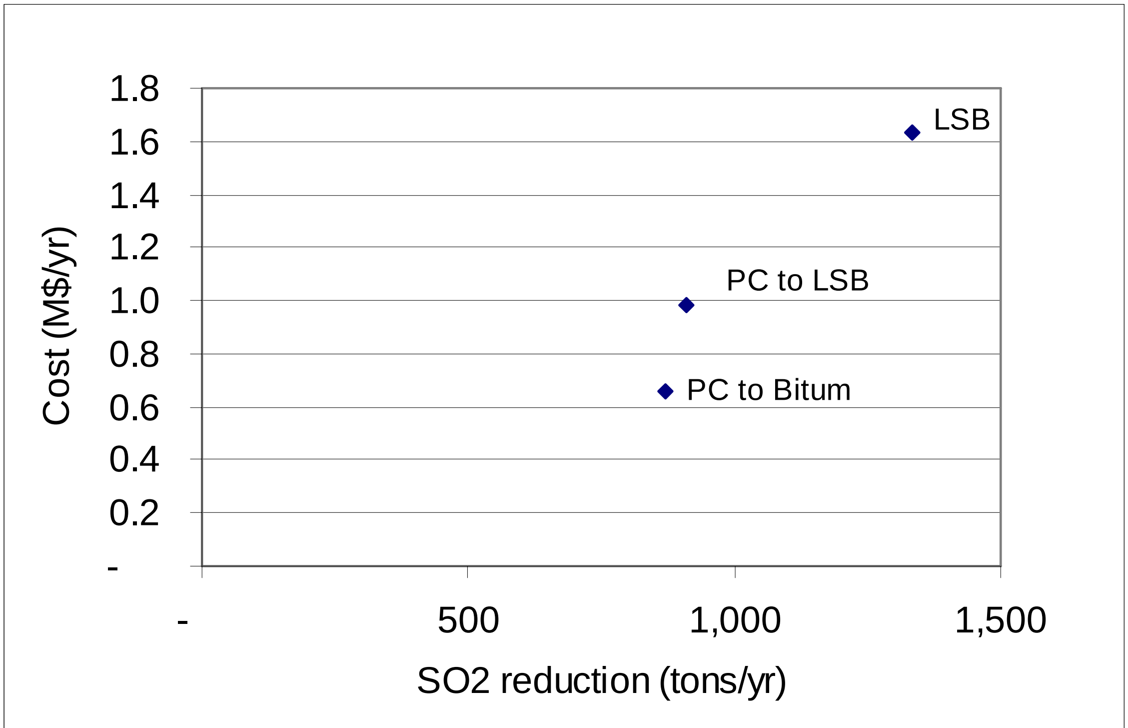
For boiler B27, the primary fuel switching alternatives are limited to replacing the petroleum coke with low fusion coal. Because the low fusion coal is important to maintaining necessary slagging characteristics in the boiler's cyclone furnace the Department does not consider other coals in fuel switching for boiler B27.

For boiler B26, an additional option of switching to low sulfur bituminous coal is available at an estimated 1,224 $/ton. Looking closer at boiler B26 fuel options, summarized in Figure 3.1, substituting low sulfur coal for either petroleum coal or for all fuels comes at an added expense. Still on a $/ton basis all of these options would be considered cost-effective under most regulatory requirements. As such, the affect of cost and emission reduction is further evaluated in context of the amended BART control efficiency.

When applying fuel switching options to boiler B26 followed by 93% FGD control there is a smaller difference in end emissions than if only fuel switching is employed. As shown in Table 3.2, with FGD, the various levels of fuel switching yield a difference of 61 to 93 tons per year in reduced emissions. This analysis shows that the majority of SO_2 reduction is achieved by eliminating the petroleum coke by substituting with the standard bituminous coal. This measure gains a 3% reduction in boiler emissions beyond scrubbed emissions. Going fully to low sulfur coals reduces emissions by a total of 93 tons or 4% beyond scrubbed emissions. Therefore there is only a 1% difference between the lower and maximum fuel switching options when employed with FGD. For this 1% additional reduction the cost is more than twice as much going from ~

0.6 $M to 1.6 $M per year. Therefore, switching coke fuels with standard bituminous coals is deemed to represent the appropriate level of fuel switching in addition to technology control options.

Figure 3.1 Boiler B26 Comparison of Fuel Switching for SO_2 reduction.



PC = petroleum coke; Bitum = standard bituminous coal; LS = low sulfur bituminous

Table 3.2 Boiler B26 SO_2 Emission Reduction from Fuel Switching after 93% Control (tons)

Fuel Switching Case	Emissions after Fuel Switch	Emissions after 93% control	Added Reduction by Fuel Switch	Marginal Fuel Switch Cost $/ton
Baseline Year Average	2,160	151		
Pet Coke to Bitum	1,291	90	61	10,780.03
Pet Coke to Low Sulfur Bitum	1,249	87	64	15,451.76
All fuel to Low Sulfur Bitum	827	58	93	17,488.92

- *"Base" Fuel Sulfur Content*

For boiler B27 (the cyclone boiler), low fusion bituminous coal is assumed as the "base" fuel. As previously stated the low fusion coal is a specific type of bituminous coal which produces specific slagging characteristics necessary to operating cyclone boilers. Because of this characteristic and its higher fuel price the Department concludes this fuel is not widely used by all coal boilers and will continue to be readily available into the future. However, the coal supply information available through the Department of Energy does not clearly distinguish between bituminous coal and low fusion bituminous coal, therefore an evaluation of the sulfur content for low fusion coal is not performed. Because of it's limited use and lack of specific data for low fusion coal, the Department concludes that the sulfur content of the current fuel used by Georgia Pacific represents low fusion coal sulfur content into the future. Georgia Pacific's BART analysis identified the current low fusion coal as containing 2.6% of sulfur by weight.

For boiler B26, the fuel switching analysis indicates standard bituminous coal is the appropriate "base" fuel. To determine the sulfur content of this base fuel the Department reviewed information for bituminous coal from mine sources historically utilized by Georgia Pacific. These coal sources are generally in the six-state region of Illinois, Indiana, Kentucky, Ohio, Pennsylvania, and West Virginia. Based on the Department of Energy's 2009 Quarterly Coal Report the bituminous coals supplied from these six states in 2009 ranged in average sulfur content of 1.53 to 3.68% sulfur[7].

More broadly the Department evaluated EPA's database of coal fuel characteristics compiled under 1999 EGU mercury information collection request (ICR). This ICR process required electric utilities to test fuel characteristics for each delivery of coal for an entire year which resulted in over 40,000 fuel samples. Therefore the ICR database is deemed very robust and representative of the availability of fuels. Analysis of the ICR data shows that a sulfur content of 2.5% by weight captures approximately 80% of bituminous coals fired by the electric utility sector on a heat input weighted basis (Figure 3.2). When looking at just the identified six-state region for Georgia Pacific coal sources (Figure 3.3) a sulfur content of 2.6% captures approximately 75% of the coal supplied to electric utilities from this region.

Figure 3.2 Sulfur Content of Bituminous Fired Coals, 1999 EGU ICR Database

[7] EIA, 2011, *Average Quality of Coal by State of Origin: Total (All Sectors)*, 2009, Energy Information Administration, http://www.eia.gov/cneaf/electricity/cq/cqaxlfilees3.html

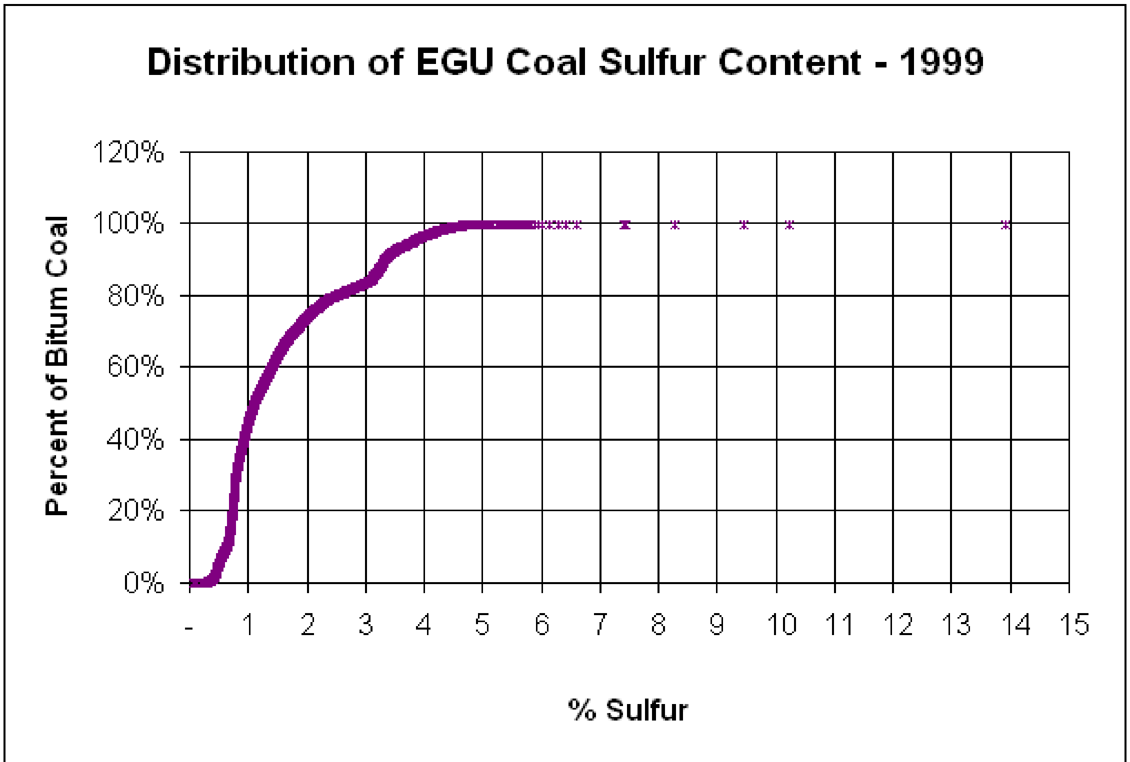
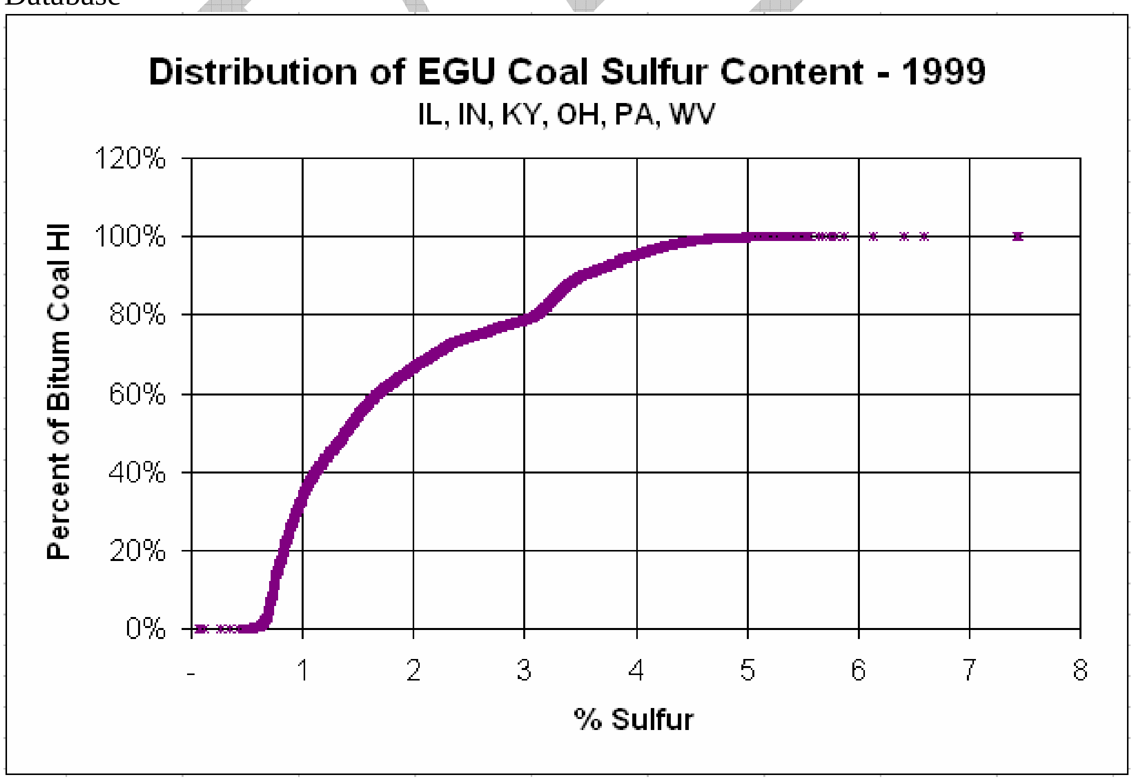


Figure 3.3 Sulfur Content of Bituminous Fired Coals – Six State Region, 1999 EGU ICR Database



Conclusion

The Department concludes that fuel switching is a cost-effective option to controlling SO_2 emissions. However, most of the effective reductions are captured by switching to standard bituminous fuels. Also to note is that other facilities, including cyclone boilers, have switched and operate fully on low sulfur powder river basin (PRB) subbituminous coals. The Department considers this option to be beyond the scope of BART. The majority of these facilities switching to PRB coal are large electric utilities which invested in long term delivery and supply logistics. These facilities have also had to significantly alter coal transfer and combustion related equipment in addition to adopting extensive coal management procedures in order to manage fire hazards associated with burning PRB coals. The Department finds that imposing these potential impacts with little additional SO_2 emissions reduction (fuel analysis to all low sulfur coal) is not warranted in context of the BART determination for this facility. Further, switching fuels to a base bituminous fuel is consistent with base design fuels of the boilers and therefore promotes efficient combustion and power production.

Therefore, to address reasonable fuel switching alternatives and expected availability of base fuels the Department finds that a base fuel for boiler B26 is represented by bituminous coal with up to 2.5% sulfur and that a base fuel for boiler B27 is represented by low fusion bituminous coal with up to 2.6% sulfur content.

- *Adjusted Base SO_2 Emissions*

The baseline year emissions for 2002 through 2004 are adjusted to reflect the sulfur content of the defined "base" fuels for each BART boiler. The base fuel assumption for boiler B26 is also applied to the remaining non-BART boilers, B24, B25, and B28, which are also stoker fired boilers. The specific applications of the defined base fuels are:

    - Low Fusion Bituminous Coal @ 2.6% sulfur – boiler B27
    - Bituminous Coal @ 2.5% sulfur – boilers B24, B25, B26 and B28

The basis for calculating the adjusted SO_2 emissions is the actual consumption of each fuel by boiler for each year. Each fuel not corresponding to the defined base fuel is replaced by the base fuel on a mmBtu for mmBtu basis. Boiler B27 fired a combination of low fusion bituminous coal and petroleum coke. The stoker boilers, including B26, fired a combination of bituminous coal, petroleum coke, and western low sulfur coals. Therefore the fuels replaced by the base fuels are petroleum coke and western low sulfur coal. In this calculation fuels consistent with the base fuel are not adjusted for sulfur content. The SO_2 emissions for each boiler are then recalculated for each fuel and summed. The results are used to calculate the adjusted 3 year average SO_2 emissions across the 2002 to 2004 base years. The adjusted base year SO_2 emissions are summarized in Table 3.3 along with actual base year emissions. Also presented for comparison are emissions based on each boiler's heat input and current permitted SO_2 limit. The details of base fuel substitutions and resulting emissions for each boiler are presented in appendix C.

As previously discussed the replacement of petroleum coke will reduce sulfur fuel content. Conversely, replacing low sulfur coal with the base fuel will increase fuel sulfur content and emissions for that portion of heat input. A basic premise in evaluating SO_2 requirements is that Georgia Pacific is permitted to emit up to 4.45 lbs/mmbtu from Stack S10 when another power boiler at the facility, boiler B29, is operating. This latter boiler is a newer fluidized bed boiler with 90% SO_2 scrubbing requirements which is used as a base load unit. When boiler B29 is not operating the SO_2 limit for Stack S10 increases to 4.55 lbs/mmBtu. This overall facility limit was set to avoid exceeding historic daily and annual SO_2 National Ambient Air Quality Standards (NAAQS). Applying this emission limitation to the base year heat input results in total annual SO_2 emissions of 13,905 tons for the BART boilers and 19,534 tons for the entire S10 stack, Table 3.3.

Typically the blending ratio of different coals and coke fuels with different heat contents is targeted to produce good firing characteristics. When the coke fuels are eliminated the amount of low sulfur coals that can be effectively blended will change in achieving good combustion. Because of these factors the Department concludes that a low sulfur fuel cannot be assumed when eliminating other historic fuel use (petroleum coke). Further, that when determining the BART emission requirements, a facility should not be penalized for historically emitting less than allowable emissions. Georgia Pacific clearly operated below their allowable SO_2 emissions level during the base years. Therefore, in light of these reasons, using a base fuel that represents reasonably anticipated operating conditions is an appropriate basis for establishing SO_2 emission requirements applicable to the Stack S10 boiler system.

Table 3.3 Base Year (2002 – 2004) Average Heat Input and SO_2 Emission Cases (tons)

	B26 & B27	**B24, B25, & B28**	**Total Stack S10**
Base Year Heat Input (mmbtu)	6,249,611	2,529,603	8,779,214
Base Year Actual	10,875	2,028	12,903
Adjusted Base Year	10,889	5,043	15,932
Permit Allowable Base Year*	13,905	5,628	19,534
BART Emissions (using Adjusted Base Year Emissions)**	757	5,043	5,800

* Facility allowable when boiler B29 is operating

**BART is 93% control to B26 and B27 Adjusted Base Year Emissions

4. Nitrogen Oxide (NOx) BART

The Department proposed 84% and 94% control efficiency of NOx emitted from boilers B26 and B27, respectively, in the draft BART determination. These proposed control levels were the result of assumed combustion modifications to each individual boiler followed by a regenerative selective catalytic reduction (RSCR) unit operating on the common flue stack. For the RSCR, 75% to 80% reduction was applied. In making the draft finding of RSCR as BART, the Department had also concluded that full-sized high-dust SCR configurations, capable of 80% or greater control, would likely be higher in cost and present challenging installation and operating conditions while garnering minimal additional visibility improvement.

In amending NOx BART, the Department maintains regenerative SCR is applicable for boiler B27. For the RSCR, the Department finds that 75% control efficiency is achievable and 70% control efficiency is appropriate in setting compliance requirements. The combustion modifications and RSCR applied to boiler B27 yield an overall compliance control efficiency 85%. The Department further finds that other combinations of technologies may result in comparable emission reductions in boiler B27 emissions. Because there is potential benefit, based on the BART five factors, the Department is setting NOx BART to be inclusive of these other options as well as the RSCR. On this basis the Department finds that 84% reduction is the NOx BART compliance control efficiency for boiler B27.

For boiler B26, the Department has determined that RSCR control is not applicable under BART. This conclusion is based on potential operating issues and costs when considering the RSCR installation in light of the existing equipment configuration. In absence of RSCR, the Department re-evaluated the control efficiency of combustion modifications and SNCR applicable to B26 – the next top-down tier of control options. This review identified higher control efficiencies than previously identified under the draft BART assessment. The result of this analysis is that NOx BART for boiler B26 is amended to 68% control based on combustion modifications and selective non-catalytic reduction (SNCR).

- *Application of Regenerative SCR*

The application of RSCR technology is further evaluated to address aspects of the existing equipment configuration which were not considered under the draft BART. Currently, flue gas from all boilers B24 through B28 exhausts to a common duct which then enters the existing fabric filter system. Just prior to the fabric filter system, the duct splits with flue gas traveling evenly to two parallel fabric filter units. The flue gas then exits each fabric filter unit in separate ducts and rejoins only after entering the stack structure. Previously the RSCR analysis accounted for a one flue duct configuration between the fabric filter system and the stack.

Babcock Power, the primary vendor of the RSCR system, provided a quote to Georgia Pacific for two separate RSCR trains, each treating an individual flue gas stream exiting the fabric filter[8]. Under this quote, one RSCR train treats approximately 260,000 acfm of flue gas flow. According to testing of maximum flow rates, boiler B27 can range up to 199,500 acfm and together with B26 can total 337,500 acfm (Appendix B). Because control equipment is typically designed to handle maximum flow rates, one RSCR cannot treat both B26 and B27 – RSCR acfm of 260,000 vs. boiler B26 & B27 337,500 acfm. On this basis, the installation of one

[8] Babcock Power Environmental, April 2010, *Green Bay Operations, Units 6, 7, 8 BPEI ROM Submittal 502477 – Rev 3*, submitted to Mr. Robert Bermke

RSCR is attributed to controlling boiler B27 emissions (duct 1) and the second RSCR (duct 2) for treating boiler B26 emissions.

The existing split flue duct and fabric filter system is also pertinent to evaluating SO_2 flue gas concentrations and associated impacts in operating the RSCR system.

If BART SO_2 requirements are met by scrubbing all flue gas (both ducts) at the same average control efficiency, then an RSCR on either duct will see SO_2 concentrations up to the BART limit of 1.01 lbs/mmbtu (Stack S10 emission limit, Table 6.2). A predominant issue at this emission level is that the SCR catalyst converts SO_2 to SO_3 causing visible plume and acidic flue gas conditions. Based on discussions with Babcock Power (BP) an SO_2 emission rate of 1.0 lbs/mmbtu will result in SO_3 concentrations of approximately 5.3 parts per million (ppm) @ 3% O2[9]. The Institute of Clean Air Companies indicates the target for avoiding plume is to keep SO_3 concentrations below 5 ppm.[10] Babcock Power indicates that plume issues need to be further evaluated if SO_2 concentrations to the RSCR are above 0.6 lbs/mmbtu. Therefore, SO_2 BART for Georgia Pacific at a default flue gas concentration of 1.0 lbs/mmBtu will generate visible plume and creates concern for overall technical feasibility of applying the RSCR under these conditions.

Another issue related to SO_2 and conversion to SO_3 is the formation of ammonium bisulfates (ABS) in the RSCR and downstream flue duct system. To avoid this issue at the 1.0 lbs/mmBTU emission rate, Babcock Power indicates that an RSCR would be operated at higher temperatures up to 650F as compared to 500F. Therefore at the higher SO_2 concentrations more energy will be required in reheating flue gas. The BP further states that even at 0.6 lbs/mmbtu (the draft BART SO_2 limit) the RSCR will require steam sootblowers and increased maintenance cycles. Therefore, higher SO_2 concentrations are not prohibitive to operating an RSCR but at a minimum do increase maintenance and operating cost throughout the system. In addition, any concentration higher than 0.6 lbs/mmbtu will have to be evaluated for plume generation and feasibility.

In utilizing the existing fabric filter system the most efficient and technically feasible approach to installing an RSCR is likely to operate the upstream FGD system on one side of the fabric filter system to maximum control levels. This approach is consistent with the Turbosorb system quote which specifies one unit for each side of the duct system - similar to the RSCR installations. This two system approach allows operating at different SO_2 control levels between the duct systems. Operating one scrubber at maximum levels can reduce SO_2 concentrations to 0.15 to 0.18 lbs/mmbtu in one flue gas duct. At these SO_2 emission levels the RSCR unit is clearly feasible and will see benefits in operation and life, minimized buildup of ammonium bisulfate and acid deposition, and elimination of any SO_3 plume generation. In Germany multiple tail-end SCR's after flue gas desulfurization have operated more than 10 years without replacing the SCR catalyst. Therefore this ability to focus SO_2 reductions to one flue gas duct allows RSCR to be a feasible and cost-effective NOx control option.

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[9] WDNR, March 2011, Personal communication with John Bowman concerning RSCR coal-fired installations, jbowman@babcockpower.com, Babcock Power Environmental, Worcester, MA.
[10] ICAC, 2009, *Selective Catalytic Reduction (SCR) Control of NOx Emissions from Fossil Fuel-Fired Electric Power Plants*, white paper prepared by NOx Control Technical Division, Institute of Clean Air Companies, Inc.

Conversely, where scrubber control is focused to the first duct the SO_2 concentrations in the second duct will likely be at least as high as the average BART emission limit of 1.01 lbs/mmBtu. In addition, SO_2 concentrations may range higher in the second duct if trimmed only to meet the overall emission requirement to both BART boilers. At these higher SO_2 concentration RSCR performance will degrade faster and SO_3 plume generation will clearly be a feasibility issue. Therefore the Department finds that applying RSCR to a second duct and to boiler B26 will incur significant technical issues including generation of visible plume.

- *Boiler B27 NOx Control*

As previously discussed, the RSCR control technology is further evaluated for controlling the Stack S10 split duct system. The manufacturer of the RSCR technology, Babcock Power, in the equipment quote stated capability for achieving 75% control of NOx emissions[11]. In determining the BART emission limitations the Department applied a RSCR compliance control efficiency of 70%. This difference in control efficiencies reflects a 7% compliance margin. In comparison, a 10% compliance margin was used by the Department in setting compliance requirements based on SCR controls under the Wisconsin NOx RACT rule, s. NR 428.22, Wis.Adm. Code.

Under the top-down approach, NOx control for boiler B27 is first overfire air combustion modifcations (OFA) followed by the RSCR equipment. The Department revised the OFA control efficiency after analyzing emissions data for OFA operating on cyclone boilers at the Nelson Dewey electric generating plant in Wisconsin[12]. The Nelson Dewey boilers are similar to boiler B27 both in size and in firing bituminous coals and petroleum coke. Based on the extensive experience of Alliant Energy, the operating utility, in optimizing and operating cyclone boiler OFA the Department deems this data to represent practical and achievable OFA control efficiencies. The analysis of emissions data shows OFA at Nelson Dewey achieving a 52% annual control efficiency. For purposes of determining BART compliance requirements the Department is applying 50% OFA control efficiency to boiler B27. Together the OFA and RSCR equipment result in 85% compliance control efficiency for boiler B27.

A primary question in sizing the RSCR technology is "what portion of the Stack S10 flue gas flow must be treated to address boiler B27 emissions". This is because the boiler B27 emission rate of 0.63 lbs/mmBtu (after OFA, Table 4.1) is diluted to 0.58 lbs/mmBtu when combined with the other boiler emissions. Therefore proportionally more flue gas has to be treated at the lower concentration to result in the same tons of boiler B27 NOx reduction.. After analysis, 97% of flue gas in one split duct needs to be treated by an RSCR operating at the upper 75% control efficiency. This means one of the split ducts and RSCR unit is dedicated to treating boiler B27 emissions. This apportionment of RSCR control requirement is corroborated in another way. During the baseline years, boiler B27 accounted for approximately 50% of the heat input to the boiler system and therefore equates to 50% of the overall system flue gas flow or one split duct.

[11] Babcock Power Environmental, April 2010, *Green Bay Operations, Units 6, 7, 8 BPEI ROM Submittal 502477 – Rev 3*, submitted to Mr. Robert Bermke.
[12] USEPA, 2011, NOx emissions data from the acid rain data base for 1990 – 2010, Clean Air Markets Division (CAMD).

In considering both of these factors, consistent with the finding for boiler maximum flue gas flow rates, the Department concludes that one full RSCR on one duct is dedicated to controlling boiler B27 emissions.

Control Alternatives

Since the RSCR requires significant capital and has associated impacts such as CO_2 emissions from re-heating flue gas, the Department further evaluated next-tier control options. These options included combinations of the OFA control with rich reagent injection (RRI), selective non-catalytic reduction (SNCR), and in-duct selective catalytic reduction (IDSCR). The combination of control options and identified control efficiencies are presented in Table 4.1. The primary control approach of OFA/RSCR is shown in the table as Case 1. The alternative options are discussed further below.

A NOx control technology specific to cyclone boilers is rich reagent injection (RRI) where urea is injected directly into the furnace. Because reagent is lost to combustion, the RRI approach uses more reagent than SNCR in reducing each NOx molecule. But the RRI approach has the benefit of reducing ammonia slip and avoiding ammonium bisulfate (ABS) impacts. The RRI can also be used with SNCR to achieve higher NOx reduction efficiency. The benefit here is that the SNCR can be applied with less ammonia slip and associated ABS impacts. Together the RRI/SNCR approach is capable of up to 60% NOx reduction[13]. In order for the RRI/SNCR to reach control levels similar to OFA/RSCR, the OFA system must be operated at a higher 60% control efficiency. Georgia Pacific identified this level of control for OFA in their BART analysis. However in the Department's experience 60% control is at the upper end of the control potential for OFA and likely decreases combustion efficiency of the boiler. It is for this reason that the 52% control efficiency, as demonstrated by the Nelson Dewey plant, is utilized in assessing the OFA/RSCR primary BART control option. Overall the OFA/RRI/SNCR (Case 2) may yield up to 84% control efficiency and an emission rate of 0.20 lbs/mmBtu for Boiler B27.

Table 4.1. Boiler B27 Top-Tier NOx Control Alternatives.

[13] FuelTech, 2011, *Rich Reagent Injection*, http://www.ftek.com/en-US/products/apc/rri/

Case		Controls	Control Efficiency	Combined Controls Emission Rate (lbs/mmbtu)
Case 1			uncontrolled	1.25
	OFA		50%	0.63
	RSCR		70%	0.19
		Overall control efficiency	85%	0.19
Case 2			unctrlled	1.25
	OFA		60%	0.50
	RRI / SNCR		60%	0.20
		Overall control efficiency	84%	0.20
Case 3			unctrlled	1.25
	OFA		55%	0.56
	RRI / SNCR		40%	0.34
	In Duct SCR		45%	0.19
		Overall control efficiency	85%	0.19

A third control alternative is the use of an in-duct SCR (IDSCR) consisting of 1 catalyst layer for up to 45% NOx reduction NOx[14]. The IDSCR is applied after the OFA and is designed to work with SNCR. The benefit of this approach is that the SCR can fit to the dimensions of the existing ductwork with little or no additional foundation requirement. In contrast, an SCR capable of 70 – 80% control with 3 catalyst layers will be approximately 16 x 16 x 50 feet high according to design criteria in the OAQPS control cost manual[15]. In comparison, the existing space between the boiler B27 economizer to the air-heater is approximately 8 feet in depth by 15 feet high. Reworking the duct runs and retrofitting a full SCR will require significant alteration of the existing air-heater and ducting configuration as well as building modifications.

The IDSCR can be more easily fit into the existing space and equipment configuration. Even before retrofit considerations, the capital costs of an IDSCR is approximately 30 to 70% of a conventional SCR[12]. Another benefit is that with one layer of catalyst the IDSCR will generate significantly less SO_3. Therefore ABS and acid gas plant impacts are greatly reduced. In addition, the RRI and SNCR reagent injection rates are balanced to yield just enough urea or ammonia slip for effective utilization of the IDSCR. This approach optimizes the efficiency of reagent utilization and further minimizes ABS impacts. Under this integrated approach the target control efficiency for the SNCR is up to 40% NOx reduction and for the SCR catalyst bed an

[14] FuelTech, 2011, *ASCR Advanced SCR*, http://www.ftek.com/en-US/products/apc/ascr/; *NOxOut Cascade*, http://www.ftek.com/en-US/products/apc/noxout-cascade/
[15] USEPA, 2002, *EPA Air Pollution Control Cost Manual – 6th Edition*, Office of Air Quality Planning and Standards, EPA/452/B-02-001

additional 45%. Therefore, to once again achieve control similar to the RSCR approach, the control efficiency of the OFA system must be increased from the base 50% to 55%.

Both control options, Case 2 and 3, are equipment configurations specific to Boiler B27 and have the benefit of not requiring up-front SO_2 emission reductions. In addition these options may significantly reduce energy requirements by eliminating flue gas reheat and reducing pressure losses compared to the RSCR catalyst bed. It should be noted that these control efficiencies for RRI, SNCR, and IDSCR are not based on specific quotes for the Georgia Pacific boilers. Rather this analysis represents the potential of these technologies to achieve reductions similar to the OFA/RSCR approach.

Cost-Effectiveness

Costs were initially estimated for OFA and RSCR systems in the draft BART determination. These costs are updated here to reflect vendor quotes and the applicability of cost factors as prescribed by the EPA air pollution control cost manual. The worksheets showing the updated costs for NOx control technologies are provided in Appendix B. Specifically, Babcock Power provided a system quote for installing two RSCR units to the Georgia Pacific Stack S10 system. This quote included a capital cost, an estimate that installation costs run 20 – 30% of capital costs and provided specific operating parameters related to reagent usage and utility requirements. This information is applied to develop the cost of controlling boiler B27 emissions (one flue duct). The cost of the overfire air system is also revised to reflect a system quote by Combustion Components Associates (CCA) specifically for installation to boiler B27.

Costs are developed for RRI and SNCR systems based on a quote by CCA for installation to boiler B27. The cost for the SNCR/IDSCR system approach is based on the actual installation cost for this type of system to unit 4 of the AES Greenidge facility[16]. Since the SCNR/IDSCR cost is not based on a specific quote for Boiler B27 the result is considered a scoping cost.

The resulting costs and emission reductions for the evaluated technologies are provided in Table 4.2. The cost-effectiveness of visibility improvement (M$/dv) is calculated for the Seney Class I area using a factor of 0.005 deciview per grams/sec of reduced NOx emissions (Table 5.2). This improvement factor represents the average of the maximum impact registered in each of the base years when applying the amended BART emission limitations. In comparison, the improvement factor in total for all four class I areas combined is 0.008 deciview per grams/sec.

The results of the analysis show that the OFA/RSCR system yields 0.43 deciview improvement in visibility for Seney at a cost-effectiveness of 1,215 $/ton and 6.6 M$/DV. The alternative control options show a potential for visibility improvement similar with lower associated cost than the OFA/RSCR. To gauge the overall visibility improvement from each control option the maximum and average visibility impact is estimated for the northern Class I areas as well. These results are presented in Table 4.2 and Figure 4.1.

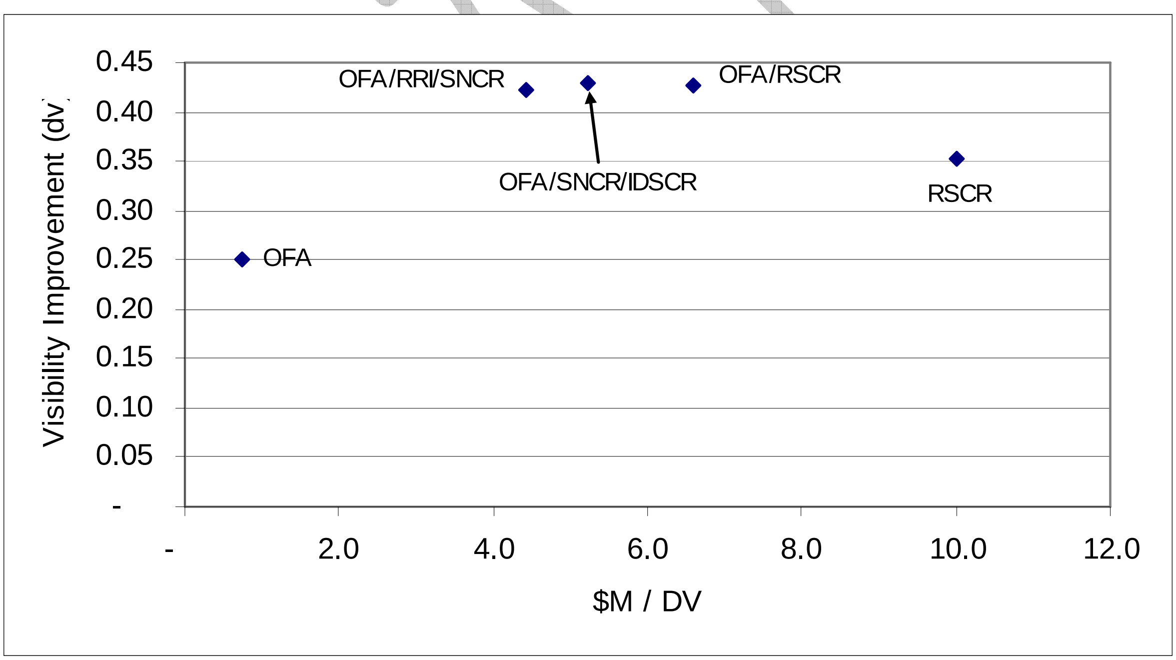
[16] USDOE, 2009, *Greenidge Multi-pollutant Control Project - Final Report of Work Performed*, DE-FC26-06NT41426

This analysis clearly shows that the similar visibility improvement may be achieved with several control options other than OFA/RSCR. These options also have the potential to reduce cost and may minimize energy and plant impacts. Therefore the Department concludes that the minimum control efficiency across these control options of 84% NOx reduction represents BART for boiler B27. This control level does not presume that OFA/RSCR in not BART. However it does presume that this level of control allows various options in addition to OFA/RSCR in meeting BART.

Table 4.2 Boiler B27 Control Cost and Visibility Improvement for Seney.

Control Technology	Control Efficiency	Tons Controlled	Capital Installed (M$)	Annual Cost ($)	$/ton	Visibility Improvement (dv)	M$/DV
OFA	50%	1,365	1.2	187,161	137	0.25	0.7
RSCR	70%	1,910	8.1	3,519,674	1,842	0.35	10.0
OFA / RSCR	85%	2,320	9.3	2,818,927	1,215	0.43	6.6
OFA/RRI/SNCR	84%	2,292	4.0	1,872,794	817	0.42	4.4
OFA/SNCR/IDSCR	85%	2,324	10.9	2,242,797	965	0.43	5.2

Figure 4.1 Boiler B27 Control Options – Visibility Improvement for Seney and Cost-Effectiveness.



- *Boiler B26 NOx Control*

As previously discussed, the Department deems the RSCR as not representing BART control for boiler B26. However, to evaluate this issue further, a full list of controls including RSCR is carried forward in evaluating cost-effectiveness of technologies for Boiler B26.

In absence of applying RSCR control, the next tier of top-down NOx control identified for boiler B26 is a combination of flue gas recirculation (FGR) and over-fire air (OFA) combustion modifications followed by selective non-catalytic reduction (SNCR). In the draft BART analysis the combination of FGR and OFA was initially rated to achieve a minimum 20% reduction of NOx emissions. The 20% control level ensured no impact to combustion quality and is deemed appropriate when followed by the RSCR control. However, a 40% reduction is achievable for stoker boilers[17]. To determine if this full control potential can be achieved will require additional engineering and computer fluidized dynamic (CFD) modeling of the combustion process. Without this level of analysis, the Department is applying 35% compliance control efficiency for OFA/FGR as applied to boiler B26.

SNCR technology is successfully demonstrated for up to 50 to 70% long term reduction of NOx emissions[18]. Similar to OFA/FGR design, to determine the SNCR maximum achievable control efficiency for boiler B26 requires engineering and CFD modeling analysis. In this case the depth of the control is dependent on boiler dynamics, reagent mixing conditions, residence time, temperature regime and ammonia injection rates which do not cause ammonium bisulfate buildup or acid conditions. Therefore, without CFD modeling, a SNCR compliance control efficiency of 50% is applied to boiler B26. The 50% control efficiency also represents the upper end of typical control ranges while the Department anticipates that significant reagent slip and plant impact will occur when going to higher control efficiencies.

Together the discussed OFA/FGR and SNCR result in a total compliance control efficiency of 68%. Applying this control efficiency to the uncontrolled emission rate, 0.68 lbs/mmbtu, yields a BART emission rate limitation of 0.22 lbs/mmbtu for boiler B26. Boiler B26's uncontrolled emission rate is revised versus the draft BART analysis based on current NOx emissions data.

The control technologies evaluated for boiler B26 are listed in Table 4.4 with estimated cost-effectiveness and visibility improvement results. The costing worksheet for each technology is provided in Appendix B. The costing of the RSCR control option is revised here using the same methods discussed for boiler B27. The costs of the OFA, FGR, and SNCR technologies are developed using costs and operating factors quoted by Combustion Components Associates (CCA) for installation to boiler B26. Control efficiencies provided in the CCA quote are lower than applied in this analysis; therefore urea injection and utility consumption rates are scaled accordingly. The application of default cost factors used in the draft BART analysis are adjusted to reflect guidance provided in the EPA air pollution control cost manual. For all technologies the visibility improvement for Seney is estimated using a factor of 0.005 deciview per grams/sec reduced (Table 5.2)

Table 4.4 Boiler B26 Control Cost and Visibility Improvement for Seney.

[17] Tim Loviska, 2009, personal communication, Tloviska@detroitstoker.com
[18] ICAC, 2008, *Selective Non-Catalytic Reduction (SNCR) for Controlling NOx Emissions*, white paper prepared by SNCR Committee, Institute of Clean Air Companies, Inc.

Control Technology	Control Efficiency	Tons Controlled	Capital Installed (M$)	Annual Cost ($)	$/ton	Visibility Improvement (dv)	M$/DV
OFA/FGR	35%	224	1.7	244,797	1,093	0.05	5.3
SNCR	50%	320	2.7	681,223	2,128	0.07	10.4
OFA/FGR/SNCR	68%	432	4.4	807,098	1,868	0.09	9.1
RSCR	70%	448	8.1	2,160,437	4,821	0.09	23.6
OFA/FGR/RSCR	81%	515	9.9	1,893,858	3,675	0.11	15.6

The analysis shows that all of the evaluated control options are cost-effective with a maximum visibility improvement demonstrated by the OFA/FGR/RSCR system at 3,675 $/ton and 15.6 M$/DV. These results also show that the majority of visibility improvement is captured by the OFA/FGR/SNCR system at 68% control. The cost of this system is estimated at 1,868 $/ton and 9.1 M$/DV or almost half that of the RSCR based control approach. Figure 4.2 shows that the difference in visibility improvement between these two options is a little more than 0.01 deciview. This difference is approximately 10 – 15% of additional improvement garnered by the RSCR system at approximately twice the cost. This same point in cost difference is demonstrated in Figure 4.3 which looks at the capital required by each technology option. These factors point to the RSCR based controls as beyond the knee in the curve for achieving visibility improvement in a cost-effective manner under BART.

Conclusion

A number of factors, including cost-effectiveness and visibility improvement, demonstrate that OFA/FGR/SNCR at 68% control efficiency represents NOx BART for boiler B26. This premise is the result of the RSCR system garnering a small increment in visibility improvement relative to the SNCR based approach. In this context the RSCR system has a higher energy penalty and emits more CO_2 as compared to the SNCR based system. In addition, the OFA/FGR/SNCR system is not anticipated to incur significant challenges for installation or operation as compared to the RSCR. Lastly, for RSCR to be feasible may require focused SO_2 controls that may be dedicated for RSCR feasibility to boiler B27.

Figure 4.2 Boiler B26 Control Options – Visibility Improvement for Seney and Cost-Effectiveness

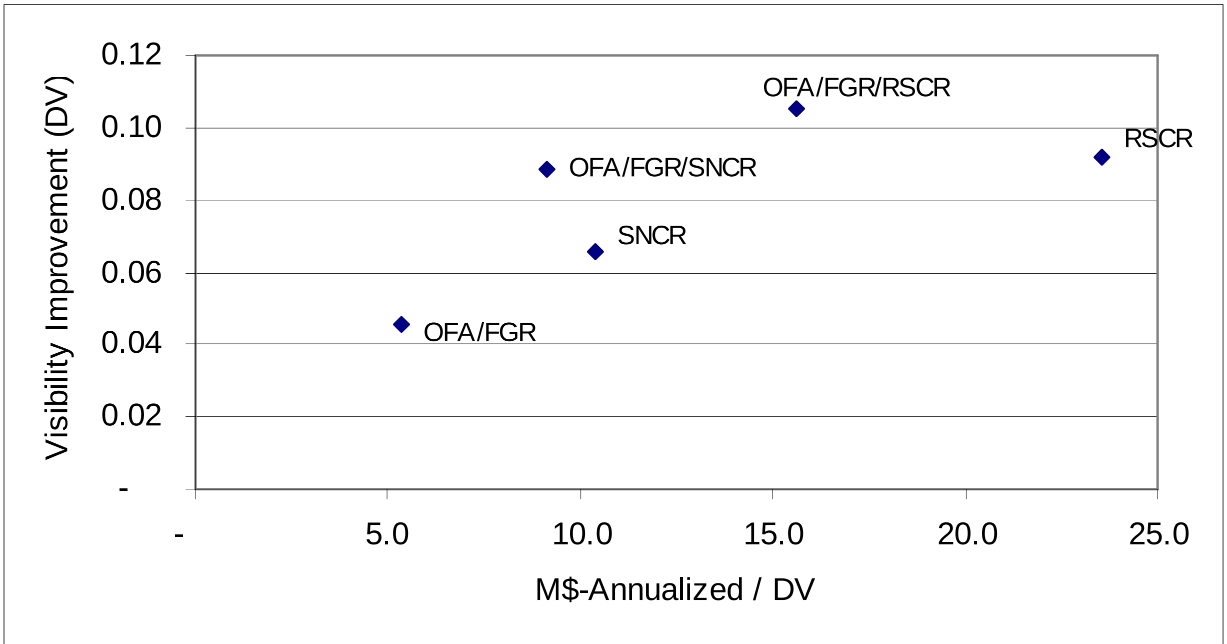
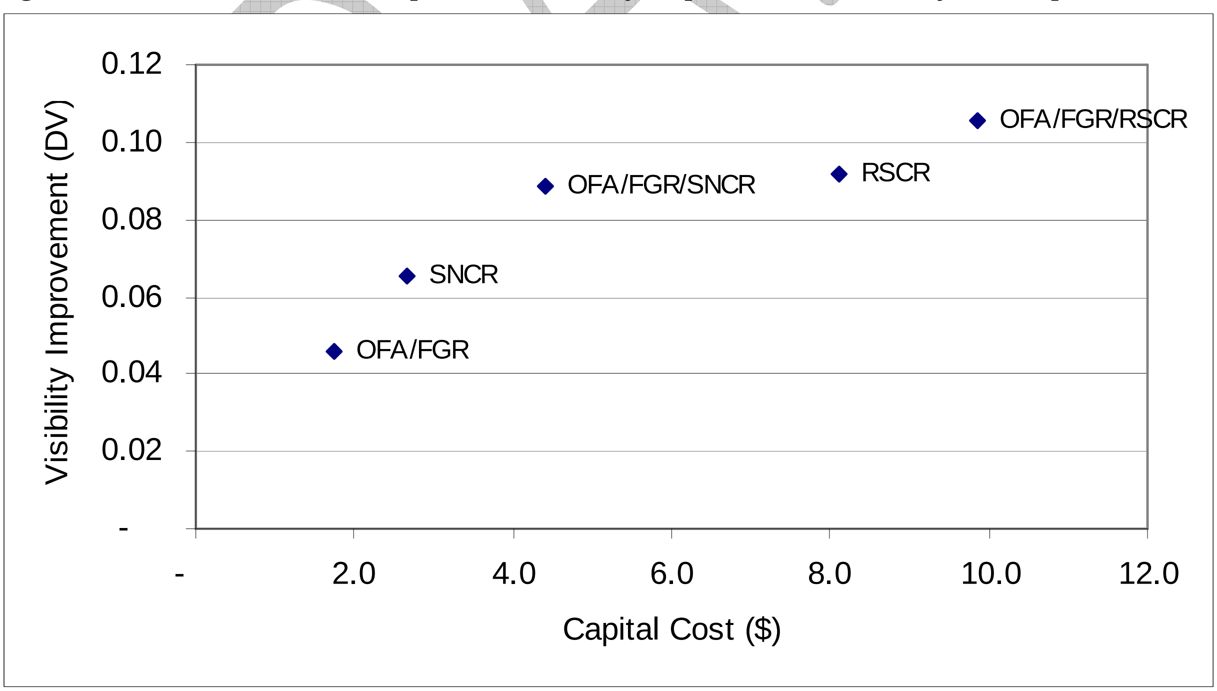


Figure 4.3 Boiler B26 Control Options – Visibility Improvement for Seney and Capital Cost



<u>Summary of NOx BART for Boilers B26 and B27 and Visibility Improvement</u>

NOx BART Boiler B27 - OFA + RSCR				
Control Efficiency 84%				
M$/year 2.8				
Controlled grams/sec 87				
	Seney		Northern Class I Areas	
	maximum	average	maximum	average
dv per gram/sec =	0.009	0.005	0.012	0.008
dv improvement =	0.76	0.42	1.02	0.71
M$/dv =	3.71	6.68	2.76	3.96

Northern Class I Areas = Isle Royale National Park, Seney Wilderness Area, Boundary Waters Canoe Wilderness Area and Voyageurs National Park.

NOx BART Boiler B26 - OFA/FGR + SNCR				
Control Efficiency 68%				
M$/year 0.6				
Controlled grams/sec 18				
	Seney		Northern Class I Areas	
	maximum	average	maximum	average
dv per gram/sec =	0.009	0.005	0.012	0.008
dv improvement =	0.16	0.09	0.22	0.15
M$/dv =	3.96	7.12	2.94	4.23

Northern Class I Areas = Isle Royale National Park, Seney Wilderness Area, Boundary Waters Canoe Wilderness Area and Voyageurs National Park.

NOx BART Combined Boilers B26 & B27				
M$/year 3.5				
Controlled grams/sec 105				
	Seney		Northern Class I Areas	
	maximum	average	maximum	average
dv per gram/sec =	0.009	0.005	0.012	0.008
dv improvement =	0.92	0.51	1.24	0.86
M$/dv =	3.75	6.75	2.79	4.01

Northern Class I Areas = Isle Royale National Park, Seney Wilderness Area, Boundary Waters Canoe Wilderness Area and Voyageurs National Park.

5. Visibility Improvement Related to BART

The Department performed CALPUFF modeling to assess visibility improvement achieved under the amended BART requirements. The modeled emission cases are based on the maximum actual emissions during the baseline years for the combined stack S10. The base uncontrolled emission rates, in grams per second, for each pollutant are provided in the draft BART determination, Table C10.

To provide the emissions model input for the BART case a surrogate control efficiency is applied to the Stack S10 maximum day emissions. This surrogate control efficiency is calculated from the difference between the BART annual mass cap emission limitation (Table 6.2) compared to the annual actual average emissions during the baseline years. The applied surrogate Stack S10 percent reduction is 70% for NOx and 57% for SO_2. The resulting maximum day controlled emission rates are then modeled for every day in 2002 to 2004.

In looking at the visibility improvement from BART one measure is the count of days showing visibility impact above 0.1 and 0.5 deciviews. The total number of days at each northern Class I area above these thresholds are shown in Table 5.1. These results show that Seney realizes the largest reduction of days for each case with the total number of days with impact above 0.5 deciview reduced by 29 to 34 days over the baseline years. Above the 0.1 deciview threshold the number is reduced by 29 to 33 days over the baseline years.

Table 5.1 Days of Visibility Impact after BART for the Northern Class I Areas.

Number of days with delta-deciview => 0.1

Uncontrolled Emissions

	2002	2003	2004
bowa	25	28	44
isle	34	51	52
sene	107	118	113
voya	10	13	20

BART

	2002	2003	2004
bowa	18	16	25
isle	26	36	32
sene	78	85	82
voya	4	4	6

Reduced Days of Impact with BART

	2002	2003	2004
bowa	7	12	19
isle	8	15	20
sene	29	33	31
voya	6	9	14

Number of days with delta-deciview => 0.5

Uncontrolled Emissions

	2002	2003	2004
bowa	7	7	13
isle	14	19	17
sene	41	53	48
voya	2	0	2

BART

	2002	2003	2004
bowa	2	2	2
isle	6	6	3
sene	12	22	14
voya	0	0	0

Reduced Days of Impact with BART

	2002	2003	2004
bowa	5	5	11
isle	8	13	14
sene	29	31	34
voya	2	0	2

Another metric in comparing visibility impact is the maximum daily impact modeled in each year shown. These results are summarized in Table 5.2. The "maximum" is the highest value modeled in any of the three baseline years 2002 to 2004. The "average" is the average of the maximum value modeled in each base year – therefore an average of the maximum impact for 2002, 2003, and 2004. These modeling results show for Seney that BART reduces the highest maximum impact seen over the three base years by 2.68 deciview. The average impact improves by 2.02 deciview.

A total maximum and average value is also presented for all four northern Class I areas. This total value represents the sum of the maximum modeled for each individual class I area. Although the maximum impact is not expected to occur at all sites at the same time this metric is a means of measuring relative changes. The maximum value across the northern areas improved by 5.03 deciview and on average improved by 4.19 deciview.

Modeling runs were also performed to assess the visibility improvement under BART related to the individual pollutants, shown in the Table 5.2 for SO_2 and NOx. This information is used to calculate a visibility improvement factor in deciview improvement per gram/sec of pollutant reduced. These factors are then used in the visibility assessments of the individual control technologies when performing the BART evaluations (Sections II.2 and II.4). The "average" value is used for these technology evaluations as it represents a reasonably expected improvement rather than the maximum seen over all three baseline years. For example, to calculate visibility improvement at Seney the average value of 0.005 grams/sec is applied for NOx and 0.004 grams/sec is applied for SO_2. To note though, also shown in the Table 5.2, the sum of visibility improvement for each pollutant does not sum to total improvement when reducing both pollutants together. Thus using the individual pollutant visibility improvement factors under-estimates the total visibility improvement for the pollutant in context of the entire BART requirement.

Table 5.2 Modeled Maximum Daily Impact (dv) for 2002, 2003, and 2004

Visibility Case / Paramenter		Seney		Northern Class I Areas	
		Maximum	Average	Maximum	Average
Uncontrolled Emissions (max day)		5.38	4.14	9.67	8.12
Residual Visibility Impact (RVI)	BART	2.70	2.12	4.64	3.93
	SO2	3.89	2.91	6.61	5.34
	NOx	4.54	3.67	8.54	7.34
Visibility Improvement (VI) Result of "Uncontrolled" - "RVI"	BART	2.68	2.02	5.03	4.19
	SO2	1.49	1.23	3.06	2.79
	NOx	0.84	0.47	1.13	0.79
	sum of SO2 & NOx	2.33	1.70	4.19	3.57
Visibility Improvement / Gram Pollutant; Result of RVI / grams per sec reduced	BART	0.007	0.005	0.013	0.011
	SO2	0.005	0.004	0.011	0.010
	NOx	0.009	0.005	0.012	0.008

Maximum = Maximum Daily Impact modeled for the base years (2002 – 2004)
Average = Average of each base year maximum daily impact.

6. Emission Limitations and Compliance Requirements

BART emission limitations are determined for each boiler and each pollutant SO_2 and NOx in two forms: 1) emission rate limitations (lbs/mmbtu) and, 2) allowable mass emissions (tons). The permit allows BART requirements to be satisfied by demonstrating compliance with either emission limitation format.

The BART emission rate limits are determined by applying the BART control levels to the uncontrolled base emission rates. For SO_2, the base uncontrolled emission rates reflect the adjusted base year emissions shown in Table 4.1. This base information and resulting BART emission rate limits, on a 30 day rolling basis, for boilers B26 and B27 are presented in Table 6.1.

Georgia Pacific can also comply with the mass cap limits for each boiler also shown in Table 6.1. The 12 month mass cap is the result of applying the BART emission rate limit to the average of the annual heat input for each boiler during the baseline years 2002 to 2004. This limit is viewed as being consistent with achieving a long-term average BART level of control. The 30 day limit is set by applying the emission rate limit to the maximum day heat rate for each boiler, B26 and B27, and then multiplying by 30 days. The 30 day rolling mass cap is set in tandem with the 12 month mass cap to ensure that visibility is protected on a daily basis. This short term limit is then consistent with the visibility improvement modeled using maximum day emissions.

Table 6.1 BART Control Level and Requirements for Boilers B26 and B27.

Stack S10 Boilers	Uncontrolled Emission Rate (lbs/mmbtu)	BART Emission Requirements			
		Control Level	30 Day Rolling Emission Rate Limitation (lbs/mmbtu)	Tons Emitted in any 12 Month Period	Tons Emitted in any 30 Day Period
SO2					
B26	3.79	93%	0.27	254	33
B27	3.35	93%	0.23	502	47
NOx					
B26	0.68	68%	0.22	207	27
B27	1.25	84%	0.20	437	41

As an alternative the permit allows Georgia Pacific to demonstrate compliance with Stack S10 emission limitations in lieu of the individual boiler requirements. Similar to the individual boiler limits, Stack S10 compliance can be demonstrated by meeting either an emission rate limitation or a mass cap limitation. The Stack S10 emission limitations are shown in Table 6.2.

The mass requirement for Stack S10 incorporates the mass cap limits for boilers B26 and B27 as presented in Table 6.1. Uncontrolled emissions are then added for the non-BART boiler B24, B25, and B28 based on uncontrolled base year emissions for 2002 to 2004. As for the BART boilers, the non-BART boiler uncontrolled SO_2 emissions reflect the adjusted base year emissions shown in Table 3.1. The NOx emissions for the non-BART boilers reflect the actual average reported emissions during the baseline years. The annual mass emissions are then totaled across the BART and non-BART boilers to determine the 12 month rolling cap. A 12 month average emission rate is then calculated from the mass cap and total Stack S10 base year heat input. The 30 day mass cap is then calculated by multiplying the 12 month average emission rate by the maximum emission day heat input for Stack S10 and multiplying by 30.

Under the emission rate compliance approach both a 30 day and 12 month rolling average emission rate applies to Stack S10. Once again, the 30 day limit is required to ensure a minimum visibility improvement on a continuous basis. In this case, where additional capacity can be utilized beyond that demonstrated and modeled for the maximum day emissions a different approach is used to determine stack emission rate limits. The mass cap requirements are consistent with annual average (12 month) and maximum day (30 day) heat inputs during the baseline years. If the associated average emission rates or BART emission rates are allowed and the boilers are used at high capacity rates then total emissions will exceed the BART mass caps. To ensure the mass caps are not exceeded, resulting in higher visibility impact, a surrogate maximum heat input representing 95% of Stack S10 boiler capacity is utilized to calculate emission rate limits. Therefore, mass cap requirements in Table 6.2 are divided by this boiler system maximum heat input for 30 days and 12 months to calculate the associated emission rate limitations also shown in Table 6.2.

Table 6.2 Alternative BART Compliance Requirements for Stack S10

Pollutant	Mass Cap Requirement		Emission Rate Requirement	
	Tons Emitted in any 12 Month Period	Tons Emitted in any 30 Day Period	12 Month Rolling Emission Rate Limitation (lbs/mmbtu)	30 Day Rolling Emission Rate Limitation (lbs/mmbtu)
SO2	5,800	761	1.01	1.53
NOx	1,200	141	0.21	0.28

7. SO_2 and NOx Default Trading Program

Under the state BART rule, s NR 433.06, Wis. Adm. Code, sources may trade emissions in complying with BART requirements. In using a trading approach, a facility is not allowed to trade with other facilities and must account for other sources at the facility serving the same function - thus avoiding load shifting. The rule also requires that any trading program fulfill two criteria: first, an additional 10% reduction beyond the BART requirement for the pollutant being offset with emissions trading. Second, any trading of emissions must result in visibility improvement equivalent to BART emission requirements plus the 10% additional reduction.

- *Permit Requirements*

An emission trading program is established in Georgia Pacific's permit which meets the criteria of s. NR 433.06. The program anticipates trading SO_2 emission reductions beyond BART in lieu of NOx emission reductions and is structured using the Stack S10 mass cap to account for all similar sources. In this approach the additional 10% reduction is applied to both the NOx 30 day and 12 month mass cap requirements to yielding the required BART-Trade mass cap requirements, Table 7.1. Under the Trading program the SO_2 mass cap requirement is restated and acts as the minimum requirement for SO_2 at any time during the trading program. Therefore, this program allows for one-way trading – SO_2 for NOx. To meet the second criteria under trading for meeting equivalent visibility improvement the trading program requires that two tons of SO_2 must be used to offset every ton of required NOx reduction. The analysis establishing visibility equivalency under this trading ration is presented below.

Table 7.1 BART-Trade Requirements.

Pollutant	Mass Cap Requirement		Trading Ratio
	Tons Emitted in any 12 Month Period	Tons Emitted in any 30 Day Period	
SO2	5,800	761	
NOx	1,080	127	Requires 2 tons SO2 reduction for each ton of NOx over Emission Cap.

Note: NOx 12 month mass cap = 1,200 tons – 120 tons (10%), NOx 30 day mass cap = 141 tons – 14 tons (10%).

- *Evaluation of Visibility Equivalency*

To determine visibility equivalency, the Department performed CALPUFF modeling reflecting BART Trading mass cap requirements. The Department then performed CALPUFF modeling of varying NOx and SO_2 control levels at different trading ratios of SO_2 for NOx. The levels of NOx reduction tested (21%, 39%, and 54%) relate to control efficiencies of different control technologies or options other than the assumed BART controls (70%). These control efficiencies are determined for Stack S10 emissions in the same manner as for the BART visibility evaluation, Section II.5. The SO2 control levels are the result of offsetting the remaining NOx reduction requirements under the specified trading ratios. The emissions trading cases modeled by the Department are listed in Table 7.2.

Table 7.2 CALPUFF Modeling Cases for Evaluating Emissions Trading

Modeling Scenario	Control Case	Trading Ratio (SO2:NOx)	Emission Rate (grams / sec)		
			SO2	NOx	PM
BART-Trade	1 - NOx 70% control, SO2 57% control		221.4	41.0	17.2
Sensitivity Runs	2 - NOx 39% control, SO2 67% control	1:1	169.9	86.3	17.2
	3 - NOx 39% control, SO2 86% control	3:1	72.1	86.3	17.2
	4 - NOx 54% control, SO2 71% control	3:1	149.3	65.1	17.2
	5 - NOx 39% control, SO2 76% control	2:1	123.6	86.3	17.2
	6 - NOx 54% control, SO2 67% control	2:1	169.9	65.1	17.2
	7 - NOx 21% control, SO2 72% control	1:1	144.1	111.8	17.2
	8 - NOx 21% control, SO2 87% control	2:1	66.9	111.8	17.2

In determining equivalent visibility improvement for trading the Wisconsin BART rule, under provision s. NR 433.06(1)(b)2, Wis. Adm. Code, states that the demonstration shall meet the following test:

> "*The improvement in visibility shall be demonstrated by comparing the 20% best days of visibility and the 20% worst days of visibility in at least the 4 mandatory Class I federal areas nearest to the source and for each calendar year 2002, 2003 and 2004.*"

The Department performed modeling for all Class I areas, but the evaluation of equivalency and trading ratios results presented here focuses to Seney as this area receives the greatest visibility impact. In the analysis the Department is also sensitive to seasonal differences which cause variation in impact related to each pollutant. Specifically, in this case, NOx emissions exhibit stronger visibility impairment during colder months than during the summer. Conversely, the impact related to SO_2 emissions strengthens during warmer periods and as the availability of ammonia increases. Because of such effects the visibility equivalency is compared both on an overall annual basis but also for shorter 30 day periods on an ongoing basis.

As a first assessment, the number of days of impact for all class I areas are compared between the various cases. Shown in Table 7.3, a trading ratio of 1 ton SO_2 for 1 ton of NOx increases the total number of impact days in Case 2 and 7 (bolded values). The 1:1 ratio cases also show a modeled increase in the maximum day impact (bolded values) for the Seney Class I area, Table 7.4. Based on increases in both of these visibility metrics the Department concludes that a trading ratio of 1:1 is insufficient for achieving equivalent visibility improvement.

Table 7.3 Number of Days with Visibility Impact > 0.1 Deciview.

Case	Class I Area	No. of Days > 0.1 Deciview			Trading Ratio (NOx:SO2)
		2002	2003	2004	
1 (BART-Trade)	bowa	18	15	25	
	isle	25	35	31	
	sene	75	84	79	
	voya	4	4	5	
2	bowa	16	14	25	1 to 1
	isle	25	33	31	
	sene	**77**	83	**83**	
	voya	3	3	5	
3	bowa	10	9	15	1 to 3
	isle	19	24	22	
	sene	56	68	56	
	voya	2	0	3	
4	bowa	11	13	22	1 to 3
	isle	21	30	29	
	sene	69	80	69	
	voya	3	3	3	
5	bowa	11	13	19	1 to 2
	isle	22	29	28	
	sene	70	80	70	
	voya	3	3	3	
6	bowa	16	13	25	1 to 2
	isle	24	32	29	
	sene	72	81	77	
	voya	3	3	4	
7	bowa	15	13	26	1 to 1
	isle	25	33	33	
	sene	**78**	**85**	**83**	
	voya	3	3	5	
8	bowa	10	10	15	1 to 2
	isle	21	27	25	
	sene	61	70	62	
	voya	2	1	3	

bowa = Boundary Waters Canoe Wilderness Are
isle = Isle Royal National Park
sene = Seney Wilderness Area
voya = Voyageurs National Park

Table 7.4 Maximum Daily Impact for Each Base Year

Case	Maximum Deciview			Trading Ratio (SO2:NOx)
	2002	2003	2004	
1 (Bart-Trade)	2.56	1.33	2.14	
2	**2.80**	1.32	**2.15**	1 to 1
3	2.06	0.87	1.45	1 to 3
4	2.35	1.12	1.83	1 to 3
5	2.45	1.11	1.83	1 to 2
6	2.51	1.21	1.98	1 to 2
7	**2.94**	1.32	**2.19**	1 to 1
8	2.38	0.98	1.64	1 to 2

Moving to the 2:1 trading ratio cases 5, 6, and 8 there is no increase in either the number of days or maximum daily impact when compared to the BART-Trading case 1. To screen more closely for potential visibility equivalency the modeled daily maximum impact across 2002 to 2004 is plotted for these cases, Figures 7.1, 7.2, and 7.3. This comparison shows that the residual visibility impacts compare well between the BART-Trading and 2:1 trading ratio cases.

Figure 7.1 Daily Maximum Modeled Impact, 2002 – 2004: BART-Trade vs. Case 5.

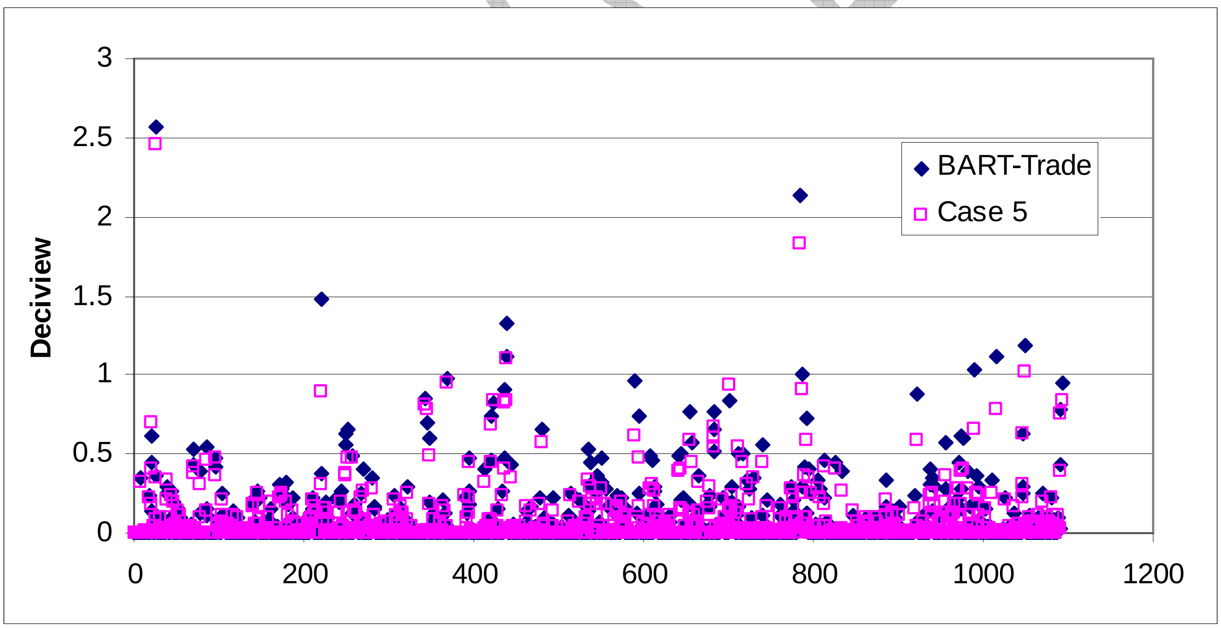


Figure 7.2 Daily Maximum Modeled Impact, 2002 – 2004: BART-Trade vs. Case 6.

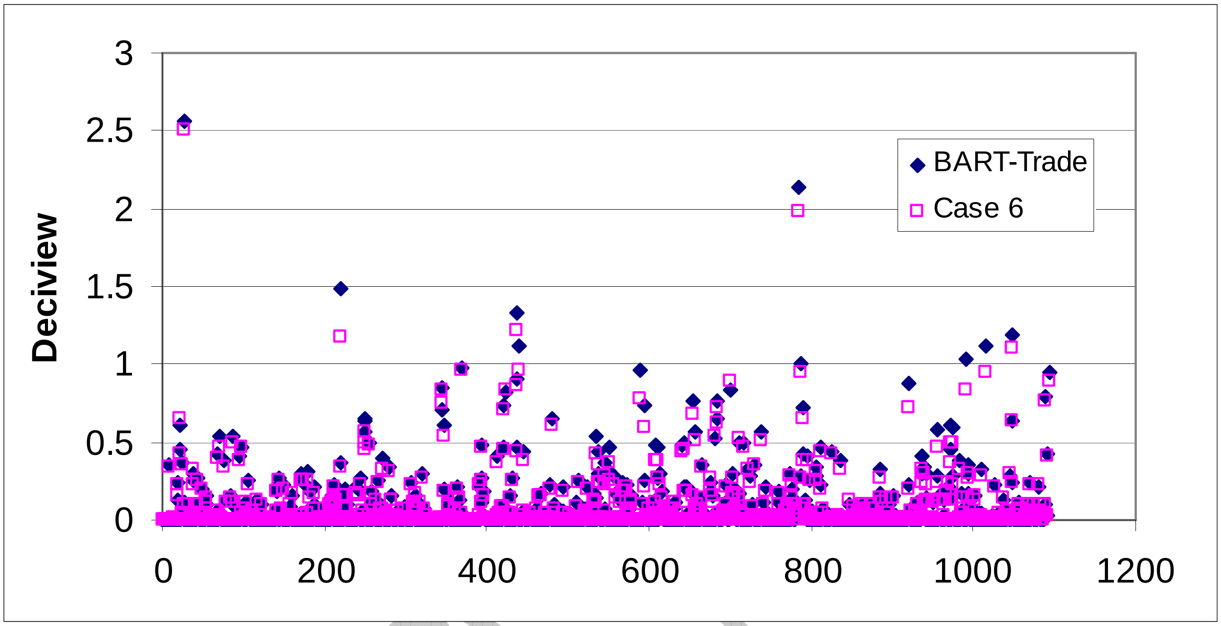
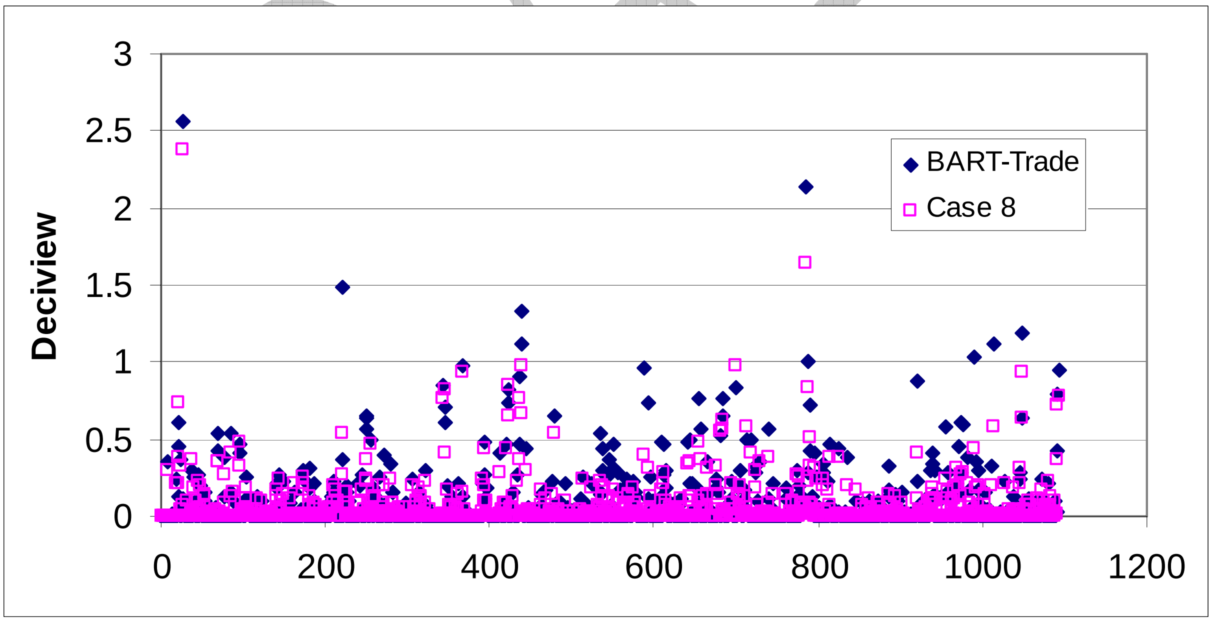


Figure 7.3 Daily Maximum Modeled Impact, 2002 – 2004: BART-Trade vs. Case 8.



Based on these positive results for the 2:1 trading ratio cases, the Department looked at the 20% best and worst days as required under the Wisconsin BART rule for determining visibility equivalency. To define the best and worst days the Department segmented the modeling results for days in which a 0.01 deciview visibility impact is predicted. The model delineated approximately 468 days during 2002 to 2004 based at 0.01 deciview or greater. The Department then segmented these days into the best and worst 94 days of impact (20% x 468 = 94).

The analysis of the best days is relatively straightforward. Table 7.5 shows that the maximum modeled daily impact seen in each year, 2002 to 2004, for the Seney Class I areas increased under case 8 compared to the BART-Trading case by a maximum 0.02 deciview. The other cases show an increase in the maximum daily impact of 0.01 deciview over BART-Trading. These differential visibility impacts are derived by looking at the results on the same day.

Table 7.5 "Best Day" Visibility Impact for 2:1 Trading Ratio Cases – Seney Class I Area.

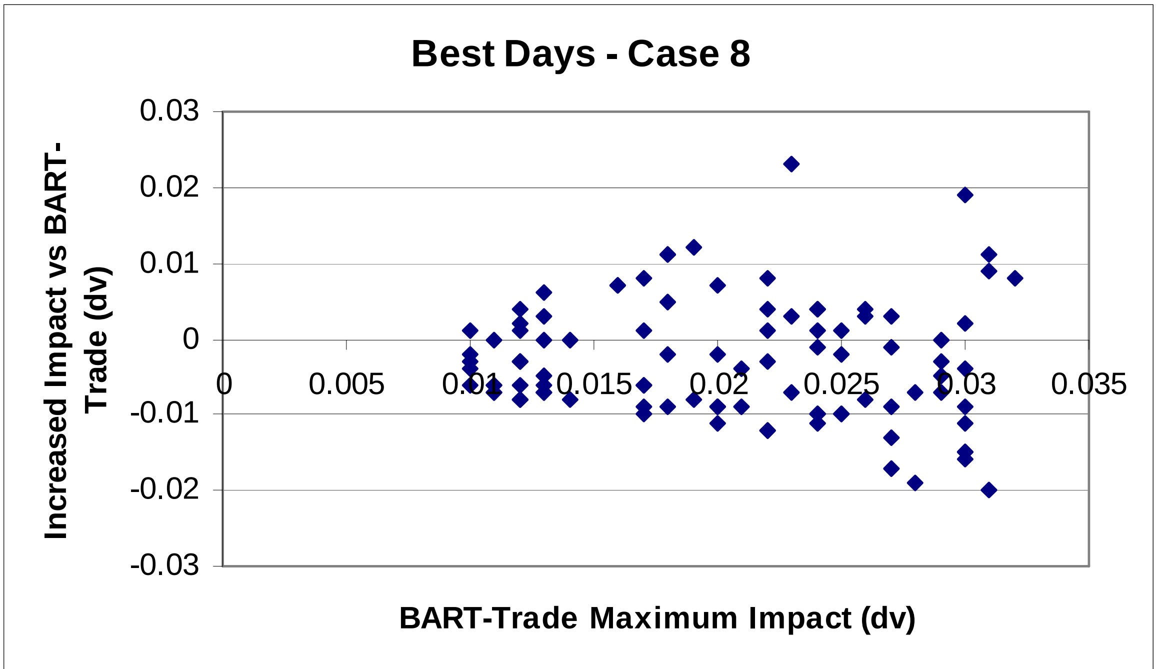
					Difference from BART-Trade Case		
	BART-Trade	Case 5	Case 6	Case 8	Case 5	Case 6	Case 8
Max Impact	0.032	0.042	0.037	0.049	0.01	0.01	0.02
Avg Impact	0.020	0.019	0.019	0.018	(0.00)	(0.00)	(0.00)
Total Impact	1.963	1.788	1.867	1.685	(0.18)	(0.10)	(0.28)

However, when looking at the overall change to visibility, the average of the daily maximum impact slightly decreases. The BART-Trade average value is 0.02 deciview whereas cases 5, 6, and 8 show an average of 0.018 to 0.019. A simple total of the daily impacts show a decrease of 0.1 deciview or more in total. Although these factors are general in nature they indicate that overall the visibility impact has decreased under the 2:1 trading ratio cases.

Still an increase in maximum daily impact is realized under the modeling results. The question is whether the increases are of magnitude and on days that cause a perceptible degradation to visibility. To look at this the issue a plot is made of the change in visibility seen under the trading cases versus the visibility impact for the BART-Trading case for each day. The results for case 8 are presented because this case demonstrated the largest increase in maximum daily impact versus BART-Trading and should show the days with highest overall impacts. The plot, Figure 7.4, shows that there are clearly days where visibility impact increases and days where it decreases under emissions trading. For the days where visibility impact is greatest or approaching 0.032 deciview, the maximum added visibility impact is just less than 0.02 deciview. The total resulting impact is approximately 0.05 deciview. When looking at all the remaining values of the plot the total impacts appear to all be less than the 0.05 deciview.

With values of maximum daily impact remaining at or below the 0.05 deciview level, based on previous regional haze analysis, the Department concludes that the increased impacts to visibility do not create a perceptible change in visibility for the 20% "Best" days at the Seney Class I area. Further, from this analysis there is an overall improvement to the underlying base visibility which will yield more days with perceptibly improved visibility on days with lower visibility impacts. On this basis, the Department concludes that the 2:1 trading ratio ensures visibility equivalency for the 20% "Best Days".

Figure 7.4 Additional Maximum Impact when Trading



Following a similar method, the visibility equivalency is evaluated for the 20% "Worst Days". As shown in Table 7.6, the trading cases all show an improvement in the overall visibility impact when compared to the BART-Trade emission levels. However, values for the maximum daily impact ranging from 2.38 to 2.45 deciview clearly demonstrate that days still occur with significant visibility impact. Therefore the potential for adding visibility impact to an individual day under the trading cases needs to be evaluated further.

Table 7.6 "Worst Day" Visibility Impact for 2:1 Trading Ratio Cases – Seney Class I Area.

					Differential from BART Case		
	BART-Trade	Case 5	Case 6	Case 8	Case 5	Case 6	Case 8
Max Impact	2.56	2.45	2.51	2.38	(0.11)	(0.06)	(0.18)
Avg Impact	0.60	0.49	0.54	0.43	(0.11)	(0.06)	(0.17)
Total Impact	56.23	46.16	50.97	40.15	(10.07)	(5.26)	(16.08)

In looking at what happens to individual days Figures 7.5 through 7.7 show that under each trading case there are more days with decreases (negative values on the y-axis) in impact than increases. The Figures also illustrate that the magnitude of decreases on the individual days are greater than the increases. Under the worst result, Case 8, the increase to visibility impact is less than 0.2 deciview. But, the most significant finding is that when the base visibility impact (x-axis) is greater than 1 deciview the visibility is improved under the trading cases (negative y-axis). In other words, the days that still see the highest visibility impacts under the BART requirements are improved when two SO_2 are traded for a ton of NOx reduction.

Below the 1.0 threshold each case shows days of increased and decreased visibility impact. However in all three cases the magnitude of decreases are greater than the increases in impact. The plots also show that the number of days with decreased impact appear similar or greater than the number of days with increased visibility impact.

Figure 7.5 Additional Maximum Impact – Worst Days – Case 5.

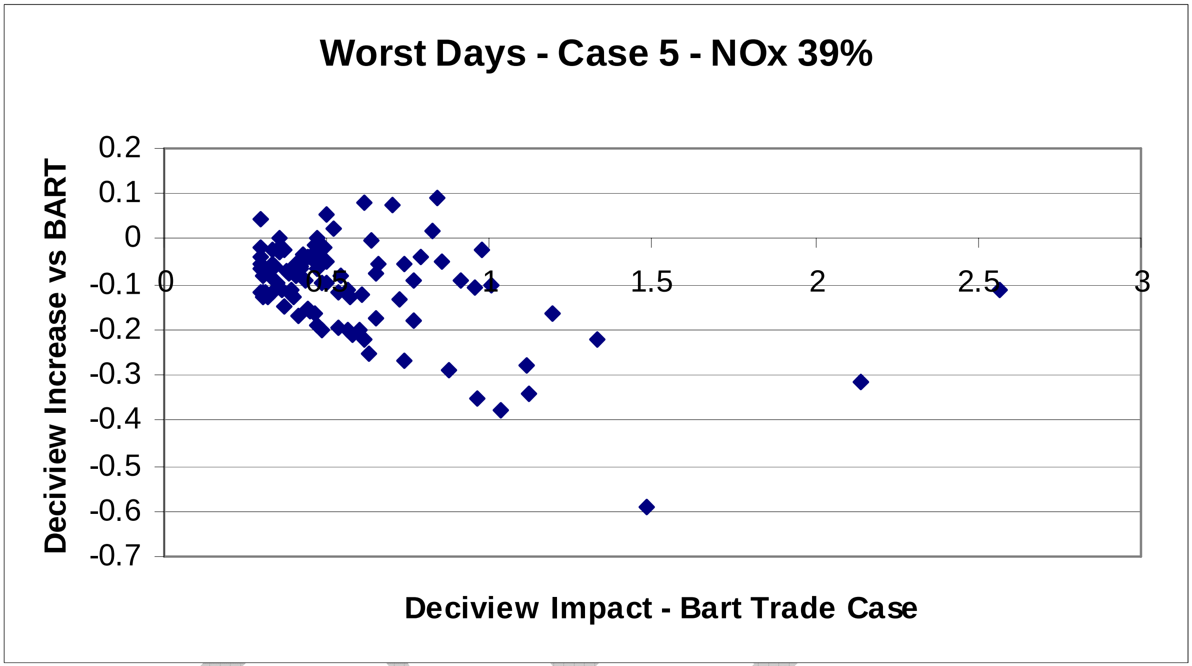


Figure 7.6 Additional Maximum Impact – Worst Days – Case 6.

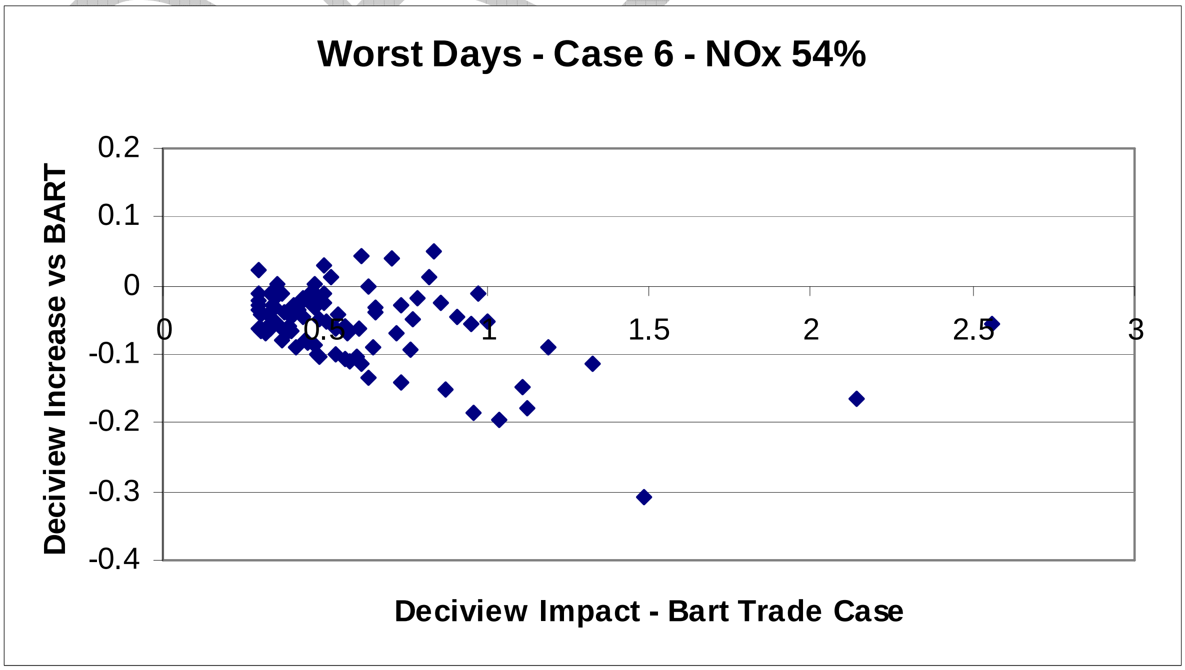
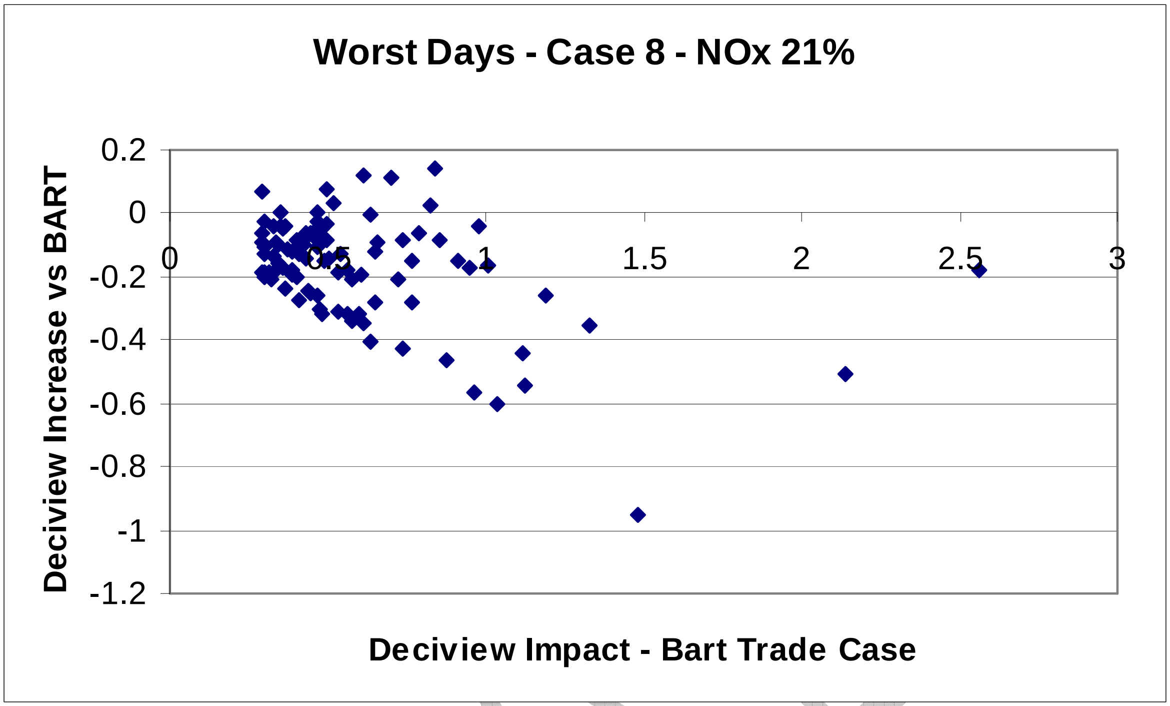


Figure 7.7 Additional Maximum Impact – Worst Days – Case 8



To understand what these increases and decreases mean to visibility equivalency the distribution of days of impact and total deciview impact is counted at different visibility thresholds. The results shown in Table 7.7 confirm that the number of days in the highest impact range is reduced under the trading cases. For this same visibility range the total deciview impact (sum of impact for days > 1.0 deciview) is significantly reduced. On the whole for the trading cases both the number of days and total impact are reduced. It is only when going to the 0.25 to 0.5 deciview range is there an increase in the number of days and at the <0.25 decieview range is there an increase in total impact. This means that all days of impact are shifting to the right in the table to result in an overall lower total impact. Therefore the trading cases are interpreted to be reducing the impact seen during the 20% worst days.

Table 7.7 Number of Days with Modeled Visibility Impact (deciview)

Deciview	> 1.0	1- 0.75	0.75-0.50	0.5-0.25	<0.25	Total
BART-Trade	9	11	22	52	-	94
Case 5	4	11	14	51	14	94
Case 6	5	12	18	55	4	94
Case 8	9	3	13	40	29	94

Table 7.8 Total Visibility Impact (deciview) in Each Visibility Impact Range.

Deciview	> 1.0	1- 0.75	0.75-0.50	0.5-0.25	<0.25	Total
BART-Trade	13	10	13	20	-	56
Case 5	6	9	9	19	3	46
Case 6	8	11	11	21	1	51
Case 8	4	9	8	14	5	40

Since the 20% worst days do not occur simultaneously the last visibility impact that must be considered is the effect of the days of increase on a continuous basis. To do this the difference in total visibility impact between the BART-Trade and trading cases is evaluated for each 30 day rolling period for 2002 to 2004. The plot of these results, figures 7.8 to 7.10, show that there are periods of net increase in visibility impact. However, the maximum increase seen across all of these cases is 0.002 deciview. Theoretically taking 0.002 deciview times 30 days yields an overall increase of 0.06 total deciview during the 30 day period.

The Department concludes that the increase to visibility impact is minimal compared to the improvement to visibility seen under the trading cases. Although individual days may experience additional visibility impact these are relatively small changes in visibility. Further, the trading cases show that larger decreases in visibility impact are close in chronology to the days of increased impact. Therefore, the trading cases are as likely to decrease as increase visibility impact during any short-term period. For these reasons, the Department concludes that a trading ratio of two SO_2 to one NOx results in equivalent visibility improvement.

Figure 7.8

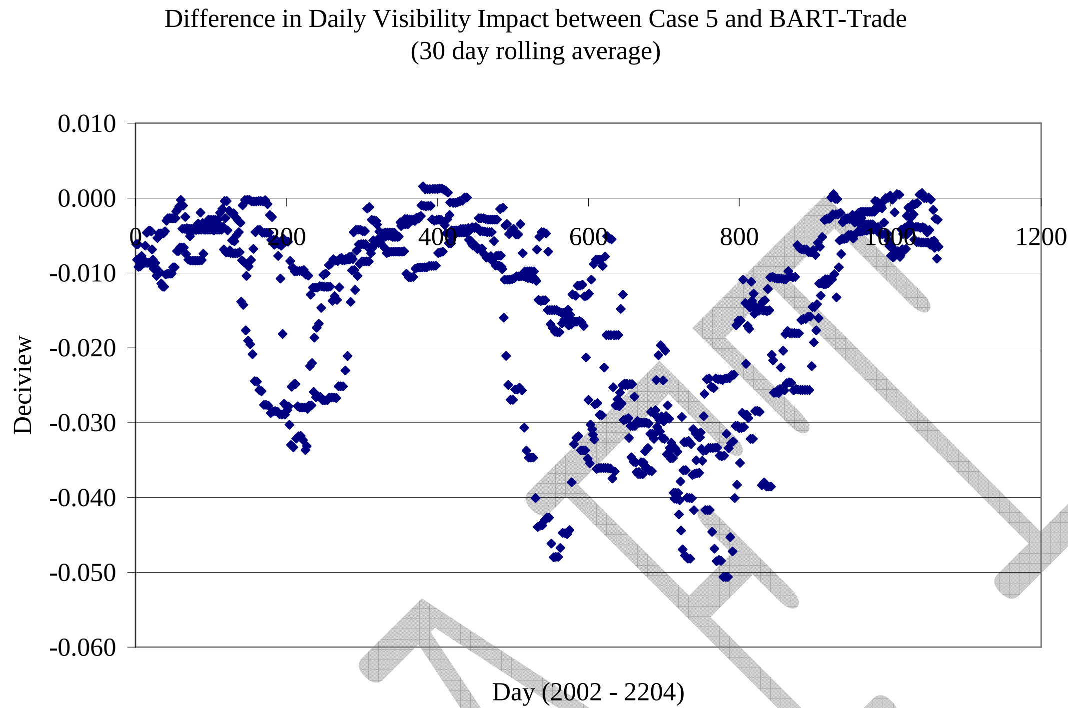


Figure 7.9

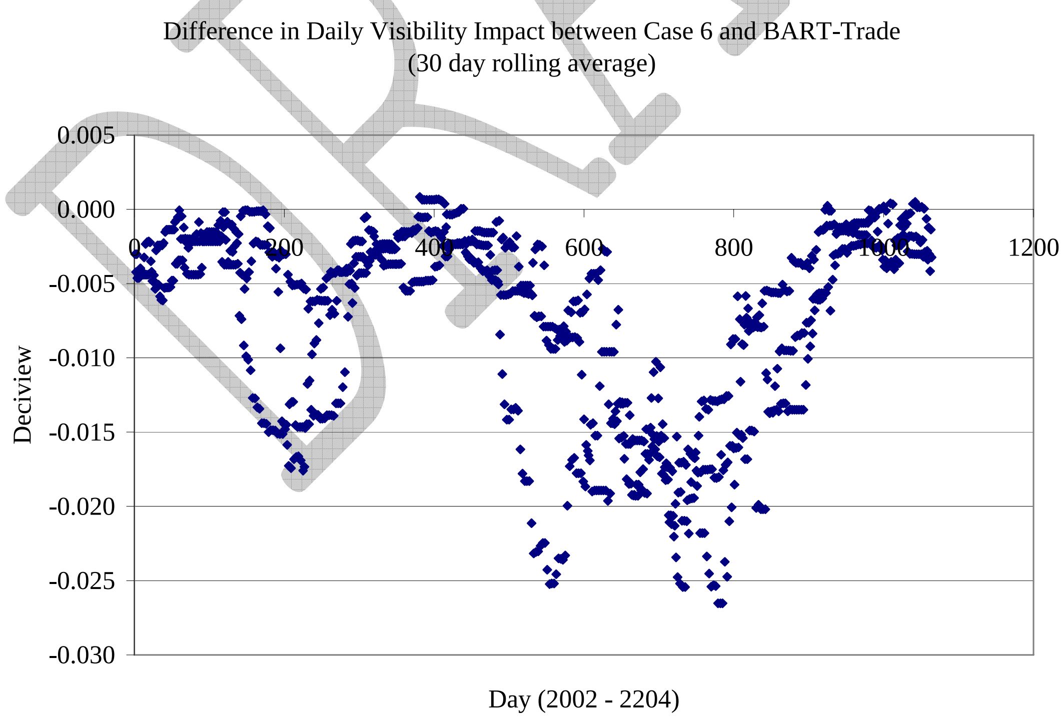
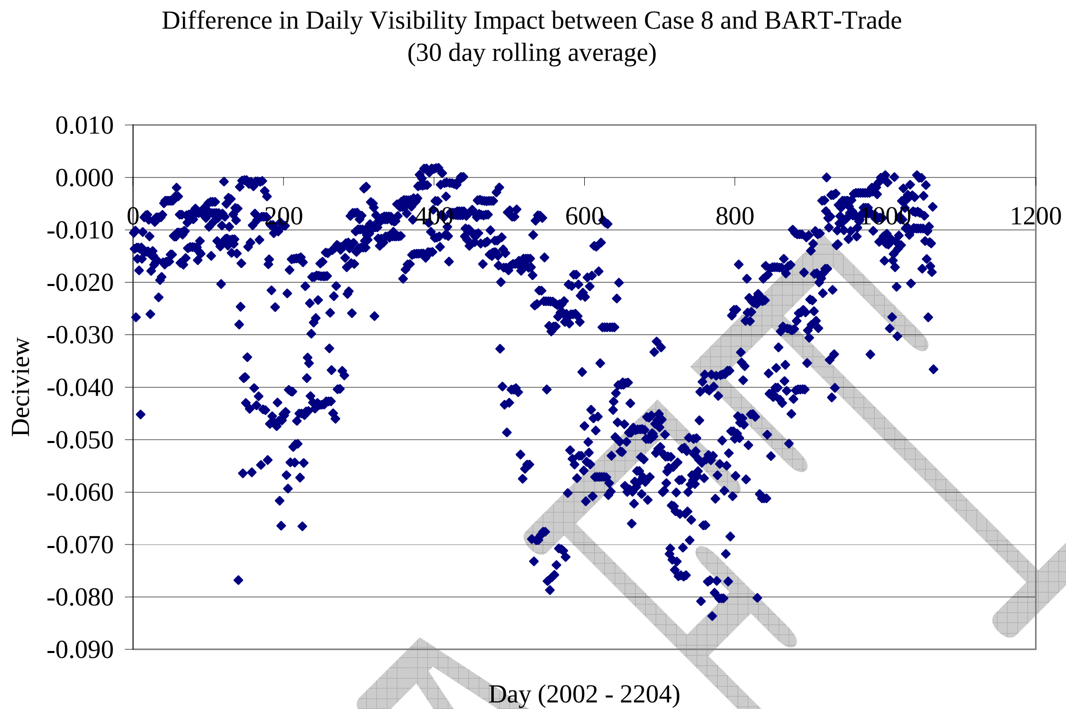


Figure 7.10


Difference in Daily Visibility Impact between Case 8 and BART-Trade
(30 day rolling average)
Deciview
0.010
0.000
-0.010
-0.020
-0.030
-0.040
-0.050
-0.060
-0.070
-0.080
-0.090
0
200
400
600
800
1000
1200
Day (2002 - 2204)

SECTION II - APPENDICES

APPENDIX A

Revisions to
Title V Operating Permit Specific to
BART Requirements

FID 405032870

July, 2011

Refer to file: 405032870-P03 FOP Renewal Draft Permit_Amended July 2011.doc

DRAFT AIR POLLUTION CONTROL OPERATION PERMIT

Note:
Draft revisions particular to Best Available Retrofit Technology (BART) are on pages 9 to 35, and are highlighted in gray. The accompanying draft support documents, "WI BART – Non EGU" and "BART Determination – Amended July 2011, Georgia Pacific Broadway Mill, Green Bay WI" for the proposed BART requirements make up an abbreviated form of the standard preliminary determination (PD) document that is typically used for operating permit renewals. The draft support documents contain a justification for the proposed emission control levels of sulfur dioxide, nitrogen oxides, and particulate matter, along with the accompanying modeled visibility impacts for reduction of these three pollutants.

EI FACILITY NO. 405032870 PERMIT NO. 405032870-P03

TYPE: Part 70 Source

Name of Source:	Georgia-Pacific Consumer Products LP
Street Address:	1919 South Broadway Green Bay, Wisconsin 54304
Responsible Official: Title:	Kelly Wolff Operation Manager

is authorized to operate an existing paper manufacturing facility in conformity with the conditions herein, and in compliance with the provisions of Chapter 285, Wis. Stats., and Chapters NR 400 to NR 499, Wis. Adm. Code.

THIS OPERATION PERMIT BECOMES EFFECTIVE ON **Draft** AND EXPIRES **Draft**. A RENEWAL APPLICATION MUST BE SUBMITTED AT LEAST 12 MONTHS, BUT NOT MORE THAN 18 MONTHS, PRIOR TO THIS EXPIRATION DATE [s. NR 407.09(1)(b)1, Wis. Adm. Code].

No permittee may continue operation of a source after the operation permit expires, unless the permittee submits a timely and complete application for renewal of the permit [s. 285.66(3), Wis. Stats., and s. NR 407.04(2), Wis. Adm. Code].

This authorization requires compliance by the permit holder with the emission limitations, monitoring requirements and other terms and conditions set forth in Parts I and II hereof.

Dated at Green Bay, Wisconsin, ____Draft____.

STATE OF WISCONSIN

DEPARTMENT OF NATURAL RESOURCES
For the Secretary

By *Draft*__________________________________

Richard Wulk
Air Management Program
Northeast Region

Preamble

An asterisk "*" throughout this document denotes legal authority, limitations, and conditions which are not federally enforceable.

Georgia-Pacific Consumer Products LP has several existing permits for individual emission units at the facility. The existing permits include Permit No. 87-IRS-098 (issued on January 20, 1988 for Process P10), Permit No. 89-MWH-084 (issued on January 26, 1990 for Processes P11 and P12), Permit No. 89-MWH-143 (issued on May 18, 1990 for Processes P13, P14 and P15), and Permit No. 88-AJH-031B (issued on February 6, 1995 for Boiler B29). Permit No. 88-AJH-031 was originally issued on September 21, 1988, but was later revised as Permit No. 88-AJH-031A on March 29, 1990 and Permit No. 88-AJH-031B on February 6, 1995.

The permittee entered into a consent decree with the United States of America on behalf of USEPA on May 28, 1996 concerning the operation of Boiler 8 (identified as Boiler B28 in this permit). Pursuant to the consent decree, the permittee altered the boiler in a permanent manner such that it would not be capable of operating at a heat input rate greater than 250 mmBTU per hour in any hour of operation while firing coal with a heat content as described in the decree. The fuel feed to the boiler has been restricted by welding stops into the Stephenson Link on the chain type feeder, and by modifying the adjusting rods to limit the height at which the throat blades on the chain type feeder are set, such that Boiler 8 will have a maximum heat input rate no greater than 235 million BTU (mmBTU) per hour while firing coal with the greater of the highest heating value previously fired or expected to be fired in the future.

One condition from the consent decree was modified through a stipulate order dated July 18, 1997. The stipulated order established a maximum heat content in BTUs for the coal burned in Boiler 8. The permittee is required to notify USEPA within one week from the commencement of firing coal with a heat content greater than 13,500 BTUs per pound. The applicable requirements from the consent decree and the stipulated order are incorporated in this permit.

The Title V operation permit includes revisions to Permit Nos. 89-MWH-143, 87-IRS-098 and 88-AJH-031B. New emissions data for paper machines became available during 1996 as a result of studies and tests done by the National Council for Air and Stream Improvements (NCASI). By using the NCASI data, it was determined that the potential volatile organic compound (VOC) emissions from the processes covered by Permit No. 89-MWH-143 had increased from below the Prevention of Significant Deterioration (PSD) significance level (40 tons per year) to above this level. Georgia-Pacific has chosen to have Permit No. 89-MWH-143 revised as a PSD permit through this Title V operation permit.

The revision to Permit No. 87-IRS-098 consists of a new Latest Available Control Techniques and Operating Practices (LACT) determination for the paper machine covered by this permit. LACT is being changed from a maximum VOC emission rate of 5.7 pounds per hour to current operating practices.

The revision to Permit No. 88-AJH-031B is based on a request from the permittee to modify the nitrogen oxide emission limit on Boiler B29. The previous limit was 0.49 pounds of nitrogen oxides per million BTU (mmBTU) of heat input to the boiler. The Title V operation permit incorporates a two tiered nitrogen oxide limit. The nitrogen oxide limit is being increased to 0.60 pounds per million BTU during start-up (steam loads less than 200,000 pounds per hour), but will remain at 0.49 pounds per million BTU during steady state operations (steam loads greater than or equal to 200,000 pounds per hour). This two tiered limit is designed to give Georgia-Pacific some additional flexibility during the start-up phase of the boiler without increasing the potential nitrogen oxide emissions from the boiler.

The permittee is subject to the National Emission Standards for Hazardous Air Pollutants (NESHAPs) outlined in the Maximum Achievable Control Technology (MACT) standards for the Pulp and Paper Industry. There is no pulping of virgin wood fiber or chemical recovery of pulping chemicals at the facility so the standards for chemical recovery operations at pulp and paper mills do not apply to the facility. However, the two chlorine dioxide bleaching processes (P12 and P13) are subject to the MACT standards for bleaching processes. The MACT standard for pulping and bleaching processes was issued as a final rule on November 14, 1997, and published in the Federal Register on April 15, 1998. The permittee will need to notify USEPA that this standard applies to the facility by April 15, 1999 and to demonstrate compliance with the applicable requirements in the MACT standard for pulping and bleaching processes no later than April 15, 2001. The third bleaching process (P31) is not subject to the MACT standards for bleaching because the permittee uses hydrogen peroxide and hypochlorite to bleach secondary fiber in this process and the MACT standard only applies to chlorine dioxide bleaching of secondary fiber.

The permittee is also subject to the National Emission Standards for Hazardous Air Pollutants (NESHAPs) outlined in the Maximum Achievable Control Technology (MACT) standards for the Printing and Publishing Industry. Process P16 represents the flexographic and rotogravure printing presses at the facility. These presses are affected sources under the Printing and Publishing MACT standard so the operation of these presses must comply with the applicable requirements in the MACT standard no later than May 30, 1999.

Active Construction Permits	Expiration Date
92-RV-120	January 25, 2000

Stack and Process Index:

Stack S10, Control C10,
Boiler B23 - 140 mmBTU per hour underfeed stoker boiler - Installed in 1933.
Boiler B24 - 200 mmBTU per hour underfeed stoker boiler - Installed in 1947.
Boiler B25 - 200 mmBTU per hour underfeed stoker boiler - Installed in 1950.
Boiler B26 - 350 mmBTU per hour spreader stoker boiler - Installed in 1962.
Boiler B27 - 615 mmBTU per hour cyclone furnace - Installed in 1969.
Boiler B28 - 235 mmBTU per hour spreader stoker boiler originally rated at 249 mmBTU per hour. The boiler was derated to 235 mmBTU per hour in 1996 - Installed in 1975.
Stack S11, Control C11 & C29,
Boiler B29 - 486 mmBTU per hour fluidized bed boiler - Installed in 1992.

Stack S01,
Process P01 - Paper machine #5 - Installed in 1964.
Stack S02,
Process P02 - Paper machine #6 - Installed in 1965.
Stack S03,
Process P03 - Paper machine #7 - Installed in 1963.
Stack S04,
Process P04 - Paper machine #8 - Installed in 1966.

Stack S05,
Process P05 - Paper machine #9 - Installed in 1971.
<u>Stack and Process Index (continued):</u>
Stack S06, Control C06,
Process P06 - Dry former #1 - Installed in 1977.
Stack S12, Control C12
Process P10 - Dry former #2 - Installed in 1989.
Stack S21,
Process P15 - Paper machine #1 - Installed in 1992.
Stack S32,
Process P32 - Paper machine alpha - Installed in 1980.
Stack S33,
Process P33 - Paper machine #10 - Installed in 1984.
Stack S43,
Process P43 - Paper machine #3 - Installed in 1930.
Stack S44,
Process P44 - Paper machine #4 - Installed in 1936.
Stack S07,
Process P07 - Clean-up solvent usage for paper machines except P15 - Installed pre-1980.

Stack S19, Control C19,
Process P11 - Chlorine dioxide generation - Installed in 1992.
Process P19 - Chlor-alkali process - Installed in 1967.
Stack S20, Control C20,
Process P12 - Chlorine dioxide bleaching - Installed in 1992.
Stack S25, Control C25,
Process P14 - Sodium chlorate generation - Installed in 1992.
Stack S26, Control C13,
Process P13 - Pulping & bleaching for paper machine #1 - Installed in 1992.
Stack S30,
Process P30 - Pulping for all paper machines except #1 - Installed in 1965.
Stack S31,
Process P31 - Bleach plant operations except for P12 and P13 - Installed in 1962.

Stack S16,
Process P16 - Flexographic and rotary printing presses - First unit installed in 1954.
Stack S17,
Process P17 - Letterpress printing operations - First unit installed in 1924.
Stack S18,
Process P18 - Offset printing presses - First unit installed in 1961.

Stack F36,
Process P36 - Wastewater treatment plant - Installed before 1980.
Stack S34, Control C34,
Process P34 - Ash handling for Boiler B29 - Installed in 1992.
Stack S35, Control C35,
Process P35 - Ash handling for Boilers B23 through B28 - Installed in 1984.

Stack F37,

Process P37 - Fugitive dust emissions from unpaved roadways - Installed in 1919.

Stack F38,

Process P38 - Fugitive dust emissions from outdoor storage piles - Installed in 1919.

Permit Shield - Unless precluded by the Administrator of the USEPA, compliance with all emission limitations in this operation permit is considered to be compliance with all emission limitations established under ss. 285.01 to 285.87, Wis. Stats., and emission limitations under the federal clean air act, that are applicable to the source if the permit includes the applicable limitation or if the Department determines that the emission limitations do not apply. The following emission limitations were reviewed in the analysis and preliminary determination and were determined not to apply to this stationary source:

- The New Source Performance Standard (NSPS) for steam generating units in s. NR 440.205, Wis. Adm. Code does not apply to Boilers B23 through B27 because these boilers were installed before the applicability date for this NSPS.
- The New Source Performance Standard (NSPS) for steam generating units in s. NR 440.19, Wis. Adm. Code does not apply to Boiler B28 because this boiler is rated at 235 million BTU per hour of heat input and the NSPS applies to steam generating units of more than 250 million BTU per hour. This boiler was originally rated at 249 mmBTU per hour, but was derated to 235 mmBTU per hour in 1996 to comply with the May 28, 1996 consent decree. According to the Consent Decree, operation of the boiler above 250 mmBTU per hour in any hour of operation will immediately subject it to the applicable requirements of the Standard of Performance for New Stationary Sources, 40 C.F.R. Part 60 (i.e. s. NR 440.19, Wis. Adm. Code).
- The statewide sulfur dioxide limitations in s. NR 417.07, Wis. Adm. Code do not apply to the source because the permittee is subject to the Reasonably Available Control Technology (RACT) sulfur limitations in ch. NR 418, Wis. Adm. Code.
- The biennial compliance emission testing requirement for sulfur dioxide does not apply to the source because the source is not subject to any of the sulfur dioxide emission limitations specified in s. NR 439.075(2)(a)2., Wis. Adm. Code.
- The periodic fuel sampling and analysis requirements in s. NR 439.085, Wis. Adm. Code do not apply to the source because the source is affected by the RACT sulfur limitations in s. NR 418.05, Wis. Adm. Code.
- The Reasonably Available Control Technology (RACT) standard for lithographic printing in s. NR 422.142, Wis. Adm. Code does not apply to Processes P17 and P18 because the facility is not located in one of the nine affected southeastern Wisconsin counties.
- The Reasonably Available Control Technology (RACT) standard for paper coating in s. NR 422.07, Wis. Adm. Code does not apply to the paper machines operated by the permittee based on the definitions for "paper coating" and "web" in s. NR 422.02, Wis. Adm. Code.
- The requirements for control of organic compounds from process lines in s. NR 424.03(2), Wis. Adm. Code do not apply to Processes P01 through P05, P32, P43, P44, P30, P17 and P18 because the emissions from these process lines do not exceed 15 pounds per day (P32, P17 and P18) or they were installed before 1972 (other processes).
- The requirements for control of organic compounds from process lines in ch. NR 424, Wis. Adm. Code do not apply to the waste water treatment plant (Process P36) because the wastewater treatment plant is not considered a process line according to the definition of process line in s. NR 400.02(72), Wis. Adm. Code.
- The Maximum Achievable Control Technology (MACT) standard for pulping and bleaching at pulp and paper mills does not apply to Process P31 because the permittee uses hydrogen peroxide and hypochlorite as bleaching agents while the MACT standard covers only chlorine dioxide bleaching at paper mills that use secondary fiber.

Part I -- The headings for the areas in the permit are defined below. The legal authority for these limitations or methods follows them in [brackets].

Pollutant -- This area will note which pollutant is being regulated by the permit.

Limitations -- This area will list all applicable emission limitations that apply to the source, including case-by-case limitations such as Latest Available Control Techniques (LACT), Best Available Control Technology (BACT), or Lowest Achievable Emission Rate (LAER). It will also list any voluntary restrictions on hours of operation, raw material use, or production rate requested by the permittee to limit potential to emit.

Compliance Demonstration -- The compliance demonstration methods outlined in this area may be used to demonstrate compliance with the associated emission limit or work practice standard listed under the corresponding Limitations area. The compliance demonstration area contains limits on parameters or other mechanisms that will be monitored periodically to ensure compliance with the limitations. The requirement to test as well as initial and periodic test schedules, if testing is required, will be stated here. Not withstanding the compliance determination methods which the owner or operator of a source is authorized to use under ch. NR 439, Wis. Adm. Code, the department may use any relevant information or appropriate method to determine a source's compliance with applicable limitations.

Reference Test Methods, Recordkeeping, and Monitoring Requirements -- Specific EPA Reference test methods or other approved test methods will be contained in this area and are the methods that must be used whenever testing is required. A reference test method will be listed even if no testing is immediately required. Also included in this area are any recordkeeping requirements and their frequency and reporting requirements. Accuracy of monitoring equipment shall meet, at a minimum, the requirements of ss. NR 439.055(3) and (4), Wis. Adm. Code, as specified in Part II of this permit.

Condition Type -- This area specifies other conditions that are applicable to the entire facility that may not be tied to one specific pollutant.

Conditions -- This area lists specific conditions usually applicable to the entire facility or compliance requirements.

Compliance Demonstration -- This area contains monitoring and testing requirements and methods to demonstrate compliance with the conditions.

PART II -- This section contains the general limitations that the permittee must abide by. These requirements are standard for most sources of air pollutants so they are included in this section with every permit.

PART I
SPECIFIC PERMIT CONDITIONS

A. Stack S10; Control C10; Boilers B23, B24, B25 and B26 - These boilers are multiple retort underfeed stoker boilers (B23, B24 and B25) or spreader stoker boilers (B26) that burn coal as a primary fuel, but also burn petroleum coke and mill-derived fuel pellets as alternate fuels. Boiler B23 has a heat input capacity of 140 million BTU per hour and was installed in 1933. Boilers B24 and B25 have heat input capacities of 200 million BTU per hour and were installed in 1947 and 1950 respectively. Boiler B26 has a heat input capacity of 350 million BTU per hour and was installed in 1962.[19]

Note: The limitations in this table apply to each boiler individually unless otherwise indicated. *These boilers have the capacity to fire petroleum coke and mill-derived fuel pellets as alternate fuels. Please see the additional requirements that relate to these alternate operating scenarios for the boilers in Tables E and F of this permit.* ***Note: The requirements and emission limitations outlined in this section apply to the boilers regardless of the fuel being fired.***

POLLUTANT	(a) LIMITATIONS & REQUIREMENTS	(b) COMPLIANCE DEMONSTRATION	(c) REFERENCE TEST METHODS, RECORDKEEPING AND MONITORING REQUIREMENTS
(1) Particulate Matter Emissions *Continued on Next Page …*	1) Emissions may not exceed 0.30 pounds of particulate matter from any stack per million BTU of heat input. [s. NR 415.06(1)(b), Wis. Adm. Code]	1) The permittee shall perform compliance emission testing of particulate matter emissions from Stack S10 to demonstrate compliance with the particulate matter emission limit in A(1)(a)1): a) Testing shall be conducted every 24 months as long as the permit remains valid; b) Each biennial test of particulate matter emissions shall be performed within 90 days of the anniversary date of the issuance of this permit or within 90 days of an alternate date specified by the Department in writing; *Continued on Next Page …*	1) <u>Reference Test Method for Particulate Matter Emissions</u>: Whenever particulate matter emission testing is required by the Department, the permittee shall use U.S. EPA Method 5, including backhalf. [s. NR 439.06(1), Wis. Adm. Code] 2) The permittee shall retain copies of the results of the compliance emission tests specified in condition A(1)(b)1). [s. NR 439.04(1)(a), Wis. Adm. Code] 3) The permittee shall keep records of the type and amount of fuel burned in this boiler on a monthly basis. [s. NR 439.04(1)(d), Wis. Adm. Code]
(1) Particulate Matter Emissions	2) The permittee shall only fire: a) Coal as a primary fuel in this boiler;	c) The permittee may request and the Department may approve a waiver from the required biennial testing provided the results of the most recently	4) The permittee shall record the pressure drop across the baghouse once every eight (8) hours of operation or once per day, whichever yields the greater number of measurements.

[19] The Department recognizes that the emissions from Boilers B23, B24, B25, B26, B27 and B28 discharge through a common stack (S10) and that it would be difficult to determine the emission rate from a specific boiler unless that boiler were the only one of the six boilers operating. The Department also recognizes that all 6 boilers may not be operating at the time of the required compliance emissions tests. If the emissions from Stack S10 meet the most stringent limitations and requirements provided in Tables A, B and C of this Part I, then the emissions from each boiler discharging to this common stack will be deemed to be meeting such limitations and requirements.

POLLUTANT	(a) LIMITATIONS & REQUIREMENTS	(b) COMPLIANCE DEMONSTRATION	(c) REFERENCE TEST METHODS, RECORDKEEPING AND MONITORING REQUIREMENTS
(continued)	b) Petroleum coke and mill-derived fuel pellets as alternate fuels in this boiler. *See Table E for additional requirements that apply while firing petroleum coke in this boiler. See Table F for additional requirements that apply while firing mill-derived fuel pellets in this boiler.* [ss. 285.65(3) and 285.63(1)(a), Wis. Stats.] 3) The permittee shall operate the baghouse (C10) to control particulate matter emissions whenever the boiler is in operation. [s. NR 415.03, Wis. Adm. Code] (a) The permittee shall meet BART requirements for particulate matter emissions no later than December 31, 2011. (b) The permittee shall meet particulate matter emission requirements for BART by meeting the following conditions: (i) Conditions A.1.a.(1), A.1.a.(2) and A.1.a.(3); (ii) Conditions for visible emissions in A.2.a.(1) and A.2.a.(2); (iii) The facility malfunction prevention and abatement plan. [ss. NR 433.05, NR 439.11, Wis. Adm. Code]	completed biennial test demonstrate that particulate matter emissions are 50 percent or less of the applicable limitation in condition A(1)(a)1); d) The testing shall be conducted in accordance with the conditions in DD(4)(a)1). [ss. NR 439.07, 439.075(2)(a), 439.075(3)(b), and 439.075(4)(a)1.b., Wis. Adm. Code] 2) The permittee shall maintain the pressure drop across the baghouse between 3.0 and 12.0 inches of water column. [ss. NR 407.09(4)(a)1., and 439.055(1)(a), Wis. Adm. Code] 3) The permittee shall take appropriate investigative and corrective action in accordance with the procedures in the Malfunction Prevention and Abatement Plan required for this control device whenever the pressure drop is outside of the operating ranges specified in condition A(1)(b)2). [s. NR 407.09(4)(a)1., Wis. Adm. Code] 4) The permittee shall perform periodic internal inspections of the baghouse (C10) to ensure that the control equipment is operating properly. The time interval between inspections may not exceed eighteen (18) months. [s. NR 407.09(4)(a)1., Wis. Adm. Code] 5) The permittee shall prepare and follow a plan for periodic internal inspections of the boiler. This plan shall include the frequency of these inspections and the items to be inspected. [s. NR 407.09(4)(a)1., Wis. Adm. Code]	[s. NR 439.055(2)(b), Wis. Adm. Code] 5) The permittee shall keep records of: a) the date, time, and initials of the person performing the inspections required by condition A(1)(b)4); b) a list of the items inspected; and c) any maintenance or repairs performed as a result of these inspections. [s. NR 439.04(1)(d), Wis. Adm. Code] 6) The permittee shall keep records of: a) the date, time, and initials of the person performing the inspections required by condition A(1)(b)5); b) a list of the items inspected; and c) any maintenance or repairs performed as a result of these inspections. [s. NR 439.04(1)(d), Wis. Adm. Code]
(2) Visible Emissions	1) Opacity may not exceed 20% or number 1 on the Ringlemann chart.	1) The permittee shall calibrate, maintain and operate the continuous emissions monitoring system required	1) <u>Reference Test Method for Visible Emissions</u>: Whenever visible emission testing is required by the Department, the

POLLUTANT	(a) LIMITATIONS & REQUIREMENTS	(b) COMPLIANCE DEMONSTRATION	(c) REFERENCE TEST METHODS, RECORDKEEPING AND MONITORING REQUIREMENTS
	[s. NR 431.04(2), Wis. Adm. Code] 2) The permittee shall calibrate, maintain and operate a continuous monitoring system that meets the performance specifications of condition A(2)(b)1) for the measurement of opacity. [ss. NR 439.095(1)(a), and 439.095(5)(a)1.,Wis. Adm. Code]	by condition A(2)(a)2) in accordance with the performance specifications in Performance Specification 1 in 40 CFR part 60, Appendix B. [s. NR 439.09(1), Wis. Adm. Code] 2) The permittee shall follow a quality control and quality assurance plan as approved by the Department for the continuous monitoring system required by condition A(2)(a)2). [ss. NR 439.09(8), and 439.095(6), Wis. Adm. Code]	permittee shall use U.S. EPA Method 9. [s. NR 439.06(9)(a)1., Wis. Adm. Code] 2) The continuous monitoring system required by condition A(2)(a)2) shall complete one cycle of sampling and analyzing for each successive 10-second period and one cycle of data recording for each successive 6-minute period. [s. NR 439.09(9)(a), Wis. Adm. Code] 3) Unless otherwise specified by the Department, periods of excess visible emissions shall be any 6-minute period during which the average opacity exceeds the limitation in condition A(2)(a)1). [s. NR 439.09(10)(b)1., Wis. Adm. Code] 4) The permittee shall submit quarterly excess emission reports to the Department within 30 days following the end of each calendar quarter. [s. NR 439.09(10), Wis. Adm. Code] 5) The excess emission reports required by condition A(2)(c)4) shall contain the information identified by condition DD(3)(a)1)b). [s. NR 439.09(10)(a), Wis. Adm. Code]
(3) Sulfur Dioxide *Continued on Next Page …*	1) Emissions may not exceed 4.45 pounds of sulfur dioxide per million BTU of heat input when Boiler B29 is operating.[20] [ss. 285.65(3) and 285.63(1)(a), Wis. Stats. & s. NR 404.04(2)(a)2., Wis. Adm. Code]		1) <u>Reference Test Method for Sulfur Dioxide Emissions</u>: Whenever sulfur dioxide emission testing is required by the Department, the permittee shall use U.S. EPA Method 6, 6A, 6B, 6C or 8. [s. NR 439.06(2)(a), Wis. Adm. Code]
(3) Sulfur Dioxide	2) Emissions may not exceed 4.55 pounds of sulfur dioxide per million	1) The permittee shall calibrate, maintain and operate the continuous emissions monitoring system required	2) The continuous monitoring system required by condition A(3)(a)3) shall perform sampling, analyzing, and data

[20] The 4.45 pounds of sulfur dioxide per million BTU of heat input emission limitation comes from Permit No. 88-AJH-031B and is more restrictive than the emission limitation from s. NR 418.05(1)(c)1., Wis. Adm. Code (4.55 pounds per million BTU) which appears in condition A(3)(a)2). The more restrictive limit is necessary to protect the National Ambient Air Quality Standard for sulfur dioxide when Boiler B29 is operating.

POLLUTANT	(a) LIMITATIONS & REQUIREMENTS	(b) COMPLIANCE DEMONSTRATION	(c) REFERENCE TEST METHODS, RECORDKEEPING AND MONITORING REQUIREMENTS
(continued)	BTU of heat input when Boiler B29 is not operating. [s. NR 418.05(1)(c)1., Wis. Adm. Code] 3) The permittee shall calibrate, maintain and operate a continuous monitoring system that meets the performance specifications of condition A(3)(b)(1) for the measurement of sulfur dioxide. [ss. NR 418.05(4)(a), 439.095(1)(a), and 439.095(5)(a)2.b., Wis. Adm. Code] (4) Best Available Retrofit Technology (BART) applies to boiler B26. (a) The permittee shall meet BART requirements for sulfur dioxide emissions no later than December 31, 2015. (b) The permittee shall meet sulfur dioxide emission requirements for BART by meeting one of the following limitations: (i) a sulfur dioxide emission rate limitation of 0.27 pounds per million BTU of heat input to boiler B26 on the basis of a 30-day rolling average; or (ii) total emissions of sulfur dioxide not to exceed 254 tons in any 12-month period and 33 tons in any 30-day period on boiler B26; or (iii) a sulfur dioxide emission rate limitation of 1.01 pounds per million	by condition A(3)(a)3) in accordance with the performance specifications in Performance Specification 2 in 40 CFR part 60, Appendix B. [s. NR 439.09(2), Wis. Adm. Code] 2) The permittee shall follow a quality control and quality assurance plan as approved by the Department for the continuous monitoring system required by condition A(3)(a)3). [s. NR 439.09(8), Wis. Adm. Code] (3) In determining compliance with emission limitations of condition A(3)(a)(4) the permittee shall determine sulfur dioxide emissions using emission data measured according to conditions A(3)(b)(1) and A(3)(b)(2) and according to the following: (a) For condition A(3)(a)(4)(b)(i): (i) In calculating the 30-day rolling average emission rate, in pounds per million BTU, the permittee shall not exclude emissions for any period of time for which flue gas is exiting boiler B26. (ii) The 30-day rolling average emission rate in pounds per million BTU shall be calculated as the average of the hourly emissions, in pounds per million BTU, obtained from the continuous emissions monitoring system over the hours boiler B26 operated during the averaging period. The 30–day rolling period shall consist of the day of monitoring and the previous 29 consecutive calendar days. A new 30–day rolling average emission rate shall be calculated and recorded at the end of each day. (b) For condition A(3)(a)(4)(b)(ii): (i) In calculating the total emissions, in tons per 12-month period and tons per 30-day period, the permittee shall not exclude emissions for any period of time for which flue gas is exiting boiler B26.	recording as follows: a) Complete one cycle of sampling, analyzing, and data recording for each successive 15-minute period. b) The values recorded shall be averaged hourly. c) Hourly averages shall be computed from 4 data points equally spaced over each 1-hour period, except during periods when calibrations, quality assurance or maintenance activities are being performed. During these periods, a valid hour shall consist of at least 2 data points separated by a minimum of 15 minutes. [s. NR 439.09(9)(b), Wis. Adm. Code] 3) Excess emissions for sulfur dioxide are any 24-hour rolling average during which the average sulfur dioxide emissions exceed the emission limitations in conditions A(3)(a)1) and 2). [s. NR 439.09(10)(b)2., Wis. Adm. Code] 4) For purposes of reporting exceedances on the basis of a 24-hour rolling average, any hourly average may be included in only one 24-hour period. An exceedance shall be based on at least 18 and not more than 24 valid recordings of hourly average emission rates in any 24-hour period. [s. NR 439.09(10)(c), Wis. Adm. Code] 5) The permittee shall submit quarterly excess emission reports to the Department within 30 days following the end of each calendar quarter. [s. NR 439.09(10), Wis. Adm. Code] 6) The excess emission reports required by condition A(3)(c)5) shall contain the information identified by condition DD(3)(a)1)b). [s. NR 439.09(10)(a), Wis. Adm. Code] (7) The procedures and methods required for compliance demonstration and for performance testing required by conditions A(3)(b)(3) and A(3)(b)(4) shall be according to the applicable requirements of ch. NR 439. [ss. NR 433.06(1), NR 439 and NR 440, Wis. Adm. Code]

POLLUTANT	(a) LIMITATIONS & REQUIREMENTS	(b) COMPLIANCE DEMONSTRATION	(c) REFERENCE TEST METHODS, RECORDKEEPING AND MONITORING REQUIREMENTS
(3) Sulfur Dioxide (continued)	BTU of heat input to stack S10 on the basis of a 12-month rolling average and 1.53 pounds per million BTU of heat input to stack S10 on the basis of a 30-day rolling average; or (iv) total emissions of sulfur dioxide not to exceed 5,800 tons in any 12-month period and 761 tons in any 30-day period on stack S10; or (v) under the emissions trading program provided under condition A(3a)(b)(5), the permittee shall meet the following emission limitations: (1) the sulfur dioxide emission limitations in condition A(3)(a)(4)(b)(iv), and (2) the sulfur dioxide emission limitations specified in condition A(3a)(a)(1)(b)(v)(2). [s. NR 433.05, Wis. Adm. Code] Note: The sulfur dioxide BART emission limitation on boiler B26 is based on eliminating the firing of coke fuels, combined with continuous operation of a circulating fluidized bed sulfur dioxide scrubber system achieving a minimum 93% sulfur dioxide removal. This technology is noted to establish a basis for determining alternative emission requirements if constraints are encountered in implementing these	(ii) The total emissions, in tons per 12-month period and tons per 30-day period, shall be calculated as the sum of the daily emissions, in tons, obtained from the continuous emissions monitoring system over the days that boiler B26 operated during the compliance period. The 12-month period shall consist of the month of monitoring and the previous 11 consecutive calendar months. A new 12-month total emissions shall be calculated and recorded at the end of each month. The 30−day period shall consist of the day of monitoring and the previous 29 consecutive calendar days. A new 30−day total emissions shall be calculated and recorded at the end of each day. (c) For condition A(3)(a)(4)(b)(iii): (i) In calculating the 12-month rolling average and 30-day rolling average emission rates, in pounds per million BTU, the permittee shall not exclude emissions for any period of time for which flue gas is exiting Stack S10. (ii) The 12-month rolling average and 30-day rolling average emission rates, in pounds per million BTU, shall be calculated as the average of the hourly emissions, in pounds per million BTU, obtained from the continuous emissions monitoring system over the hours that any of the boilers B25, B26, B27 or B28 operated during the averaging period. The 12-month rolling period shall consist of the month of monitoring and the previous 11 consecutive calendar months. A new 12-month rolling average emission limit shall be calculated and recorded at the end of each month. The 30−day rolling period shall consist of the day of monitoring and the previous 29 consecutive calendar days. A new 30−day rolling average emission rate shall be calculated and recorded at the end of each day. (d) For condition A(3)(a)(4)(b)(iv):	(8) In meeting the procedures and methods required for compliance demonstration and for performance testing required by conditions A(3)(b)(3) and A(3)(b)(4), the permittee shall determine the heat input, in million BTU, based on records of the amount of fuel burnt, in tons, and the heat content of the fuel, in million BTU per ton of fuel. [ss. NR 433.05 and NR 433.06, Wis. Adm. Code] (9) In meeting the compliance demonstration required by conditions A(3)(b)(3)(b), A(3)(b)(3)(d) and A(3)(b)(3)(e), the permittee shall perform the following calculations: (a) Tons of emissions shall be calculated daily for use in calculating emissions over each 30-day period. (b) Monthly emissions shall be calculated by adding all daily emissions in that month. These monthly emissions shall be used to calculate emissions over each 12-month period. [ss. NR 433.05 and NR 433.06, Wis. Adm. Code]

POLLUTANT	(a) LIMITATIONS & REQUIREMENTS	(b) COMPLIANCE DEMONSTRATION	(c) REFERENCE TEST METHODS, RECORDKEEPING AND MONITORING REQUIREMENTS
(3) Sulfur Dioxide (continued)	specific technologies which warrant a revision of the individual boiler determined control level as allowed for under s. NR 433.05(5).	(i) In calculating the total emissions, in tons per 12-month period and tons per 30-day period, the permittee shall not exclude emissions for any period of time for which flue gas is exiting Stack S10. (ii) The total emissions, in tons per 12-month period and tons per 30-day period, shall be calculated as the sum of the daily emissions, in tons, obtained from the continuous emissions monitoring system over the days that any of the boilers B25, B26, B27 or B28 operated during the compliance period. The 12-month period shall consist of the month of monitoring and the previous 11 consecutive calendar months. A new 12-month total emissions shall be calculated and recorded at the end of each month. The 30−day compliance period shall consist of the day of monitoring and the previous 29 consecutive calendar days. A new 30−day total emissions shall be calculated and recorded at the end of each day. (e) For condition A(3)(a)(4)(b)(v): (i) In calculating the total emissions, in tons per 12-month period and tons per 30-day period, the permittee shall not exclude emissions for any period of time for which flue gas is exiting Stack S10. (ii) The total emissions, in tons per 12-month period and tons per 30-day period, shall be calculated as the sum of the daily emissions, in tons, obtained from the continuous emissions monitoring system over the days that any of the boilers B25, B26, B27 or B28 operated during the averaging period. The 12-month period shall consist of the month of monitoring and the previous 11 consecutive calendar months. A new 12-month total emissions shall be calculated and recorded at the end of each month. The 30−day period shall consist of the day of monitoring and the previous 29 consecutive calendar days. A new 30−day total emissions shall be calculated and recorded at the end of each day.	

POLLUTANT	(a) LIMITATIONS & REQUIREMENTS	(b) COMPLIANCE DEMONSTRATION	(c) REFERENCE TEST METHODS, RECORDKEEPING AND MONITORING REQUIREMENTS
(3) Sulfur Dioxide (continued)		(4) In demonstrating compliance with emission limitations of condition A(3)(a)(4) the permittee may propose an emissions trading program if the program achieves an improvement in visibility in the mandatory class I federal areas greater than would be achieved through the installation and operation of BART on each boiler subject to BART. The permittee proposing to use an emissions trading program shall submit an emissions trading plan to the department. The plan shall be subject to department and administrator approval and meet the following criteria: (a) The plan shall contain the proposed control strategy and the method of demonstrating compliance; (b) The plan shall achieve either of the following: (i) For each visibility impairing pollutant for which compliance is demonstrated through use of a trading plan, an emission reduction at least 10% greater than would be achieved through the installation and operation of BART on each boiler subject to BART; (ii) An improvement in visibility in the mandatory class I federal areas greater than or equal to the visibility improvement achieved under condition A(3)(b)(4)(b)(i). The improvement in visibility shall be demonstrated by comparing the 20% best days of visibility and the 20% worst days of visibility in at least the 4 mandatory class I federal areas nearest to the source and for each calendar year 2002, 2003 and 2004. The daily visibility shall be determined using an air quality model approved by the EPA for predicting visibility impacts from single emission sources and conducting the air quality modeling	

POLLUTANT	(a) LIMITATIONS & REQUIREMENTS	(b) COMPLIANCE DEMONSTRATION	(c) REFERENCE TEST METHODS, RECORDKEEPING AND MONITORING REQUIREMENTS
(3) Sulfur Dioxide (continued)		analyses according to the guidelines in 40 CFR part 51, Appendix Y, incorporated by reference in s. NR 484.04(11m); (c) Trading shall be between all boilers serving a similar function located on the same property; (d) Boilers participating in the trading shall achieve the required emission reductions on a continuous basis and shall be subject to continuous emission monitoring, which meets the applicable requirements under ch. NR 439; (e) The plan shall specify the monitoring devices and procedures which will be used to provide information sufficient to assess the performance of the proposed emission control measures and to quantify on an hourly average basis the mass flow of each pollutant in pounds per hour and the emission rate of each pollutant in pounds per mmBtu heat input for each boiler participating in the trading. The procedures and methods required for compliance demonstration and for performance testing shall be according to the applicable requirements of ch. NR 439; (f) Excess emission reductions, for the purposes of meeting the BART requirements, shall be emission reductions beyond those required to meet all state and federal requirements and may not include emission reductions used in any other banking or trading program. [ss. NR 433.06(1), NR 439, and NR 484.04, Wis. Adm. Code] (5) If the department approves the emissions trading plan from condition A(3)(b)(4), the department shall propose to revise the source's air quality permit to include the requirements of the emissions trading plan in lieu of the BART requirements for the boilers	

POLLUTANT	(a) LIMITATIONS & REQUIREMENTS	(b) COMPLIANCE DEMONSTRATION	(c) REFERENCE TEST METHODS, RECORDKEEPING AND MONITORING REQUIREMENTS
(3) Sulfur Dioxide (continued)		identified in the emissions trading plan. [s. NR 433.06(2), Wis. Adm. Code] (6) After the department incorporates the emissions trading plan from condition A(3)(b)(4) into the revised air operation permit, the permittee shall comply with the requirements of the emissions trading plan for the boilers identified in the plan. [s. NR 433.06(3), Wis. Adm. Code] (7) The permittee shall notify the Department 90 days prior to selecting a new emission limitation – from the emission limitation options under A(3)(a)(4)(b) – to be complied with. [s. NR 433.05, Wis. Adm. Code]	
3a. Nitrogen Oxides requirements for Boiler B26	(1) Best Available Retrofit Technology (BART) applies to boiler B26. (a) The permittee shall meet BART requirements for nitrogen oxides emissions no later than December 31, 2015. (b) The permittee shall meet nitrogen oxides emission requirements for BART by meeting one of the following limitations: (i) a nitrogen oxides emission rate limitation of 0.22 pounds per million BTU of heat input to boiler B26 on the basis of a 30-day rolling average; or (ii) total nitrogen oxides emissions of 207 tons in any 12-month period and 27 tons in any 30-day period on boiler B26; or	(1) The permittee shall calibrate, maintain and operate a continuous monitoring system for the measurement of nitrogen oxides which meets the performance specifications of condition A(3a)(b)(2) and A(3a)(b)(3). **[s. NR 439.095(5)(a) and (f), Wis. Adm. Code]** (2) The permittee shall calibrate, maintain and operate the continuous emission monitor required by condition A(3a)(b)(1) in accordance with the performance specification 2 in 40 CFR Part 60, Appendix B. **[ss. NR 439.09(2), NR 439.095(6), Wis. Adm. Code]** (3) The continuous emission monitor required by condition A(3a)(b)(1) shall follow a quality control and quality assurance plan, as approved by the Department. **[ss. NR 439.09(8) and NR 439.095(6), Wis. Adm. Code]** (4) In determining compliance with emission limitations of condition A(3a)(a)(1) the permittee shall determine nitrogen oxides emissions using	(1) The procedures and methods required for compliance demonstration and for performance testing required by condition A(3a)(b)(4) and A(3a)(b)(5) shall be according to the applicable requirements of ch. NR 439. [ss. NR 433.06(1), NR 439 and NR 440, Wis. Adm. Code] (2) In meeting the procedures and methods required for compliance demonstration and for performance testing required by conditions A(3a)(b)(4) and A(3a)(b)(5), the permittee shall determine the heat input, in million BTU, based on records of the amount of fuel burnt, in tons, and the heat content of the fuel, in million BTU per ton of fuel. [ss. NR 433.05 and NR 433.06, Wis. Adm. Code] (3) In meeting the compliance demonstration required by conditions A(3a)(b)(3)(b), A(3a)(b)(3)(d) and A(3a)(b)(3)(e), the permittee shall perform the following calculations: (a) Tons of emissions shall be calculated daily for use in calculating emissions over each 30-day period. (b) Monthly emissions shall be calculated by adding all daily emissions in that month. These monthly emissions shall be

POLLUTANT	(a) LIMITATIONS & REQUIREMENTS	(b) COMPLIANCE DEMONSTRATION	(c) REFERENCE TEST METHODS, RECORDKEEPING AND MONITORING REQUIREMENTS
(3a) Nitrogen Oxides (continued)	(iii) nitrogen oxides emission rate limitations of 0.21 pounds per million BTU of heat input to stack S10 on the basis of a 12-month rolling average, and 0.28 pounds per million BTU of heat input to stack S10 on the basis of a 30-day rolling average; or (iv) total nitrogen oxides emissions of 1,200 tons in any 12-month period and 141 tons in any 30-day period on stack S10; or (v) under the emissions trading program provided for under condition A(3a)(b)(5), the permittee shall meet the following emission limitations: (1) total nitrogen oxides emission limitation of 1,080 tons in any 12-month consecutive period and 127 tons in any 30-day consecutive period on stack S10; (2) The emission limitation on nitrogen oxides in condition A(3a)(a)(1)(b)(v)(1) shall be met when: (a) total actual sulfur dioxide emissions do not exceed [5,800 - (N_1*T)] tons for any 12-month consecutive period on stack S10, and (b) total actual sulfur dioxide emissions do not exceed [761 - (N_2*T)] tons sulfur dioxide for any 30-day consecutive period on stack S10, where	emission data measured according to conditions A(3a)(b)(1), A(3a)(b)(2), and A(3a)(b)(3) and according to the following requirements: (a) For condition A(3a)(a)(1)(b)(i): (i) In calculating the 30-day rolling average emission rate, in pounds per million BTU, the permittee shall not exclude emissions for any period of time for which flue gas is exiting boiler B26. (ii) The 30-day rolling average emission rate in pounds per million BTU shall be calculated as the average of the hourly emissions, in pounds per million BTU, obtained from the continuous emissions monitoring system over the hours boiler B26 operated during the averaging period. The 30−day rolling period shall consist of the day of monitoring and the previous 29 consecutive calendar days. A new 30−day rolling average emission rate shall be calculated and recorded at the end of each day. (b) For condition A(3a)(a)(1)(b)(ii): i) In calculating the total emissions, in tons per 12-month period and tons per 30-day period, the permittee shall not exclude emissions for any period of time for which flue gas is exiting boiler B26. (ii) The total emissions, in tons per 12-month period and tons per 30-day period, shall be calculated as the sum of the daily emissions, in tons, obtained from the continuous emissions monitoring system over the days that boiler B26 operated during the compliance period. The 12-month period shall consist of the month of monitoring and the previous 11 consecutive calendar months. A new 12-month total emissions shall be calculated and recorded at the end of each month. The 30−day period shall consist of the day of monitoring and the previous 29 consecutive calendar days. A new 30−day total emissions shall be calculated and recorded at the end of each day.	used to calculate emissions over each 12-month period. [ss. NR 433.05 and NR 433.06, Wis. Adm. Code]

POLLUTANT	(a) LIMITATIONS & REQUIREMENTS	(b) COMPLIANCE DEMONSTRATION	(c) REFERENCE TEST METHODS, RECORDKEEPING AND MONITORING REQUIREMENTS
(3a) Nitrogen Oxides (continued)	N_1 = the difference between (actual total tons nitrogen oxides) and (1,080 tons nitrogen oxides) per consecutive 12-month period on stack S10, N_2 = the difference between (actual total tons nitrogen oxides) and (127 tons nitrogen oxides) per consecutive 30-day period, T = 2.0 = the ratio of (sulfur dioxide tons reduced from 5,800 tons) to (nitrogen oxides tons increased from 1,080 tons) over any consecutive 12-month period, and the ratio of (sulfur dioxide tons reduced from 761 tons) to (nitrogen oxides tons increased from 127 tons) over any consecutive 30-day period. [s. NR 433.05, Wis. Adm. Code] Note: The nitrogen oxides BART emission limitation on boiler B26 is based on continuous operation of over-fire air and flue gas recirculation control designed specifically for NOx control and continuous operation of selective non-catalytic reduction. This technology is noted to establish a basis for determining alternative emission requirements if constraints in implementing these specific technologies are encountered as allowed for under s. NR 433.05(5) warrant a revision of the individual boiler determined control level.	(c) For condition A(3a)(a)(1)(b)(iii): (i) In calculating the 30-day rolling average emission rate, in pounds per million BTU, the permittee shall not exclude emissions for any period of time for which flue gas is exiting Stack S10. (ii) The 30-day rolling average emission rate in pounds per million BTU shall be calculated as the average of the hourly emissions, in pounds per million BTU, obtained from the continuous emissions monitoring system over the hours that any of the boilers B25, B26, B27 or B28 operated during the averaging period. The 30−day rolling period shall consist of the day of monitoring and the previous 29 consecutive calendar days. A new 30−day rolling average emission rate shall be calculated and recorded at the end of each day. (d) For condition A(3a)(a)(1)(b)(iv): (i) In calculating the total emissions, in tons per 12-month period and tons per 30-day period, the permittee shall not exclude emissions for any period of time for which flue gas is exiting Stack S10. (ii) The total emissions, in tons per 12-month period and tons per 30-day period, shall be calculated as the sum of the daily emissions, in tons, obtained from the continuous emissions monitoring system over the days that any of the boilers B25, B26, B27 or B28 operated during the compliance period. The 12-month period shall consist of the month of monitoring and the previous 11 consecutive calendar months. A new 12-month total emissions shall be calculated and recorded at the end of each month. The 30−day compliance period shall consist of the day of monitoring and the previous 29 consecutive calendar days. A new 30−day total emissions shall be calculated and recorded at the end of each day.	

POLLUTANT	(a) LIMITATIONS & REQUIREMENTS	(b) COMPLIANCE DEMONSTRATION	(c) REFERENCE TEST METHODS, RECORDKEEPING AND MONITORING REQUIREMENTS
(3a) Nitrogen Oxides (continued)		(e) For condition A(3a)(a)(1)(b)(v): (i) In calculating the total emissions, in tons per 12-month period and tons per 30-day period, the permittee shall not exclude emissions for any period of time for which flue gas is exiting Stack S10. (ii) The total emissions, in tons per 12-month period and tons per 30-day period, shall be calculated as the sum of the daily emissions, in tons, obtained from the continuous emissions monitoring system over the days that any of the boilers B25, B26, B27 or B28 operated during the averaging period. The 12-month period shall consist of the month of monitoring and the previous 11 consecutive calendar months. A new 12-month total emissions shall be calculated and recorded at the end of each month. The 30−day period shall consist of the day of monitoring and the previous 29 consecutive calendar days. A new 30−day total emissions shall be calculated and recorded at the end of each day. (5) In demonstrating compliance with emission limitations of condition A(3a)(a)(1) the permittee may propose an emissions trading program if the program achieves an improvement in visibility in the mandatory class I federal areas greater than would be achieved through the installation and operation of BART on each boiler subject to BART. The permittee proposing to use an emissions trading program shall submit an emissions trading plan to the department. The plan shall be subject to department and administrator approval and meet the following criteria: (a) The plan shall contain the proposed control strategy and the method of demonstrating compliance; (b) The plan shall achieve either of the following: (i) For each visibility impairing pollutant for which compliance is demonstrated through use of a trading	

POLLUTANT	(a) LIMITATIONS & REQUIREMENTS	(b) COMPLIANCE DEMONSTRATION	(c) REFERENCE TEST METHODS, RECORDKEEPING AND MONITORING REQUIREMENTS
(3a) Nitrogen Oxides (continued)		plan, an emission reduction at least 10% greater than would be achieved through the installation and operation of BART on each boiler subject to BART; (ii) An improvement in visibility in the mandatory class I federal areas greater than or equal to the visibility improvement achieved under condition A(3a)(b)(5)(b)(i). The improvement in visibility shall be demonstrated by comparing the 20% best days of visibility and the 20% worst days of visibility in at least the 4 mandatory class I federal areas nearest to the source and for each calendar year 2002, 2003 and 2004. The daily visibility shall be determined using an air quality model approved by the EPA for predicting visibility impacts from single emission sources and conducting the air quality modeling analyses according to the guidelines in 40 CFR part 51, Appendix Y, incorporated by reference in s. NR 484.04(11m); (c) Trading shall be between all boilers serving a similar function located on the same property; (d) Boilers participating in the trading shall achieve the required emission reductions on a continuous basis and shall be subject to continuous emission monitoring, which meets the applicable requirements under ch. NR 439; (e) The plan shall specify the monitoring devices and procedures which will be used to provide information sufficient to assess the performance of the proposed emission control measures and to quantify on an hourly average basis the mass flow of each pollutant in pounds per hour and the emission rate of each pollutant in pounds per mmBtu heat input for each boiler participating in the trading. The procedures and methods required for compliance demonstration and for performance testing shall be according to the applicable requirements of ch. NR 439; (f) Excess emission reductions, for the purposes of meeting the BART requirements, shall be emission	

POLLUTANT	(a) LIMITATIONS & REQUIREMENTS	(b) COMPLIANCE DEMONSTRATION	(c) REFERENCE TEST METHODS, RECORDKEEPING AND MONITORING REQUIREMENTS
(3a) Nitrogen Oxides (continued)		reductions beyond those required to meet all state and federal requirements and may not include emission reductions used in any other banking or trading program. [ss. NR 433.06(1), NR 439, and NR 484.04, Wis. Adm. Code] (6) If the department approves the emissions trading plan from condition A(3a)(b)(5), the department shall propose to revise the source's air quality permit to include the requirements of the emissions trading plan in lieu of the BART requirements for the boilers identified in the emissions trading plan. [s. NR 433.06(2), Wis. Adm. Code] (7) After the department incorporates the emissions trading plan from condition A(3a)(b)(5) into the revised air operation permit, the permittee shall comply with the requirements of the emissions trading plan for the boilers identified in the plan. [s. NR 433.06(3), Wis. Adm. Code] (8 The permittee shall notify the Department 90 days prior to selecting a new emission limitation – from the emission limitation options under A(3a)(a)(1)(b) – to be complied with. [s. NR 433.05, Wis. Adm. Code]	

B. Stack S10; Control C10; Boiler B27 - This is a cyclone furnace type boiler that burns coal as its primary fuel, natural gas and distillate fuel oil as supplemental fuels, and petroleum coke as an alternate fuel. The boiler has a heat input rating of 615 million BTU per hour and was installed in 1969.[21]

This boiler has the capacity to fire petroleum coke as an alternate fuel. Please see the additional requirements that relate to this alternate operating scenario for the boiler in Table E of this permit. ***Note: The requirements and emission limitations outlined in this section apply to the boiler regardless of the fuel being fired.***

POLLUTANT	(a) LIMITATIONS & REQUIREMENTS	(b) COMPLIANCE DEMONSTRATION	(c) REFERENCE TEST METHODS, RECORDKEEPING AND MONITORING REQUIREMENTS
(1) Particulate Matter Emissions *Continued on Next Page …*	1) Emissions may not exceed 0.30 pounds of particulate matter from any stack per million BTU of heat input. [s. NR 415.06(1)(b), Wis. Adm. Code]	1) The permittee shall perform compliance emission testing of particulate matter emissions from Stack S10 to demonstrate compliance with the particulate matter emission limit in B(1)(a)1: a) Testing shall be conducted every 24 months as long as the permit remains valid; b) Each biennial test of particulate matter emissions shall be performed within 90 days of the anniversary date of the issuance of this permit or within 90 days of an alternate date specified by the Department in writing; c) The permittee may request and the Department may approve a waiver from the required biennial testing provided the results of the most recently completed biennial test demonstrate that particulate matter emissions are 50 percent or less of the applicable limitation in condition B(1)(a)1; d) The testing shall be conducted in accordance with the conditions in DD(4)(a)1. [ss. NR 439.07, 439.075(2)(a), 439.075(3)(b), and 439.075(4)(a)1.b., Wis. Adm. Code]	1) <u>Reference Test Method for Particulate Matter Emissions</u>: Whenever particulate matter emission testing is required by the Department, the permittee shall use U.S. EPA Method 5, including backhalf. [s. NR 439.06(1), Wis. Adm. Code] 2) The permittee shall retain copies of the results of the compliance emission tests specified in condition B(1)(b)1. [s. NR 439.04(1)(a), Wis. Adm. Code] 3) The permittee shall keep records of the type and amount of fuel burned in this boiler on a monthly basis. [s. NR 439.04(1)(d), Wis. Adm. Code]

[21] The Department recognizes that the emissions from Boilers B23, B24, B25, B26, B27 and B28 discharge through a common stack (S10) and that it would be difficult to determine the emission rate from a specific boiler unless that boiler were the only one of the six boilers operating. The Department also recognizes that all 6 boilers may not be operating at the time of the required compliance emissions tests. If the emissions from Stack S10 meet the most stringent limitations and requirements provided in Tables A, B and C of this Part I, then the emissions from each boiler discharging to this common stack will be deemed to be meeting such limitations and requirements.

POLLUTANT	(a) LIMITATIONS & REQUIREMENTS	(b) COMPLIANCE DEMONSTRATION	(c) REFERENCE TEST METHODS, RECORDKEEPING AND MONITORING REQUIREMENTS
(1) Particulate Matter Emissions (continued)	2) The permittee shall only fire: a) Coal as a primary fuel in this boiler; b) Natural gas and distillate fuel oil (#1 and #2) as supplemental fuels in this boiler; and c) Petroleum coke as an alternate fuel in this boiler. *See Table E for additional requirements that apply while firing petroleum coke in the boiler.* [ss. 285.65(3) and 285.63(1)(a), Wis. Stats.] 3) The permittee shall operate the baghouse (C10) to control particulate matter emissions whenever the boiler is in operation. [s. NR 415.03, Wis. Adm. Code] (4) Best Available Retrofit Technology (BART) applies to boiler B27. (a) The permittee shall meet BART requirements for particulate matter emissions no later than December 31, 2011. (b) The permittee shall meet particulate matter emission requirements for BART by meeting the following conditions: (i) Conditions B.1.a.(1), B.1.a.(2) and B.1.a.(3); (ii) Conditions for visible emissions in B.2.a.(1) and B.2.a.(2);	2) The permittee shall maintain the pressure drop across the baghouse between 3.0 and 12.0 inches of water column. [ss. NR 407.09(4)(a)1., and 439.055(1)(a), Wis. Adm. Code] 3) The permittee shall take appropriate investigative and corrective action in accordance with the procedures in the Malfunction Prevention and Abatement Plan required for this control device whenever the pressure drop is outside of the operating range specified in condition B(1)(b)2). [s. NR 407.09(4)(a)1., Wis. Adm. Code] 4) The permittee shall perform periodic internal inspections of the baghouse (C10) to ensure that the control equipment is operating properly. The time interval between inspections may not exceed eighteen (18) months. [s. NR 407.09(4)(a)1., Wis. Adm. Code] 5) The permittee shall prepare and follow a plan for periodic internal inspections of the boiler. This plan shall include the frequency of these inspections and the items to be inspected. [s. NR 407.09(4)(a)1., Wis. Adm. Code]	4) The permittee shall record the pressure drop across the baghouse once every eight (8) hours of operation or once per day, whichever yields the greater number of measurements. [s. NR 439.055(2)(b), Wis. Adm. Code] 5) The permittee shall keep records of: a) the date, time, and initials of the person performing the inspections required by condition B(1)(b)4); b) a list of the items inspected; and c) any maintenance or repairs performed as a result of these inspections. [s. NR 439.04(1)(d), Wis. Adm. Code] 6) The permittee shall keep records of: a) the date, time, and initials of the person performing the inspections required by condition B(1)(b)5); b) a list of the items inspected; and c) any maintenance or repairs performed as a result of these inspections. [s. NR 439.04(1)(d), Wis. Adm. Code]

POLLUTANT	(a) LIMITATIONS & REQUIREMENTS	(b) COMPLIANCE DEMONSTRATION	(c) REFERENCE TEST METHODS, RECORDKEEPING AND MONITORING REQUIREMENTS
	(iii) The facility malfunction prevention and abatement plan. [ss. NR 433.05, NR 439.11, Wis. Adm. Code]		
(2) Visible Emissions	1) Opacity may not exceed 20% or number 1 on the Ringlemann chart. [s. NR 431.04(2), Wis. Adm. Code] 2) The permittee shall calibrate, maintain and operate a continuous monitoring system that meets the performance specifications of condition B(2)(b)1) for the measurement of opacity. [s. NR 439.095(1)(a), Wis. Adm. Code]	1) The permittee shall calibrate, maintain and operate the continuous emissions monitoring system required by condition B(2)(a)2) in accordance with the performance specifications in Performance Specification 1 in 40 CFR part 60, Appendix B. [s. NR 439.09(1), Wis. Adm. Code] 2) The permittee shall follow a quality control and quality assurance plan as approved by the Department for the continuous monitoring system required by condition B(2)(a)2). [ss. NR 439.09(8), and 439.095(6), Wis. Adm. Code]	1) <u>Reference Test Method for Visible Emissions</u>: Whenever visible emission testing is required by the Department, the permittee shall use U.S. EPA Method 9. [s. NR 439.06(9)(a)1., Wis. Adm. Code] 2) The continuous monitoring system required by condition B(2)(a)2 shall complete one cycle of sampling and analyzing for each successive 10-second period and one cycle of data recording for each successive 6-minute period. [s. NR 439.09(9)(a), Wis. Adm. Code] 3) Unless otherwise specified by the Department, periods of excess visible emissions shall be any 6-minute period during which the average opacity exceeds the limitation in condition B(2)(a)1). [s. NR 439.09(10)(b)1., Wis. Adm. Code] 4) The permittee shall submit quarterly excess emission reports to the Department within 30 days following the end of each calendar quarter. [s. NR 439.09(10), Wis. Adm. Code] 5) The excess emission reports required by condition B(2)(c)4) shall contain the information identified by condition DD(3)(a)1)b). [s. NR 439.09(10)(a), Wis. Adm. Code]

POLLUTANT	(a) LIMITATIONS & REQUIREMENTS	(b) COMPLIANCE DEMONSTRATION	(c) REFERENCE TEST METHODS, RECORDKEEPING AND MONITORING REQUIREMENTS
(3) Sulfur Dioxide *Continued on Next Page …*	1) Emissions may not exceed 4.45 pounds of sulfur dioxide per million BTU of heat input when Boiler B29 is operating.[22] [ss. 285.65(3) and 285.63(1)(a), Wis. Stats. & s. NR 404.04(2)(a)2., Wis. Adm. Code]		1) Reference Test Method for Sulfur Dioxide Emissions: Whenever sulfur dioxide emission testing is required by the Department, the permittee shall use U.S. EPA Method 6, 6A, 6B, 6C or 8. [s. NR 439.06(2)(a), Wis. Adm. Code]
(3) Sulfur Dioxide (continued)	2) Emissions may not exceed 4.55 pounds of sulfur dioxide per million BTU of heat input when Boiler B29 is not operating. [s. NR 418.05(1)(c)1., Wis. Adm. Code] 3) The permittee shall calibrate, maintain and operate a continuous monitoring system that meets the performance specifications of condition B(3)(b)1) for the measurement of sulfur dioxide. [ss. NR 418.05(4)(a), 439.095(1)(a), and 439.095(5)(a)2.b., Wis. Adm. Code] (4) Best Available Retrofit Technology (BART) applies to boiler B27. (a) The permittee shall meet BART requirements for sulfur dioxide emissions no later than December 31, 2015.	1) The permittee shall calibrate, maintain and operate the continuous emissions monitoring system required by condition B(3)(a)3) in accordance with the performance specifications in Performance Specification 2 in 40 CFR part 60, Appendix B. [s. NR 439.09(2), Wis. Adm. Code] 2) The permittee shall follow a quality control and quality assurance plan as approved by the Department for the continuous monitoring system required by condition B(3)(a)3). [s. NR 439.09(8), Wis. Adm. Code] (3) In determining compliance with emission limitations of condition B(3)(a)(4) the permittee shall determine sulfur dioxide emissions using emission data measured according to conditions B(3)(b)(1) and B(3)(b)(2) and according to the following: (a) For condition B(3)(a)(4)(b)(i): (i) In calculating the 30-day rolling average emission rate, in pounds per million BTU, the permittee shall	2) The continuous monitoring system required by condition B(3)(a)3) shall perform sampling, analyzing, and data recording as follows: a) Complete one cycle of sampling, analyzing, and data recording for each successive 15-minute period. b) The values recorded shall be averaged hourly. c) Hourly averages shall be computed from 4 data points equally spaced over each 1-hour period, except during periods when calibrations, quality assurance or maintenance activities are being performed. During these periods, a valid hour shall consist of at least 2 data points separated by a minimum of 15 minutes. [s. NR 439.09(9)(b), Wis. Adm. Code] 3) Excess emissions for sulfur dioxide are any 24-hour rolling average during which the average sulfur dioxide emissions exceed the emission limitations in conditions B(3)(a)1) and 2). [s. NR 439.09(10)(b)2., Wis. Adm. Code] 4) For purposes of reporting exceedances on the basis of a 24-hour rolling average, any hourly average may be included in only one 24-hour period. An exceedance shall be based on at

[22] The 4.45 pounds of sulfur dioxide per million BTU of heat input emission limitation comes from Permit No. 88-AJH-031B and is more restrictive than the emission limitation from s. NR 418.05(1)(c)1., Wis. Adm. Code (4.55 pounds per million BTU) which appears in condition B(3)(a)2). The more restrictive limit is necessary to protect the National Ambient Air Quality Standard for sulfur dioxide when Boiler B29 is operating.

POLLUTANT	(a) LIMITATIONS & REQUIREMENTS	(b) COMPLIANCE DEMONSTRATION	(c) REFERENCE TEST METHODS, RECORDKEEPING AND MONITORING REQUIREMENTS
(3) Sulfur Dioxide (continued)	(b) The permittee shall meet sulfur dioxide emission requirements for BART by meeting one of the following limitations: (i) a sulfur dioxide emission rate limitation of 0.23 pounds per million BTU of heat input to boiler B27 on the basis of a 30-day rolling average; or (ii) total sulfur dioxide emissions of 502 tons in any 12-month period and 47 tons in any 30-day period on boiler B27; or (iii) a sulfur dioxide emission rate limitation of 1.01 pounds per million BTU of heat input to stack S10 on the basis of a 12-month rolling average and 1.53 pounds per million BTU of heat input to stack S10 on the basis of a 30-day rolling average; or (iv) total sulfur dioxide emissions of 5,800 tons in any 12-month period and 761 tons in any 30-day period on stack S10; or (v) under the emissions trading program provided under condition B(3a)(b)(5), the permittee shall meet the following emission limitations: (1) the sulfur dioxide emission limitations in condition B(3)(a)(4)(b)(iv), and (2) the sulfur dioxide emission	not exclude emissions for any period of time for which flue gas is exiting boiler B27. (ii) The 30-day rolling average emission rate in pounds per million BTU shall be calculated as the average of the hourly emissions, in pounds per million BTU, obtained from the continuous emissions monitoring system over the hours boiler B27 operated during the averaging period. The 30−day rolling period shall consist of the day of monitoring and the previous 29 consecutive calendar days. A new 30−day rolling average emission rate shall be calculated and recorded at the end of each day. (b) For condition B(3)(a)(4)(b)(ii): (i) In calculating the total emissions, in tons per 12-month period and tons per 30-day period, the permittee shall not exclude emissions for any period of time for which flue gas is exiting boiler B27. (ii) The total emissions, in tons per 12-month period and tons per 30-day period, shall be calculated as the sum of the daily emissions, in tons, obtained from the continuous emissions monitoring system over the days that boiler B27 operated during the compliance period. The 12-month period shall consist of the month of monitoring and the previous 11 consecutive calendar months. A new 12-month total emissions shall be calculated and recorded at the end of each month. The 30−day period shall consist of the day of monitoring and the previous 29 consecutive calendar days. A new 30−day total emissions shall be calculated and recorded at the end of each day. (c) For condition B(3)(a)(4)(b)(iii): (i) In calculating the 12-month rolling average and 30-day rolling average emission rates, in pounds per million BTU, the permittee shall not exclude emissions for any period of time for which flue gas is	least 18 and not more than 24 valid recordings of hourly average emission rates in any 24-hour period. [s. NR 439.09(10)(c), Wis. Adm. Code] 5) The permittee shall submit quarterly excess emission reports to the Department within 30 days following the end of each calendar quarter. [s. NR 439.09(10), Wis. Adm. Code] 6) The excess emission reports required by condition B(3)(c)5) shall contain the information identified by condition DD(3)(a)1)b). [s. NR 439.09(10)(a), Wis. Adm. Code] (7) The procedures and methods required for compliance demonstration and for performance testing required by condition B(3)(b)(3) and B(3)(b)(4) shall be according to the applicable requirements of ch. NR 439. [ss. NR 433.06(1), NR 439 and NR 440, Wis. Adm. Code] (8) In meeting the procedures and methods required for compliance demonstration and for performance testing required by conditions B(3)(b)(3) and B(3)(b)(4), the permittee shall determine the heat input, in million BTU, based on records of the amount of fuel burnt, in tons, and the heat content of the fuel, in million BTU per ton of fuel. [ss. NR 433.05 and NR 433.06, Wis. Adm. Code]

POLLUTANT	(a) LIMITATIONS & REQUIREMENTS	(b) COMPLIANCE DEMONSTRATION	(c) REFERENCE TEST METHODS, RECORDKEEPING AND MONITORING REQUIREMENTS
(3) Sulfur Dioxide (continued)	limitations specified in condition B(3a)(a)(1)(b)(v)(2). [s. NR 433.05, Wis. Adm. Code] Note: The sulfur dioxide BART emission limitation on boiler B27 is based on eliminating the firing of coke fuels, combined with continuous operation of a circulating fluidized bed sulfur dioxide scrubber system achieving a minimum 93% sulfur dioxide removal. This technology is noted to establish a basis for determining alternative emission requirements if constraints are encountered in implementing these specific technologies which warrant a revision of the individual boiler determined control level as allowed for under s. NR 433.05(5).	exiting Stack S10. (ii) The 12-month rolling average and 30-day rolling average emission rates, in pounds per million BTU, shall be calculated as the average of the hourly emissions, in pounds per million BTU, obtained from the continuous emissions monitoring system over the hours that any of the boilers B25, B26, B27 or B28 operated during the averaging period. The 12-month rolling period shall consist of the month of monitoring and the previous 11 consecutive calendar months. A new 12-month rolling average emission limit shall be calculated and recorded at the end of each month. The 30−day rolling period shall consist of the day of monitoring and the previous 29 consecutive calendar days. A new 30−day rolling average emission rate shall be calculated and recorded at the end of each day. (d) For condition B(3)(a)(4)(b)(iv): (i) In calculating the total emissions, in tons per 12-month period and tons per 30-day period, the permittee shall not exclude emissions for any period of time for which flue gas is exiting Stack S10. (ii) The total emissions, in tons per 12-month period and tons per 30-day period, shall be calculated as the sum of the daily emissions, in tons, obtained from the continuous emissions monitoring system over the days that any of the boilers B25, B26, B27 or B28 operated during the compliance period. The 12-month period shall consist of the month of monitoring and the previous 11 consecutive calendar months. A new 12-month total emissions shall be calculated and recorded at the end of each month. The 30−day compliance period shall consist of the day of monitoring and the previous 29 consecutive calendar days. A new 30−day total emissions shall be calculated and recorded at the end of each day.	

POLLUTANT	(a) LIMITATIONS & REQUIREMENTS	(b) COMPLIANCE DEMONSTRATION	(c) REFERENCE TEST METHODS, RECORDKEEPING AND MONITORING REQUIREMENTS
(3) Sulfur Dioxide (continued)		(e) For condition B(3)(a)(4)(b)(v): i) In calculating the total emissions, in tons per 12-month period and tons per 30-day period, the permittee shall not exclude emissions for any period of time for which flue gas is exiting Stack S10. (ii) The total emissions, in tons per 12-month period and tons per 30-day period, shall be calculated as the sum of the daily emissions, in tons, obtained from the continuous emissions monitoring system over the days that any of the boilers B25, B26, B27 or B28 operated during the averaging period. The 12-month period shall consist of the month of monitoring and the previous 11 consecutive calendar months. A new 12-month total emissions shall be calculated and recorded at the end of each month. The 30−day period shall consist of the day of monitoring and the previous 29 consecutive calendar days. A new 30−day total emissions shall be calculated and recorded at the end of each day. (4) In demonstrating compliance with emission limitations of condition B(3)(a)(4) the permittee may propose an emissions trading program if the program achieves an improvement in visibility in the mandatory class I federal areas greater than would be achieved through the installation and operation of BART on each boiler subject to BART. The permittee proposing to use an emissions trading program shall submit an emissions trading plan to the department. The plan shall be subject to department and administrator approval and meet the following criteria: (a) The plan shall contain the proposed control strategy and the method of demonstrating compliance; (b) The plan shall achieve either of the following:	

POLLUTANT	(a) LIMITATIONS & REQUIREMENTS	(b) COMPLIANCE DEMONSTRATION	(c) REFERENCE TEST METHODS, RECORDKEEPING AND MONITORING REQUIREMENTS
(3) Sulfur Dioxide (continued)		(i) For each visibility impairing pollutant for which compliance is demonstrated through use of a trading plan, an emission reduction at least 10% greater than would be achieved through the installation and operation of BART on each boiler subject to BART; (ii) An improvement in visibility in the mandatory class I federal areas greater than or equal to the visibility improvement achieved under condition B(3)(b)(4)(b)(i). The improvement in visibility shall be demonstrated by comparing the 20% best days of visibility and the 20% worst days of visibility in at least the 4 mandatory class I federal areas nearest to the source and for each calendar year 2002, 2003 and 2004. The daily visibility shall be determined using an air quality model approved by the EPA for predicting visibility impacts from single emission sources and conducting the air quality modeling analyses according to the guidelines in 40 CFR part 51, Appendix Y, incorporated by reference in s. NR 484.04(11m); (c) Trading shall be between all boilers serving a similar function located on the same property; (d) Boilers participating in the trading shall achieve the required emission reductions on a continuous basis and shall be subject to continuous emission monitoring, which meets the applicable requirements under ch. NR 439; (e) The plan shall specify the monitoring devices and procedures which will be used to provide information sufficient to assess the performance of the proposed emission control measures and to quantify on an hourly average basis the mass flow of each pollutant in pounds per hour and the emission rate of each pollutant in pounds per mmBtu heat input for each boiler participating in the trading. The procedures and methods required for compliance demonstration and for performance testing shall be according to the	

POLLUTANT	(a) LIMITATIONS & REQUIREMENTS	(b) COMPLIANCE DEMONSTRATION	(c) REFERENCE TEST METHODS, RECORDKEEPING AND MONITORING REQUIREMENTS
(3) Sulfur Dioxide (continued)		applicable requirements of ch. NR 439; (f) Excess emission reductions, for the purposes of meeting the BART requirements, shall be emission reductions beyond those required to meet all state and federal requirements and may not include emission reductions used in any other banking or trading program. [ss. NR 433.06(1), NR 439, and NR 484.04, Wis. Adm. Code] (5) If the department approves the emissions trading plan from condition B(3)(b)(4)(b), the department shall propose to revise the source's air quality permit to include the requirements of the emissions trading plan in lieu of the BART requirements for the boilers identified in the emissions trading plan. [s. NR 433.06(2), Wis. Adm. Code] (6) After the department incorporates the emissions trading plan from condition B(3)(b)(4)(b) into the revised air operation permit, the permittee shall comply with the requirements of the emissions trading plan for the boilers identified in the plan. [s. NR 433.06(3), Wis. Adm. Code] (7) The permittee shall notify the Department 90 days prior to selecting a new emission limitation – from the emission limitation options under B(3)(a)(4)(b) – to be complied with. [s. NR 433.05, Wis. Adm. Code]	
3a. Nitrogen Oxides requirements	(1) Best Available Retrofit Technology (BART) applies to boiler B27. (a) The permittee shall meet BART requirements for nitrogen oxides emissions no later than December 31, 2015.	(1) The permittee shall calibrate, maintain and operate a continuous monitoring system for the measurement of nitrogen oxides which meets the performance specifications of condition B(3a)(b)(2) and B(3a)(b)(3). **[ss. NR 439.095(5)(a) and (f), Wis. Adm. Code]**	(1) The procedures and methods required for compliance demonstration and for performance testing required by condition B(3a)(b)(4) and B(3a)(b)(5) shall be according to the applicable requirements of ch. NR 439. [ss. NR 433.06(1), NR 439 and NR 440, Wis. Adm. Code] (2) In meeting the procedures and methods required for

POLLUTANT	(a) LIMITATIONS & REQUIREMENTS	(b) COMPLIANCE DEMONSTRATION	(c) REFERENCE TEST METHODS, RECORDKEEPING AND MONITORING REQUIREMENTS
(3a) Nitrogen oxides (continued)	(b) The permittee shall meet nitrogen oxides emission requirements for BART by meeting one of the following limitations: (i) a nitrogen oxides emission rate limitation of 0.20 pounds per million BTU of heat input to boiler B27 on the basis of a 30-day rolling average; or (ii) total nitrogen oxides emissions of 437 tons in any 12-month period and 41 tons per 30-day rolling average on boiler B27; or (iii) nitrogen oxides emission rate limitations of 0.21 pounds per million BTU of heat input to stack S10 on the basis of a 12-month rolling average, and 0.28 pounds per million BTU of heat input to stack S10 on the basis of a 30-day rolling average; or (iv) total nitrogen oxides emissions of 1,200 tons in any 12-month period and 141 tons in any 30-day period on stack S10; or (v) under the emissions trading program provided for under condition B(3a)(b)(5), the permittee shall meet the following emission limitations: (1) total nitrogen oxides emission limitation of 1,080 tons in any 12-month period and 127 tons in any 30-	(2) The permittee shall calibrate, maintain and operate the continuous emission monitor required by condition B(3a)(b)(1) in accordance with the performance specification 2 in 40 CFR Part 60, Appendix B. **[ss. NR 439.09(2), NR 439.095(6), Wis. Adm. Code]** (3) The continuous emission monitor required by condition B(3a)(b)(1) shall follow a quality control and quality assurance plan, as approved by the Department. **[ss. NR 439.09(8) and NR 439.095(6), Wis. Adm. Code]** (4) In determining compliance with emission limitations of condition B(3a)(a)(1) the permittee shall determine nitrogen oxides emissions using emission data measured according to conditions B(3a)(b)(1), B(3a)(b)(2), and B(3a)(b)(3) and according to the following requirements: (a) For condition B(3a)(a)(1)(b)(i): (i) In calculating the 30-day rolling average emission rate, in pounds per million BTU, the permittee shall not exclude emissions for any period of time for which flue gas is exiting boiler B27. (ii) The 30-day rolling average emission rate in pounds per million BTU shall be calculated as the average of the hourly emissions, in pounds per million BTU, obtained from the continuous emissions monitoring system over the hours boiler B27 operated during the averaging period. The 30−day rolling period shall consist of the day of monitoring and the previous 29 consecutive calendar days. A new 30−day rolling average emission rate shall be calculated and recorded at the end of each day. (b) For condition B(3a)(a)(1)(b)(ii):	compliance demonstration and for performance testing required by conditions B(3a)(b)(4) and B(3a)(b)(5), the permittee shall determine the heat input, in million BTU, based on records of the amount of fuel burnt, in tons, and the heat content of the fuel, in million BTU per ton of fuel. [ss. NR 433.05 and NR 433.06, Wis. Adm. Code]

POLLUTANT	(a) LIMITATIONS & REQUIREMENTS	(b) COMPLIANCE DEMONSTRATION	(c) REFERENCE TEST METHODS, RECORDKEEPING AND MONITORING REQUIREMENTS
(3a) Nitrogen oxides (continued)	day period on stack S10; (2) The emission limitation on nitrogen oxides in condition B(3a)(a)(1)(b)(v)(1) shall be met when: (a) total actual sulfur dioxide emissions do not exceed [5,800 - (N_1*T)] tons for any consecutive 12-month period on stack S10, and (b) total actual sulfur dioxide emissions do not exceed [761 - (N_2*T)] tons sulfur dioxide for any consecutive 30-day period on stack S10, where N_1 = the difference between (actual total tons nitrogen oxides) and (1,080 tons nitrogen oxides) per consecutive 12-month period on stack S10, N_2 = the difference between (actual total tons nitrogen oxides) and (127 tons nitrogen oxides) per consecutive 30-day period, T = 2.0 = the ratio of (sulfur dioxide tons reduced from 5,800 tons) to (nitrogen oxides tons increased from 1,080 tons) over any consecutive 12-month period, and the ratio of (sulfur dioxide tons reduced from 761 tons) to (nitrogen oxides tons increased from 127 tons) over any consecutive 30-day period. [s. NR 433.05, Wis. Adm. Code]	(i) In calculating the total emissions, in tons per 12-month period and tons per 30-day period, the permittee shall not exclude emissions for any period of time for which flue gas is exiting boiler B27. (ii) The total emissions, in tons per 12-month period and tons per 30-day period, shall be calculated as the sum of the daily emissions, in tons, obtained from the continuous emissions monitoring system over the days that boiler B27 operated during the compliance period. The 12-month period shall consist of the month of monitoring and the previous 11 consecutive calendar months. A new 12-month total emissions shall be calculated and recorded at the end of each month. The 30−day period shall consist of the day of monitoring and the previous 29 consecutive calendar days. A new 30−day total emissions shall be calculated and recorded at the end of each day. (c) For condition B(3a)(a)(1)(b)(iii): (i) In calculating the 30-day rolling average emission rate, in pounds per million BTU, the permittee shall not exclude emissions for any period of time for which flue gas is exiting Stack S10. (ii) The 30-day rolling average emission rate in pounds per million BTU shall be calculated as the average of the hourly emissions, in pounds per million BTU, obtained from the continuous emissions monitoring system over the hours that any of the boilers B25, B26, B27 or B28 operated during the averaging period. The 30−day rolling period shall consist of the day of monitoring and the previous 29 consecutive calendar days. A new 30−day rolling average emission rate shall be calculated and recorded at the end of each day. (d) For condition B(3a)(a)(1)(b)(iv): (i) In calculating the total emissions, in tons per 12-	

POLLUTANT	(a) LIMITATIONS & REQUIREMENTS	(b) COMPLIANCE DEMONSTRATION	(c) REFERENCE TEST METHODS, RECORDKEEPING AND MONITORING REQUIREMENTS
(3a) Nitrogen oxides (continued)	Note: The nitrogen oxides BART emission limitation on boiler B27 is based on continuous operation of over-fire air designed specifically for NOx control and in combination with one or more of the following equipment configurations to achieve additional 60 – 70% control of nitrogen oxides beyond the over-fire air: selective catalytic reduction, selective non-catalytic reduction, and rich reagent injection. This technology is noted to establish a basis for determining alternative emission requirements if constraints in implementing these specific technologies are encountered as allowed for under s. NR 433.05(5) warrant a revision of the individual boiler determined control level.	month period and tons per 30-day period, the permittee shall not exclude emissions for any period of time for which flue gas is exiting Stack S10. (ii) The total emissions, in tons per 12-month period and tons per 30-day period, shall be calculated as the sum of the daily emissions, in tons, obtained from the continuous emissions monitoring system over the days that any of the boilers B25, B26, B27 or B28 operated during the compliance period. The 12-month period shall consist of the month of monitoring and the previous 11 consecutive calendar months. A new 12-month total emissions shall be calculated and recorded at the end of each month. The 30−day compliance period shall consist of the day of monitoring and the previous 29 consecutive calendar days. A new 30−day total emissions shall be calculated and recorded at the end of each day. (e) For condition B(3a)(a)(1)(b)(v): (i) In calculating the total emissions, in tons per 12-month period and tons per 30-day period, the permittee shall not exclude emissions for any period of time for which flue gas is exiting Stack S10. (ii) The total emissions, in tons per 12-month period and tons per 30-day period, shall be calculated as the sum of the daily emissions, in tons, obtained from the continuous emissions monitoring system over the days that any of the boilers B25, B26, B27 or B28 operated during the averaging period. The 12-month period shall consist of the month of monitoring and the previous 11 consecutive calendar months. A new 12-month total emissions shall be calculated and recorded at the end of each month. The 30−day period shall consist of the day of monitoring and the previous 29 consecutive calendar days. A new 30−day total emissions shall be calculated and recorded at the end of each day.	

POLLUTANT	(a) LIMITATIONS & REQUIREMENTS	(b) COMPLIANCE DEMONSTRATION	(c) REFERENCE TEST METHODS, RECORDKEEPING AND MONITORING REQUIREMENTS
(3a) Nitrogen oxides (continued)		(5) In demonstrating compliance with emission limitations of condition B(3a)(a)(1) the permittee may propose an emissions trading program if the program achieves an improvement in visibility in the mandatory class I federal areas greater than would be achieved through the installation and operation of BART on each boiler subject to BART. The permittee proposing to use an emissions trading program shall submit an emissions trading plan to the department. The plan shall be subject to department and administrator approval and meet the following criteria: (a) The plan shall contain the proposed control strategy and the method of demonstrating compliance; (b) The plan shall achieve either of the following: (i) For each visibility impairing pollutant for which compliance is demonstrated through use of a trading plan, an emission reduction at least 10% greater than would be achieved through the installation and operation of BART on each boiler subject to BART; (ii) An improvement in visibility in the mandatory class I federal areas greater than or equal to the visibility improvement achieved under condition B(3a)(b)(5)(b)(i). The improvement in visibility shall be demonstrated by comparing the 20% best days of visibility and the 20% worst days of visibility in at least the 4 mandatory class I federal areas nearest to the source and for each calendar year 2002, 2003 and 2004. The daily visibility shall be determined using an air quality model approved by the EPA for predicting visibility impacts from single emission sources and conducting the air quality modeling analyses according to the guidelines in 40 CFR part 51, Appendix Y, incorporated by reference in s. NR 484.04(11m);	

POLLUTANT	(a) LIMITATIONS & REQUIREMENTS	(b) COMPLIANCE DEMONSTRATION	(c) REFERENCE TEST METHODS, RECORDKEEPING AND MONITORING REQUIREMENTS
(3a) Nitrogen oxides (continued)		(c) Trading shall be between all boilers serving a similar function located on the same property; (d) Boilers participating in the trading shall achieve the required emission reductions on a continuous basis and shall be subject to continuous emission monitoring, which meets the applicable requirements under ch. NR 439; (e) The plan shall specify the monitoring devices and procedures which will be used to provide information sufficient to assess the performance of the proposed emission control measures and to quantify on an hourly average basis the mass flow of each pollutant in pounds per hour and the emission rate of each pollutant in pounds per mmBtu heat input for each boiler participating in the trading. The procedures and methods required for compliance demonstration and for performance testing shall be according to the applicable requirements of ch. NR 439; (f) Excess emission reductions, for the purposes of meeting the BART requirements, shall be emission reductions beyond those required to meet all state and federal requirements and may not include emission reductions used in any other banking or trading program. [ss. NR 433.06(1), NR 439, and NR 484.04, Wis. Adm. Code] (6) If the department approves the emissions trading plan from condition B(3a)(b)(5), the department shall propose to revise the source's air quality permit to include the requirements of the emissions trading plan in lieu of the BART requirements for the boilers identified in the emissions trading plan. [s. NR 433.06(2), Wis. Adm. Code] (7) After the department incorporates the emissions trading plan from condition B(3a)(b)(5) into the	

POLLUTANT	(a) LIMITATIONS & REQUIREMENTS	(b) COMPLIANCE DEMONSTRATION	(c) REFERENCE TEST METHODS, RECORDKEEPING AND MONITORING REQUIREMENTS
		revised air operation permit, the permittee shall comply with the requirements of the emissions trading plan for the boilers identified in the plan. [s. NR 433.06(3), Wis. Adm. Code] (7) The permittee shall notify the Department 90 days prior to selecting a new emission limitation – from the emission limitation options under B(3a)(a)(1)(b) – to be complied with. [s. NR 433.05, Wis. Adm. Code]	

APPENDIX B

Control Equipment Costing Sheets
for
Georgia Pacific BART Boilers
SO2 and NOx

WDNR – July 2011

Summary of SO_2 Control Cost Estimates for Georgia Pacific Boilers B26 and B27 Combined Flue

	Dry FGD	Wet FGD	
Parameter	**B26/27 93% control** [a,b]	**B26/27 95% control** [b]	**B26/27 98% control** [b]
Boiler Size (MW)	76.3	76.3	76.3
Baseline Emissions (tpy)	10,875	10,875	10,875
Maximum Reduction (%)	93	95	98
Fraction Reduced	0.93	0.95	0.98
Emissions Reduction (tpy)	10,114	10,331	10,658
Total Installed Cost	**38,250,000**	**55,869,465**	**55,869,465**
Operating labor	131,400	43,800	43,800
Supervisor Labor	19,710	6,570	6,570
Maintenance labor & equipment	2,748,242	87,600	87,600
Electricity- direct	404,976	705,846	705,846
Electricity- fan make-up	201,680	---	---
Sorbent	4,182,080	18,833,008	19,427,735
Process water	2,832	348,016	359,006
Landfill Scrubber system solids	860,289	1,256,030	1,295,694
Additional Process Steam	---	2,429,442	2,506,162
Overhead rate	1,739,611	82,782	82,782
Taxes, insurance, admin. Factor	809,671	2,234,779	2,234,779
Capital recovery factor	2,222,547	6,134,467	6,134,467
Total Annual Operating Cost ($)	**16,020,671**	**32,162,340**	**32,884,440**
Effectiveness, ($/ton)	**1,584**	**3,113**	**3,086**

[a] Total Installed Cost for Turbosorb based on Babcock Power quote received by GP in 2010[1]. The cost included B28, making the cost estimate conservative for the B26/B27 combined flue alone.

[b] Dry FGD operating cost and wet FGD capital/operating costs are estimated from the BART analysis submitted by GP[2].

NOx

Boiler B27 - Overfire Air

Boiler Capacity	50	MW	Tons/Year	grams/sec
Emissions			2,729	103
Existing Control Efficiency	0%			
Control Efficiency	50%	OFA		
Controlled Emissions			1,365	52
Emitted			1,365	52
Visibility Improvement - Seney	0.005	dv per gr/sec	0.25	deciview

OFA Cost:

				Reference
Total Direct Cost (TDC)			693,980	4
OFA Equipment		570,000		
Instrumentation		24,812		2
Electrical		99,168		2
Indirect Cost (IC)	% of TDC		536,565	
Construction Cost		412,585		2
Owners Cost	3%	20,819		3
Total Installed Cost (TIC)			1,230,545	
Annual Operating Cost			187,161	
Maintenance labor & Parts:	1.50%	18,458		3
Electricity:		52,539		2
Overhead Rate:	0			3
Taxes and Insurance:	0			3
Capital Recovery:	9.44%	116,163		2
Total Annualized Cost			**187,161**	

OFA Control Cost

S/ton =	**137**
$/dv =	**0.74**

NOx

Boiler B27 - Regenerative SCR

Boiler Capacity	50	MW	Tons/Year	grams/sec
Emissions			2,729	103
Existing Control Efficiency	0%			
Control Efficiency	70%	RSCR		
Controlled Emissions			1,910	72
Emitted			819	31
Visibility Improvement - Seney	0.005	dv per gr/sec	0.35	deciview

RSCR Cost:

				Reference
Total Direct Cost (TDC)			6,100,000	1
RSCR:				
Indirect Cost (IC)	% of TDC		2,013,000	
Installation:	30%	1,830,000		1
Owners Cost:	3%	183,000		2
Total Installed Cost (TIC)			8,113,000	
Annual Operating Cost			3,519,674	
Additional Operating & Supervisory Labor:		-		*3*
Maintenance labor & Parts:	1.50%	121,695		*3*
Electricity:	see worksheet	365,574		1
Ammonia Consumption:	5.81 tons/ ton NOx	1,775,815		*6*
Ammonia Inventory:	12000 gal tank	7,186		1
Natural Gas:	2.5 mmbtu/hr	146,292		`
Catalyst:	3 year	337,245		1
Overhead Rate:		-		*3*
Taxes and Insurance:		-		*3*
Capital Recovery:	9.44%	765,867		2
Total Annualized Cost			**3,519,674**	

RSCR Control Cost

S/ton =	**1,842**
$/dv =	**10**

RSCR Electricity Worksheet

Enduse	Capacity		kW
booster fan	891	bhp	664
comb air fan	30	bhp	22
hydraulic power unit	8	bhp	6
ammonia pumps	0.5	bhp	0
instrument comp	15	bhp	11
misc instruments	2	kw	2
Hydraulic heaters, est.	1	kw	1
		Total kW	707

Annual Consumption	8760	hours / year	6,196,168
Annual Cost	0.059	cents / kWh	365,574

Boiler B27 - OverFire Air + Regenerative SCR

Boiler Capacity	50	MW	Tons/Year	grams/sec
Emissions			2,729	103
			Total Controlled Emissions	
Existing Control Efficiency	0%			
Control Efficiency	50%	OFA	1,365	52
Control Efficiency	70%	RSCR	955	36
Total Control Efficiency	85%	OFA + RSCR	2,320	88
Emitted			409	15
Visibility Improvement - Seney	0.005	dv per gr/sec	0.43	deciview

OFA Cost:

OFA Annualized Cost	187,161

RSCR Cost:

					Reference
Total Direct Cost (TDC)				6,100,000	
	RSCR		6,100,000		1
Indirect Cost (IC)		% of TDC		2,013,000	
	Installation:	30%	1,830,000		
	Owners Cost:	3%	183,000		2
Total Installed Cost (TIC)				8,113,000	
Annual Operating Cost				2,631,767	
	Additional Operating & Supervisory Labor:		-		*3*
	Maintenance labor & Parts:	1.50%	121,695		*3*
	Electricity:	see worksheet	365,574		1
	Ammonia Consumption:	5.81 tons/ ton NOx	887,907		
	Ammonia Inventory:	12000 gal tank	7,186		1
	Natural Gas:	2.5 mmbtu/hr	146,292		1
	Catalyst:	3 year	337,245		2
	Overhead Rate:		-		*3*
	Taxes and Insurance:		-		*3*
	Capital Recovery:	9.44%	765,867		2
Total Annualized Cost				**2,631,767**	

OFA + RSCR Control Cost

Total Annualized Cost =	**2,818,927**
S/ton =	**1,215**
$/dv =	**6.6**

Boiler B27 - OverFire Air + Rich Reagent Injection + Selective non-Catalytic Reduction

Boiler Capacity	50	MW		Tons/Year	grams/sec
Emissions				2,729	103
				Total Controlled Emissions	
Existing Control Efficiency	0%				
Control Efficiency	60%	OFA		1,637	62
Control Efficiency	60%	RRI/SNCR		655	25
Total Control Efficiency	84%	OFA + RSCR		2,292	87
Emitted				437	17
Visibility Improvement - Seney	0.005	dv per gr/sec		0.42	deciview

OFA Cost:

OFA Annualized Cost	187,161

RRI/SNCR Cost:

						Reference
Total Direct Cost (TDC)					1,935,579	
	RRI/SNCR			1,190,365		4
	Concrete			69,918		2
	Piping & Insulation			443,204		2
	Electrical			232,092		2
Indirect Cost (IC)			% of TDC		387,116	
		General Facilities	5%	96,778.97		3
		Engineering & Home Office	10%	193,557.95		3
		Process Contingency	5%	96,778.97		3
Total Installed Cost (TIC)					2,322,695	
Project Contingency			15% of TIC		348,404	3
Total Plant Cost (TPC)					2,671,100	
Preproduction Cost			2 % of TPC		53,422	
Inventory	42000 gal		1.35 $/gal		56,700	4 / 2
Total Capital Cost					2,781,222	
Annual Operating Cost					1,685,633	
		urea	88+33 gal/hr (CAA rates)	1,372,140		4
		water	double GP 473	946		2
		Electricity		50,000		2
		Overhead Rate:	0			3
		Taxes and Insurance:	0			3
		Capital Recovery:	9.44% of TCC	262,547		2
Total Annualized Cost					**1,685,633**	

OFA + RRI/SNCR Control Cost

Total Annualized Cost =	**1,872,794**
S/ton =	**817**
$/dv =	**4.4**

Boiler B27 - OverFire Air + Selective non-Catalytic Reduction + InDuct SCR

Boiler Capacity	50	MW	Tons/Year	grams/sec
Emissions			2,729	103
			Total Controlled Emissions	
Existing Control Efficiency	0%			
Control Efficiency 1	55%	OFA	1,501	57
Control Efficiency 2	40%	SNCR	491	19
Control Efficiency 3	45%	InDuct SCR	332	13
Total Control Efficiency	85%	OFA + RSCR	2,324	88
Emitted			405	15
Visibility Improvement - Seney	0.005	dv per gr/sec	0.43	deciview

OFA Cost:

OFA Annualized Cost	187,161

SNCR / InDuct SCR

						Reference
Total Plant Cost (TCC)					-	
SNCR / InDuct Total System	188 $/kw				9,450,000	5
Preproduction Cost		2 % of TPC			189,000	3
Inventory	42000 gal	1.35 $/gal			56,700	4 / 2
Total Capital Cost					9,695,700	
Annual Operating Cost					2,055,636	
urea	33 gal/hr (double SNCR rate CAA rat			855,360		4
water	double GP 473			946		2
Electricity				50,000		2
Catalyst	1/2 RSCR			234,056		2
Overhead Rate:			0			3
Taxes and Insurance:			0			3
Capital Recovery:	9.44% of TCC			915,274		2
Total Annualized Cost					**2,055,636**	

OFA + RRI/SNCR Control Cost

Total Annualized Cost =	**2,242,797**
S/ton =	**965**
$/dv =	**5.2**

NOx

Boiler B26 - Overfire Air / Flue Gas Recirculation

Boiler Capacity	25	MW	Tons/Year	grams/sec
Emissions			640	27
Existing Control Efficiency	0%			
Control Efficiency	35%	OFA		
Controlled Emissions			224	9
Emitted			416	17
Visibility Improvement - Seney	0.005	dv per gr/sec	0.05	deciview

Note: Boiler B26 uncontrolled emission rate = 0.68 lbs/mmbtu

OFA / FGR Cost:

					Reference
Total Direct Cost (TDC)				1,294,486	
	OFA Equipment		1,232,000		4
	Instrumentation		17,270		2
	Electrical		45,216		2
Indirect Cost (IC)		% of TDC		442,890	
	Construction Cost		404,055		2
	Owners Cost	3%	38,835		3
Total Installed Cost (TIC)				1,737,376	
Annual Operating Cost				244,797	
	Maintenance labor & Parts:	1.50%	26,061		3
	Electricity:		54,728		2
	Overhead Rate:	0			3
	Taxes and Insurance:	0			3
	Capital Recovery:	9.44%	164,008		2
Total Annualized Cost				**244,797**	

OFA / FGR Control Cost

S/ton =	**1,093**
$/dv =	**5.34**

NOx

Boiler B26 - Selective non-Catalytic Reduction

Boiler Capacity	25	MW	Tons/Year	grams/sec
Emissions			640	27
Existing Control Efficiency	0%			
Control Efficiency	50%	SNCR		
Controlled Emissions			320	13
Emitted			320	13
Visibility Improvement - Seney	0.005	dv per gr/sec	0.07	deciview

Note: Boiler B26 uncontrolled emission rate = 0.68 lbs/mmbtu

					Reference
Total Direct Cost (TDC)				1,897,155	
SNCR			1,217,000		4
Concrete			68,917		2
Piping & Insulation			398,190		2
Electrical			213,048		2
Indirect Cost (IC)		% of TDC		379,431	
General Facilities		5%	94,857.75		3
Engineering & Home Office		10%	189,715.50		3
Process Contingency		5%	94,857.75		3
Total Installed Cost (TIC)				2,276,586	
Project Contingency		15% of TIC		341,488	3
Total Plant Cost (TPC)				2,618,074	
Preproduction Cost		2 % of TPC		52,361	3
Inventory	6000 gal	1.35 $/gal		8,100	4 / 2
Total Capital Cost				2,678,535	
Annual Operating Cost				681,223	
Maintenance labor & Parts:		1.50%	40,178.03		
urea		al/hr (double CAA r	337,245		4
water		double GP 473	946		2
Electricity			50,000		2
Overhead Rate:		0			3
Taxes and Insurance:		0			3
Capital Recovery:		9.44% of TCC	252,854		2
Total Annualized Cost				**681,223**	

SNCR Control Cost

S/ton =	**2,128**
$/dv =	**10.40**

NOx

Boiler B26 - OverFire Air / Flue Gas Recirculation + Selective non-Catalytic Reduction

			Tons/Year	grams/sec
Boiler Capacity	25	MW		
Emissions			640	27
			Total Controlled Emissions	
Existing Control Efficiency	0%			
Control Efficiency 1	35%	OFA/FGR	224	9
Control Efficiency 2	50%	SNCR	208	9
Controlled Emissions			432	18
Emitted			208	9
Visibility Improvement - Seney	0.005	dv per gr/sec	0.09	deciview

Note: Boiler B26 uncontrolled emission rate = 0.68 lbs/mmbtu

OFA / FGR Cost:

Annualized Cost	**244,797**

SNCR Cost:

						Reference
Total Direct Cost (TDC)					1,897,155	
	SNCR			1,217,000		4
	Concrete			68,917		2
	Piping & Insulation			398,190		2
	Electrical			213,048		2
Indirect Cost (IC)		% of TDC			379,431	
	General Facilities	5%		94,857.75		3
	Engineering & Home Office	10%		189,715.50		3
	Process Contingency	5%		94,857.75		3
Total Installed Cost (TIC)					2,276,586	
Project Contingency		15% of TIC			341,488	3
Total Plant Cost (TPC)					2,618,074	
Preproduction Cost		2 % of TPC			52,361	3
Inventory	6000 gal	1.35 $/gal			-	4 / 2
Total Capital Cost					2,670,435	
Annual Operating Cost					562,301	
	Maintenance labor & Parts:		1.50%	40,057		3
	urea	adjusted SNCR only rate		219,209		4
	water	double GP 473		946		2
	Electricity			50,000		2
	Overhead Rate:		0			3
	Taxes and Insurance:		0			3
	Capital Recovery:	9.44% of TCC		252,089		2
Total Annualized Cost					**562,301**	

OFA/FGR + SNCR Control Cost

Annualized Cost =	**807,098**
S/ton =	**1,868**
$/dv =	**9.13**

NOx

Boiler B27 - Regenerative SCR				
Boiler Capacity	25	MW	Tons/Year	grams/sec
Emissions			640	27
			Total Controlled Emissions	
Existing Control Efficiency	0%			
Control Efficiency 1	70%	RSCR	448	19
Control Efficiency 2			0	0
Controlled Emissions			448	19
Emitted			192	8
Visibility Improvement - Seney	0.005	dv per gr/sec	0.09	deciview

Note: Boiler B26 uncontrolled emission rate = 0.68 lbs/mmbtu

RSCR Cost:

					Reference
Total Direct Cost (TDC)				6,100,000	1
	RSCR:				
Indirect Cost (IC)		% of TDC		2,013,000	
	Installation:	30%	1,830,000		1
	Owners Cost:	3%	183,000		2
Total Installed Cost (TIC)				8,113,000	
Annual Operating Cost				2,160,437	
	Maintenance labor & Parts:	1.50%	121,695		*3*
	Electricity:	see worksheet	365,574		1
	Ammonia Consumption:	5.81 tons/ ton NOx & 160$/ton	416,578		
	Ammonia Inventory:	12000 gal tank	7,186		1
	Natural Gas:	2.5 mmbtu/hr	146292		1
	Catalyst:	3 year	337,245		2
	Overhead Rate:		-		*3*
	Taxes and Insurance:		-		*3*
	Capital Recovery:	9.44%	765,867		2
Total Annualized Cost				**2,160,437**	

RSCR Control Cost

S/ton =	**4,821**
$/dv =	**24**

RSCR Electricity Worksheet

Enduse	Capacity		kW
booster fan	891	bhp	664
comb air fan	30	bhp	22
hydraulic power unit	8	bhp	6
ammonia pumps	0.5	bhp	0
instrument comp	15	bhp	11
misc instruments	2	kw	2
Hydraulic heaters, est.	1	kw	1
		Total kW	707

Annual Consumption	8760	hours / year	6,196,168
Annual Cost	0.059	cents / kWh	365,574

NOx

Boiler B27 - OverFire Air / Flue Gas Recirculation + Regenerative SCR

Boiler Capacity	25	MW	Tons/Year	grams/sec
Emissions			640	27
			Total Controlled Emissions	
Existing Control Efficiency	0%			
Control Efficiency 1	35%	OFA/FGR	224	9
Control Efficiency 2	70%	RSCR	291	12
Controlled Emissions			515	22
Emitted			125	5
Visibility Improvement - Seney	0.005	dv per gr/sec	0.11	deciview

Note: Boiler B26 uncontrolled emission rate = 0.68 lbs/mmbtu

OFA/FGR Cost:

Annualized Cost	**244,797**

RSCR Cost:

					Reference
Total Direct Cost (TDC)				6,100,000	1
	RSCR:				
Indirect Cost (IC)		% of TDC		2,013,000	
	Installation:	30%	1,830,000		1
	Owners Cost:	3%	183,000		2
Total Installed Cost (TIC)				8,113,000	
Annual Operating Cost				1,649,061	
	Maintenance labor & Parts:	1.50%	121,695		*3*
	Electricity:	see worksheet	-		1
	Ammonia Consumption:	1 tons/ ton NOx & 160$/ton	270,776		
	Ammonia Inventory:	12000 gal tank	7,186		1
	Natural Gas:	2.5 mmbtu/hr	146292		1
	Catalyst:	3 year	337,245		2
	Overhead Rate:		-		*3*
	Taxes and Insurance:		-		*3*
	Capital Recovery:	9.44%	765,867		2
Total Annualized Cost				**1,649,061**	

OFA/FGR + RSCR Control Cost

Annualized Cost =	**1,893,858**
S/ton =	**3,675**
$/dv =	**16**

References – Appendix B

1) Babcock Power Environmental, April, 2010; Equipment Quote to Georgia Pacific, *Green Bay Operations, Units 6, 7, 8, BPEI ROM Submittal 502477 – Rev 3,* Worcester, Ma.

2) Georgia Pacific, 2009, *Attachment B Engineering Analysis for Control Technology Options Green Bay Broadway Mill*. BART Analysis submitted to WDNR April, 2009.

3) USEPA, 2002, *EPA Air Pollution Control Cost Manual – 6th Edition*, Office of Air Quality Planning and Standards, EPA/452/B-02-001.

4) Combustion Components Associates, 2009, *Georgia Pacific Coal Stoker and Cyclone Boiler SNCR, RRI, OFA & FGR System Budget Proposal for Green Bay Mill*, prepared by Edmund Schindler, Monroe Connetticut.

5) USDOE, 2009, *Greenidge Multi-pollutant Control Project - Final Report of Work Performed*, DE-FC26-06NT41426.

6) WDNR, June 2010, *Best Available Retrofit Technology At Non-EGU Facilities,* Note 5, page 62, Wisconsin Department of Natural Resources, Madison, Wi.

APPENDIX C

Fuel Switching Analysis
for
Base SO_2 Emissions

WDNR, July 2011

Table C.1 Analysis for Adjusted B24 Base SO_2 Emissions

Parameter	2002	2003	2004	3-yr Average
Actual				
High Fusion Coal (tons)	25,204	8,264	6,474	13,314
% S High Fusion	---	---	---	---
Western Coal (tons)	0	2,241	5,981	2,741
% S Western	---	---	---	---
Actual SO2 Total Emissions (tons)	429	180	166	258
Adjusted				
%S High Fusion Coal	2.5	2.5	2.5	2.5
SO2 High Fusion (tons)	1,260	413	324	666
Replace Western Coal with High Fusion %S	2.5	2.5	2.5	2.5
SO2 High Fusion - Replacement of Western (tons) [1]	0	99	263	121
Adjusted SO2 Total Emissions (tons)	1,260	512	587	**786**

[1] Ratio of coal heat content for one ton High Fusion coal replacing one ton Western coal is assumed at 1.14.

Table C.2 Analysis for Adjusted B25 Base SO_2 Emissions

Parameter	2002	2003	2004	3-yr Average
Actual				
High Fusion Coal (tons)	34,847	11,526	8,308	18,227
%S High Fusion	---	---	---	---
Western Coal (tons)	0	2,982	8,407	3,796
%S Western Coal	---	---	---	---
Actual SO2 Total Emissions (tons)	588	246	213	349
Adjusted				
%S High Fusion	2.5	2.5	2.5	2.5
SO2 High Fusion (tons)	1,742	576	415	911
Replace Western Coal with High Fusion %S	2.5	2.5	2.5	2.5
SO2 High Fusion - Replacement of Western (tons) [1]	0	131	370	167
Adjusted SO2 Total Emissions (tons)	1,742	708	785	**1,078**

[1] Ratio of coal heat content for one ton High Fusion coal replacing one ton Western coal is assumed at 1.14.

Table C.3 Analysis for Adjusted B26 Base SO_2 Emissions

Parameter	2002	2003	2004	3-yr Average
Actual Emissions				
High Fusion Coal (tons)	45,060	18,112	894	21,355
%S High Fusion	1.01	0.96	0.96	
Low Fusion Coal (tons)	0	8,771	5,009	4,593
%S Low Fusion	2.33	2.36	2.43	2.37
Western Coal (tons)	9,997	33,588	64,601	36,062
%S Western	0.54	0.49	0.5	0.51
Pet Coke (tons)	10,971	12,084	14,119	12,391
%S Pet Coke	5.89	5.38	5.49	5.59
Actual SO2 Total Emissions (tons)	1,926	2,413	2,141	2,160
Adjusted Emissions				
%S High Fusion	2.5	2.5	2.5	2.5
SO2 High Fusion (tons)	2,253	906	45	1,068
SO2 Low Fusion - Estimated (tons)	0	414	243	219
Replace Western Coal with High Fusion %S	2.5	2.5	2.5	2.5
SO2 High Fusion - Replacement of Western (tons) [1]	440	1,478	2,842	1,587
Replace Coke with High Fusion %S	2.5	2.5	2.5	2.50
SO2 High Fusion - Replacement of Coke (tons) [2]	614	677	791	694
Adjusted SO2 Total Emissions (tons)	3,307	3,474	3,921	**3,568**

[1] Ratio of coal heat content for one ton High Fusion coal replacing one ton Western coal is assumed at 1.14.
[2] Ratio of coal heat content for one ton High Fusion coal replacing one ton Coke is assumed at 0.89.

Table C.4 Analysis for Adjusted B27 Base SO_2 Emissions

Parameter	2002	2003	2004	3-yr Average
Actual				
Low Fusion Coal (tons)	132,187	126,175	131,213	129,858
%S Low Fusion	2.33	2.37	2.43	2.38
Pet Coke (tons)	32,961	29,212	30,262	30,812
%S Pet Coke	5.89	5.38	5.49	5.59
Actual SO2 Total Emissions (tons)	8,807	8,810	8,527	8,715
Adjusted				
SO2 Low Fusion - Estimate (tons)	5,402	5,775	5,606	5,594
Replace Coke with Low Fusion %S	2.6	2.6	2.6	2.60
SO2 Low Fusion - Replacement of Coke (tons) [1]	1,846	1,636	1,695	1,725
Adjusted SO2 Total Emissions (tons)	7,248	7,411	7,301	**7,320**

[1] Ratio of coal heat content for one ton Low Fusion coal replacing one ton Coke is assumed at 0.93.

Table C.5 Analysis for Adjusted B28 Base SO_2 Emissions

Parameter	2002	2003	2004	3-yr Average
Actual				
High Fusion Coal (tons)	25,621	9,311	407	11,780
%S High Fusion	---	---	---	---
Low Fusion Coal (tons)	17,861	20,445	48,902	29,069
%S Low Fusion	---	---	---	---
Western Coal (tons)	25,056	28,399	11,455	21,637
%S Western Coal	N/A	N/A	N/A	N/A
Actual SO2 Total Emissions (tons)	1,664	1,656	942	1,421
Adjusted				
%S High Fusion	2.5	2.5	2.5	2.5
SO2 High Fusion (tons)	1,842	669	29	847
%S Low Fusion Coal - Estimated	2.33	2.36	2.43	2.37
SO2 Low Fusion - Estimated (tons)	832	965	2,377	1,391
Replace Western Coal with High Fusion %S	2.5	2.5	2.5	2.5
SO2 High Fusion - Replacement of Western (tons) [1]	1,102	1,250	504	952
Adjusted SO2 Total Emissions (tons)	3,776	2,884	2,910	**3,180**

[1] Ratio of coal heat content for one ton High Fusion coal replacing one ton Western coal is assumed at 1.14.

APPENDIX D

Fluor Daniel Study 2000 - Summary of Stack 10 Flows

Stack 10 Flow was tested; individual boiler flows are calculated values)

From Table 2 - Partial Load		
	Steam M lb/hr	AWCFM (319F)
Boiler 5 (hasn’t run in over a year)	34	38277
Boiler 6	174.6	118413
Boiler 7	439	152470
Boiler 8	132.5	119828
Infilt		67969
Total	780.1	496957

From Table 4 - Full Load		
	Steam M lb/hr	AWCFM (319F)
Boiler 5 (hasn’t run in over a year)	112.5	70755
Boiler 6	237	134705
Boiler 7	478.9	186175
Boiler 8	171.7	139891
Infilt		64121
Total	1000.1	595647

From Table 6 - Max Operation No flyash reinjection		
	Steam M lb/hr	AWCFM (319F)
Boiler 4 (no longer exists)	95.2	63894
Boiler 5 (hasn’t run in over a year)	96.8	44150
Boiler 6	223	138010
Boiler 7	467.8	199487
Boiler 8	168.9	142532
Infilt		57827
Total	1051.7	645900

From Table 8 - Max Operation With flyash reinjection		
	Steam M lb/hr	AWCFM (319F)
Boiler 4 (no longer exists)	99.3	66121
Boiler 5 (hasn’t run in over a year)	93	51777
Boiler 6	215	131456
Boiler 7	447.8	196493
Boiler 8	170	134892
Infilt		74861
Total	1025.1	655600

Section III. Response to Comments

The Department received comment to the draft BART determination from the Class I area Federal Land Managers, from Georgia Pacific – Green Bay, and from McGillivray, Westerberg & Bender LLC on behalf of Sierra Club of Wisconsin. The Department's response to these comments and how the issue affects the amended BART determination is described in this section.

1. Federal Land Managers

The Federal Land Managers agreed with the preliminary BART determination and emission requirement.

2. Georgia Pacific – Green Bay

The Draft Permit should clearly identify that the BART-derived Stack S10 limit doesn't apply when only one Boiler B28 (a non-BART boiler) is operating.

Response:
The Title V permit for Georgia-Pacific (GP) allows a compliance approach of either meeting an emission limitation for each individual BART boiler (B26 and B27), or an emission limitation for the common Stack S10. The common stack exhausts emissions from boilers B24, B25, B26, B27 and B28. If Georgia Pacific elects to comply with the individual BART boiler limitations then there is no requirement to comply with the common stack limit. Or in other words there is no emission limitation applicable to boilers B24, B25, or B28 if Georgia Pacific is complying with the individual BART boiler limits. The common stack emission limitations are applicable only if Georgia Pacific elects to demonstrate compliance on this basis.

Under this consideration however, Georgia Pacific cannot alternate the elected approach for demonstrating compliance. This aspect is important as certain actions such as curtailing boiler operation can be pursued to demonstrate compliance with one emission limitation format. In pursuing such an action Georgia Pacific cannot simply claim that the limits no longer apply because the boiler is not operating. Therefore, the permit requires Georgia Pacific to notify the Department 90 days prior to first establishing or when changing the election of emission limitation requirements for demonstrating compliance.

Best Available Retrofit Technology determinations are to be done one pollutant at a time.

- Georgia Pacific states that the analysis of individual control options should be based on pre-control conditions, e.g. the Department cannot presume any SO_2 reductions resulting from BART in the technical feasibility and operation of NOx controls, specifically RSCR.

Response:

The Department does not agree that individual pollutant controls should be evaluated one pollutant at a time in separate context. First, the evaluation of visibility improvement is synergistic between the pollutants with the emission reduction requirements to be implemented concurrently. Further, BART guidance is to evaluate controls in context of the existing equipment configurations and known conditions. Therefore the Department's approach is to evaluate controls accounting for actual existing or projected equipment configurations based on the most efficient control approaches in light of visibility improvement and the five factor evaluation criteria applied in the BART determination.

On this basis if SO_2 emission reductions required under BART is the basis for evaluating NOx controls. Therefore for the Georgia Pacific boiler system, the analysis of a RSCR or any tail-end SCR will assume placement after the reduction of SO_2 emissions. However, the Department also concludes that it is appropriate to consider the various SO_2 reduction approaches, under the existing equipment configuration, and their potential efficiencies for achieving the overall control requirement. As such, the evaluation of the RSCR technology applied to the GP boiler system also considers that the common flue duct splits prior to the existing fabric filter. Under this condition the most efficient approach may be to apply FGD and RSCR technology to one side of the split duct system (refer to the Section II.4).

Further, the Department considers different SO_2 control approaches in evaluating NOx controls based on solutions considered viable under the five factor analysis. For this reason, if a control approach such as shutting down one boiler significantly reduces total SO_2 emissions and but still results in high SO_2 flue gas concentrations from the remaining boilers then this condition will be considered in evaluating NOx BART controls. However, if other SO_2 control options are available and are equal under the five factors then these control options are used as the basis for evaluating NOx controls.

- Georgia Pacific considers that the cost of SO_2 controls as a pre-requisite for NOx control should be included in the cost of the NOx control system.

Response:
The department agrees that all costs should be counted in evaluating BART controls. Any portion of cost for SO_2 control incurred beyond the SO_2 BART requirement should be applied to evaluating the cost of NOx control. However, the full benefit of visibility improvement associated with any required SO_2 control, whether for SO_2 BART or NOx BART, would then also be included in the evaluation of overall visibility improvement.

In the determination of the amended GP BART requirements no control for SO_2 beyond that of the SO_2 BART is assumed as a pre-requisite to implementing NOx emission reductions. Conversely, the NOx BART determination looked at how SO_2 controls can be configured, in meeting the same SO_2 BART, in order to provide the most efficient use of RSCR NOx control equipment on one flue gas stream exiting the existing fabric filter system. In this manner the Department looked at how controls can be best integrated for the highest available NOx reduction, in context of the five factor analysis, in a manner which does not require reductions beyond SO_2 BART.

- Georgia Pacific concluded that the draft BART determination and default application of surrogate control equipment can preclude the technical feasibility of some emission trading options.

Response:
The BART emissions trading program is set forth under s. NR 433.06, Wis Adm Code. The requirements establish that any emissions trading program must demonstrate visibility improvement equivalent to that achieved through the BART level of controls. This approach clearly requires that the BART level of controls is established first and independently of emissions trading. Then the Department must set appropriate criteria for emissions trading which maintains visibility improvement garnered from the BART level of control. The Department must follow this approach and cannot account for all possible control strategies in establishing emissions trading requirements. Similar to BACT, the BART Determination and emission trading criteria allow Georgia Pacific to structure the best possible control approach meeting the BART determined requirements.

The Department has incorporated a default emissions trading compliance option under the BART compliance requirements. The Department concluded, based on analysis of technologies and cost, that the most likely emissions trading approach is to over-control SO_2 emissions from non-BART boilers at a lower cost rather than fully controlling NOx to the BART control levels. On this basis, mass emission caps and emissions trading ratios are set forth in Georgia Pacific's permit which can be utilized while fulfilling the emissions trading criteria under s. NR 433.06, Wis. Adm. Code.

Vendor data and performance guarantees do not determine BART absolutely.

Response:
The Department agrees that a vendor statement of performance is not the only factor to consider in determining a BART level of control. The Department's approach considered vendor information, control levels demonstrated by other operating units, and potential operating variability.

- Georgia Pacific specifically requested for the department to re-examine the technical feasibility of RSCR in light that no units have been installed for coal fired boilers or in conditions of high SO_2 flue gas concentrations.

Response:
The Department re-examined the applicability of RSCR in context of the existing flue duct configuration and potential flue gas SO_2 concentrations. The RSCR vendor provided a quote to Georgia Pacific for the Stack S10 system and further confirmed with the Department that RSCR is applicable to coal fired units. The vendor further identified implications for operating RSCR at different SO_2 flue gas concentrations. The Department finds that control strategies can be

implemented for reducing SO_2 concentrations under the SO_2 BART requirement which allows operating RSCR for control of boiler B27's portion of NOx emissions in the flue gas. This approach is based on the common flue duct splitting to two separate duct runs. The control of boiler B27 requires full RSCR control of one split duct.
The Department, however, found that SO_2 concentrations in the second duct are not conducive to operating RSCR to control boiler B26's portion of NOx emissions in the flue gas. Under the BART five factor analysis RSCR was eliminated as a control option for boiler B26.

Operating variability must also be considered in determining BART.

The emission requirement set for BART needs to incorporate the operating variability into a compliance margin, i.e. an enforceable operating permit limit should provide the permittee an appropriate level of operating flexibility to allow the facility to achieve continuous compliance with all permit limits.

Response:
The Department agrees that the long-term performance of control equipment and operating variability must be considered in establishing a reasonably achievable control level and emission limitation. In this context, the Department believes the emission limitations set for the Georgia Pacific boilers on a 30 day and 12 month rolling basis address normal operating variability (refer to Section II.6).

The Department addressed control levels and compliance margins as follows for SO_2 and NOx.

<u>SO_2</u>
The draft BART determination proposed control levels of 95% removal based on circulating fluidized bed technology as represented by TurboSorb. The Department reviewed emissions data for operating Turbosorb units and engineering assessments for CFB technology. The Department adjusted the SO_2 BART control efficiency from 95% to 93% removal in setting BART compliance requirements. Refer to Section II.2 for the determination of SO_2 BART control levels

<u>NOx</u>
The draft BART determination proposed control levels of 84% for boiler B26 and 92% for Boiler B27. Under the amended determination the BART compliance requirement is based on NOx control levels of 68% and 84% for boilers B26 and B27, respectively. These emission limitations are determined with incorporated compliance margins for the surrogate control equipment. Refer to Section II.4 for the determination of NOx BART control levels.

The visibility improvement metric used by WDNR in determining BART is insufficient.

The BART guidelines specify that an initial criterion for visibility benefits is the change in days above a 0.5 deciview impact. To completely evaluate the differences between options, the determination needs to include this information.

Response:
The 0.5 deciview is a threshold under the Regional Haze requirements which identifies eligible facilities to be evaluated for BART controls. The rule does not specify that further emission reductions are not necessary once the 0.5 deciview threshold is achieved. The amount of deciview impact for the Georgia Pacific boilers and the amount of improvement resulting from the BART controls is estimated in the BART determination. The maximum day visibility impact from uncontrolled emissions to the Seney Class I area is 5.38 deciview. Under BART, the maximum daily impact is estimated to decrease to 2.02 deciview and the number of days above 0.5 deciview decrease by an estimated 29 to 34 days. These results show that a change greater than 0.5 deciview is achieved and that days are reduced.

- Georgia Pacific requests, consistent with BART guidelines, that the Department not consider imperceptible visibility changes (in evaluating controls for BART).

Response:
The Department assessed small changes in visibility when evaluating control technologies. The CALPUFF model used in estimating visibility impacts for a source defines deciview changes in 0.01 increments. The Department agrees this increment by itself is imperceptible to visibility. However, small changes in measured visibility improvement, due to emission reductions from the same source and with other sources, contribute to overall improvements in visibility. Therefore, under the top-down BART approach control technologies are evaluated based on the resulting <u>total</u> visibility improvement. The amended BART requirement is estimated to yield visibility improvement for Seney of 0.52 deciview from NOx reduction and 1.23 deciview from SO_2 reductions (average of 3 year maximum daily impact). Therefore the control technologies and associated emission reductions yield significant changes that contribute to perceptible visibility improvement.

The Department did evaluate the increment of visibility improvement between two technologies when the control envelope defines a significant cost increase between the top-available control and the next tier down. For example, the Department determined wet-FGD could cost on the order of two times the cost of dry-FGD with little additional SO_2 control. Wet FGD produced only a maximum 0.09 improvement versus dry-FGD in visibility for the Seney Class I area. The dry-FGD garners a maximum 1.23 dv improvement. Therefore wet-FGD is eliminated as a BART control option because dry-FGD produced nearly equivalent visibility improvement. Similar approaches are used in comparing SCR, RSCR, and SNCR based control options in the NOx BART determination.

- Additional Particulate Matter requirements are unnecessary.

Response:
The Department agrees that no additional requirement for particulate matter is necessary under the BART requirement. The Department modeled potential control efficiency improvements to the existing fabric filter system compared to the existing permit limit. This increased control

resulted in a maximum of 0.04 dv visibility improvement. In context that this visibility improvement is the entire result of a control measure the Department deems this level of visibility improvement as marginal in contribution to a perceptible visibility change.

Allowable emissions for both BART and non-BART boilers should be used to establish proposed Stack 10 permit limits.

Response:
The Department does not agree that permit limits for BART and non-BART boilers are the basis for establishing Stack 10 requirements. Refer to Section II, Table 3.3 for a comparison of allowable and actual emissions. The emission requirements are to be set based on the determined BART control efficiencies and an assessment of reasonable operating conditions for the entire boiler system (refer to Section II.3 for SO_2 base emissions). On this basis the Department determined a base fuel for adjusting uncontrolled SO_2 emission baseline. The base fuel assumes sulfur content reflecting bituminous coals. The SO_2 emission requirement is then calculated using this adjusted SO_2 base emissions. The setting of the NOx emission limit is based on current actual emission rates. These rates are related to boiler combustion parameters and therefore reflect expected ongoing uncontrolled emissions.

WDNR needs to calculate incremental cost effectiveness of proposed control analysis.

Response:
The Department staff performed a top-down analysis of the available control technologies and control levels. As part of this analysis, the Department staff provided the costs associated with each control technology and control level. The Department evaluated incremental costs and visibility impacts when the control envelope of control options demonstrated a significant increase in cost versus the resulting visibility improvement.

3. Sierra Club of Wisconsin

DNR must also establish BART limits for EGUs.

Response:
The Department established BART limits for EGUs. The state BART rule, ch. NR 433, Wis. Adm. Code, establishes that EGUs satisfy SO_2 and NOx BART if complying with the federal Clean Air Interstate Rule (CAIR). The Wisconsin EGUs elected this compliance option. With the implementation of the Clean Air Transport Rule (CATR) to replace CAIR the Department will have to evaluate if EGUs still satisfy the SO_2 and NOx BART requirement. For PM BART, the Department evaluated control options and determined existing controls constitute BART.

Control technologies with costs less than 51 M$/dv should be considered for BART.

Response:
The Department applied the top-down approach required under BART in evaluating control options. Under this approach, contribution to visibility improvement and the necessary cost, expressed as M$ per deciview, is a primary evaluation criteria. As Sierra Club states on this basis all evaluated control options appear cost-effective. However, the BART guidelines also provide that marginal or incremental cost should be considered and that a control envelope should be developed representing the available control options. This information can be used to evaluate the relative magnitude of visibility improvement versus cost between the top-tier options. The Department applied this method in determine controls representing BART. In addition the BART guidance requires consideration of non-cost factors in making a BART determination. The Department applied these criteria in establishing BART. Addressing both factors eliminated several top-tier control options as the basis for BART.

Wet Scrubber Technology is available at lower cost and can achieve greater than 98% reduction.

Response:
See WDNR response to Comment 2 from Sierra Club above. In the BART preliminary determination, WDNR viewed wet FGD at 95% and 98% control as inappropriate due to it's incremental visibility improvement and cost-effectiveness, and energy and environmental impacts, compared to dry FGD. The wet FGD costs were based on GP's BART submittal. The comment from Sierra Club offers no alternative cost to refute the costs presented by WDNR. Wet FGD above 98% control remains inappropriate in terms of cost-effectiveness and energy and environmental impacts compared to dry FGD.

The Department needs to consider fuel switching to low sulfur coal and natural gas as a control option.

Response:
In the final determination for GP, the Department utilizes a base coal to replace the historical use of petroleum coke. This base fuel is a bituminous coal with 2.5% or 2.6% sulfur content depending on the boiler, compared to coke at 5-6 % sulfur content. The Department evaluated the effectiveness of various levels of fuel switching including the use of low sulfur bituminous coal and subbituminous coal. The low sulfur bituminous coal does not yield additional benefit compared to the use of standard bituminous coal when applying the dry FGD 93% control efficiency. The Department considered switching to subbituminous powder river basin coal as beyond the scope of BART under the five factor analysis. Refer to Section II.3 for detail discussion of this analysis.

Regarding the use of natural gas instead of coal, US EPA states in Appendix Y "note that it is not our intent to direct States to switch fuel forms, e.g. *from coal to gas*."

The proposed emission limits do not represent the degree of control represented by BART.

- Assuming emissions for B24 and B25 which have not operated for several years creates a less stringent requirement.

Response:
The Department has determined that including B24 and B25 historic operation levels in setting emission requirements for stack S10 is appropriate. The BART guidelines specify using emissions from the baseline years, 2002 to 2004, as the default basis for establishing BART. During this baseline period these boilers operated as part of the stack S10 boiler system. Even as these boilers have not recently operated the Stack S10 system has demonstrated the use of this capacity. The Department finds that applying the heat input from boilers B24 and B25 to the operating levels of the remaining boilers during baseline year operation does not exceed their capacity. Therefore, the Department uses the average operating level (heat input) during the baseline years as the basis for establishing Stack S10 requirements. The Department also finds adjusting SO_2 base emissions to reflect an assumed "base" fuel for each boiler is appropriate to account for variability of fuel sulfur content and fuel switching control options. (Section II.3)

- Potential future control requirements for B24, B25 and B28 may create a less stringent requirement for the BART boilers. The Department must ensure that boilers B26 and B27 are meeting BART-level emission reductions during all operating scenarios.

Response:
The Department cannot anticipate or regulate based on *future* potential requirements. As the BART guidelines establish the BART determination should consider the existing equipment configuration and operations. Under this consideration, the emissions exiting from stack S10 cannot be distinguished as originating from BART or non-BART boilers. Therefore allowing compliance with either the individual boiler requirements or common stack requirements is appropriate and reflects a reduction of total emissions versus the baseline year emissions. In fact, establishing the alternative Stack S10 requirements establishes a baseline for BART and non-BART boiler operation. This compliance approach, if utilized, addresses the appropriate benchmark against simply shifting load between boilers.

The Department has not shown that the proposed limits will protect air quality (increased increments and NAAQS for NO_2, SO_2 and PM2.5).

Response:
The BART requirement is a requirement for visibility improvement under the federal Regional Haze rule. The air protection standards referenced by Sierra Club are not applicable to the BART determination. However, the Department agrees that compliance with these requirements must be demonstrated under the applicable regulatory programs.

The Department must clarify the sequence of permits for Georgia Pacific.

Response:
The Department is in the process of renewing the permit for Georgia Pacific. The process for incorporating BART requirements is separate from the renewal process but subject to public comment as well. Both processes for modifying the permit will proceed separately with requirements effective as each revision is finalized.