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SENT VIA EMAIL AND CERTIFIED MAIL – RETURN RECEIPT REQUESTED
Mr. Jonathan Loftus
WDNR Bureau of Air Management AM/7
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Subject: Georgia-Pacific comments concerning Wisconsin Regional Haze SIP proposed by Wisconsin Department of Natural Resources in July 2011

Dear Mr. Loftus:

Georgia-Pacific ("GP") appreciates this opportunity to provide comments to the Department of Natural Resources ("WDNR", or "the Department") concerning the Wisconsin Regional Haze State Implementation Plan proposed by the Wisconsin Department of Natural Resources in July 2011. As you are aware, GP's Green Bay - Broadway Mill (Facility ID: 405032870) has two boilers subject to Best Available Retrofit Technology (BART) rules identified as Boilers B26 and B27, and several other industrial boilers not subject to BART.

GP submitted a Best Available Retrofit Technology Analysis to the Department in March 2009. Since that time, GP and the Department have engaged in discussions in an effort to define a BART regulatory solution that provides significant and sufficient environmental results while preserving operational flexibility for GP in full accordance with the BART rules. We believe the solution identified in the WDNR's *"BART Determination – Amended July 2011. Georgia-Pacific Broadway Mill, Green Bay Wisconsin"* meets these goals. Specifically, we believe that the proposed BART determination for non-EGUs results in a workable solution that improves the visibility in affected Class I areas without unduly tying the Mill's hands with respect to future operating decisions. We appreciate all your efforts to date in working through issues necessary to achieve this solution.

The proposed permit presents a menu of compliance options that result in at least equivalent haze reduction when compared to the traditional BART analysis that pairs each BART boiler with each BART pollutant. Traditional BART results in six separate determinations (Boiler 6 and Boiler 7 each for particulates, sulfur dioxide, and nitrogen oxides). For GP, this traditional analysis leads to very narrow compliance demonstration options given that the BART boilers exhaust to a common stack with other non-BART boilers. Emissions monitoring is currently only conducted in the combined stack (and that is the only appropriate place for this monitoring), so emissions contributions from individual boilers cannot be determined absolutely from direct monitoring when firing more than one boiler. For this reason, a mass cap option that considers BART and non-BART boilers with a pollutant trading provision appears to be the most straight-forward and reasonably achievable compliance demonstration for us. As currently written, it is likely that GP would commit to this "mass cap with pollutant trading" alternative over the others.

Please see specific comments below pertaining to the amended BART determination. As WDNR may receive comments from other parties during the comment period and/or at the public hearing, GP may offer additional comments as appropriate prior to the end of the comment period.

Pages 56 and 70 of the draft permit requires that Boilers B26 and B27 meet current standards for particulate emissions and visible emissions in addition to following a malfunction prevention and abatement plan no later than December 31, 2011.

Georgia-Pacific supports these permit conditions. However, we disagree with any implication, intended or unintended, that this revision from the previous draft permit for BART would result in an increase in particulate matter emissions or in some form of "backsliding" from the previous BART determination.

On page 2 of the July 2011 GP BART document, WDNR states the following with respect to changes in the BART proposal from a previous version:

"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."

Then, on page 6 of the same document, WDNR states:

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

Georgia-Pacific agrees with the conclusion reached by WDNR as identified on page 6 that any additional plan or plan documents would not result in a decrease in particulate emissions or in an improvement in visibility.

<u>Pages 58, 63, 72, and 77 of the draft permit require that Boilers B26 and B27 meet proposed BART requirements for sulfur dioxide and nitrogen oxides no later than December 31, 2015.</u>

Georgia-Pacific offers three distinct concerns regarding this date. First, the permit language should be clarified with respect to what is required by or starting on the date mentioned, in light of the rule language found in Wisconsin Administrative Code at Chapter NR433.05 (1)(a)4., which states, with respect to what is required in a BART determination, the following: "... *the owner or operator of each source subject to BART shall install and operate BART as expeditiously as practicable, but in no event later than December 31, 2015.*"

If Georgia-Pacific installs and operates BART on December 31, 2015, Georgia-Pacific cannot and should not be expected to have to incorporate prior data into any kind of averaging period for the purposes of demonstrating compliance with proposed BART limits at that time. The permit needs to be very clear on this and GP suggests that the permit refer to the following time markers for the BART limits where no trading is involved absent any other considerations:

- December 31, 2015, should be the first day of the first 30-day rolling average or 30-day period for which a BART limit would be applied.
- January 2016 should be been the first month of the first 12-month rolling average or 12-month period for which a BART limit would be applied.

Second, we are concerned about how the December 31, 2015, date was established. Toward that end, GP offered comments to the Department on February 5, 2010, in support of a proposed compliance date of December 31, 2017, and asked the Department why the 2015 date was chosen. In a March 3, 2010, letter from John Melby, Jr. (WDNR) to Rob Bermke (GP), Mr. Melby responded by citing several dates related to PM2.5 and sulfur dioxide ambient air quality standards that supported a 2015 BART compliance date. He also suggested that GP may want to provide additional comments during the public comment period on this matter. One date cited by Mr. Melby was December 14, 2009, for the effective designation date of areas that failed to comply with the PM2.5 standard. However, in October 2009, EPA determined that Brown County, Wisconsin, was not to be classified as "non-attainment" for PM2.5, so this standard has no relevance to the compliance date for the proposed reductions at this time.

Likewise, WDNR recommended to EPA that Brown County, Wisconsin, was not to be classified as "non-attainment" for SO2, so this standard has no relevance to the compliance date of the proposed reductions at this time either. However, we expect by June 2013, WDNR will conduct modeling of all major sources, including the Green Bay Broadway facility for the SO2 NAAQS. As the compliance date for the SO2 NAAQS is August 2017 for non-attainment areas, we believe that August 2017 is the earliest plausible date for emission reductions to address SO2 NAAQS issues. Until such time that SO2 NAAQS is an issue for Brown County, the county remains unclassifiable and the NAAQS should not influence the compliance date for BART.

Third, the permit should clearly note that the trading plan identified on pages 64-65 and 78-79 of the permit is not "BART". Indeed, WDNR did not identify the trading plan as "BART" when summarizing compliance requirements in Table 3 (page 5), Table 6.1 (page 32), or Table 6.2 (page 33) of the July 2011 amended BART determination for GP. The trading plan would therefore not be subject to the December 31, 2015 deadline. Rather, the trading plan should be considered an approved Emissions Trading Program under NR433.06, as WDNR has used the criteria outlined in this section of code for its evaluation (see discussion beginning page 33 in the

July 2011 document).[1] Please see GP's comments to Mr. Tom Karman (WDNR) on May 7, 2010 which we summarize here:

Wisconsin Adminstrative Code at Chapter NR433.06(2) states *"If the department approves the emissions trading plan, 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."*

A plain reading of this says that a source identified as BART that operates under an approved trading plan is meeting emissions reductions in lieu of a BART determination. NR433.05 (1)(a)4. only addresses a BART installation date for an actual BART determination (as opposed to a date for a trading plan that results in *"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."(NR433.06(1))).*

GP believes that the compliance date flexibility afforded by USEPA's Clean Air Visibility rule at 40 CFR 51.308(e)(2)(iii) should be mirrored in GP's trading plan requirements. That rule identifies *"A requirement that all necessary emissions reductions take place during the period of the first long-term strategy for regional haze".*

This means that emissions reductions from a trading program would need to begin before the start of the next planning period, which is January 2018. With this in mind, GP proposes the following dates for its trading option:

- December 31, 2017, would be the first day of the first 30-day rolling average or 30-day period for which a BART limit would be applied.
- January 2018 would be the first month of the first 12-month rolling average or 12-month period for which a BART limit would be applied.
- If Brown County becomes classified as non-attainment for SO2, these dates can be adjusted at the time of SIP approval by EPA, but shall be no earlier than July 31, 2017.

These dates would afford GP of the opportunity to make informed strategic decisions that best protect the interests of both the environment and the Mill by allowing us more time to collaborate with consultants, technology experts, and control equipment manufacturers who already face very tight deadlines assisting clients due to this and other regulatory programs.

<u>Proposed sulfur dioxide limits on pages 58, 59, and 73 of the draft permit</u>

There are several considerations that drive these proposed limits and they include the concepts of fuel switching and asset utilization allowances to redefine baseline emissions rates followed by 93% sulfur control using a fluid bed scrubber system.

Regarding the aspect of fuel switching, WDNR stated the following on page 17 of the July 2011 document:

"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.

[1] In fact, the trading plan meets both the 10% reduction and 10% visibility criteria in NR433.06 when it really only needs to meet one of them. Page 33 incorrectly says the plan needs to meet both.

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 SO2 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 SO2 emission requirements applicable to the Stack S10 boiler system."

Currently, to satisfy existing air permit compliance requirements, GP primarily burns lower sulfur-containing coals with a small percentage of petroleum coke. The WDNR analysis assumes that petroleum coke would no longer be fired in Boilers B26 and B27 as part of a BART solution prior to looking at add-on control technology. To evaluate an operating condition without petroleum coke, a control technology analysis should reflect fuel purchases from our existing suppliers during the baseline period which would include coal with a sulfur content up to 2.5%, as this sulfur coal was generally available at a higher unit price during that period.

According to Table 3.3 of the WDNR July 2011 document, the two BART units, B26 and B27, actually emitted 10,875 tons of SO2 per year as a 3-year baseline average prior to looking at any fuel adjustment. After removing petroleum coke and adjusting the sulfur content of other fuels to what would have been (and is) reasonably available, the emissions of the same MMBTU of fuel increase by only 14 tpy of SO2 over base year actual emissions without the adjustment. This is less than a 1% difference.

Regarding non-BART boilers and their contribution to mass cap limits, GP has previously expressed concern to the Department about the potential erosion of their allowable limits when setting the mass cap. We still have that concern. However, we also understand that a workable solution must allow some compromise if the compliance demonstration depends on measurement in the common stack. In that spirit, GP supports WDNR's adjusted base year calculations that rely on opportunity fuel with respect to sulfur content for the non-BART boilers as identified in Table 3.3 of the July 2011 document. These base year emissions from non-BART boilers then get carried over to establish the annual mass cap without control. Even absent add-on control, it should be noted that this results in 585 less tons of SO2 emitted in the cap from the non-BART boilers when comparing the allowable emissions to the adjusted base year emissions, despite the fact that these boilers are not subject to BART reductions. These non-BART boilers are all stoker design and burn fuel from common onsite bituminous coal stockpiles that also serve Boiler B26 which is subject to BART. Thus, having a common base fuel for all stoker boilers is an appropriate assumption.

In addition to fuel switching, another consideration that goes into establishing the baseline SO2 mass cap is asset utilization. The Department has chosen to use the average MMBTU heat input for the three baseline years for each BART and non-BART boiler in this analysis. For the BART boilers (B26 and B27), this baseline MMBTU reflects only 74% of the full capability of these boilers. So, absent every other consideration used to establish the cap, over 3000 tons of potential emissions are reduced simply due to not allowing credit for operating these BART boilers at their full ratings in the future.

Likewise, for the Stack S10 non-BART boilers, WDNR credits 2,529,603 MMBTU to establishing the baseline cap based on the average of the three baseline years. If GP ran Boilers B25 and B28 at maximum allowable rates (as both of these boilers are still active boilers accounted for in the Annual Emissions Inventory and in the facility's Title V permit dated July 26, 2011), we would realize 3,810,600 MMBTU per year heat input to these boilers. So, in a combined stack solution absent any other consideration, GP is only credited for 66% of its potential heat input in the calculation of allowable emissions from non-BART boilers for SO2. For these reasons, GP believes it entirely appropriate for WDNR to include emissions from all three of the non-BART boilers that operated during the baseline period (Boilers B24, B25, and B28) in the baseline emissions calculations.

While GP would have preferred for this calculation to allow for the full boiler ratings for both BART boilers and, especially, non-BART boilers, we had suggested verbally to the Department that we would submit to the single highest MMBTU year in the baseline for the purposes of making these calculations. Using the three-year average heat input does not properly account for demand variability.

The final consideration to be addressed here concerns the percent reduction of SO2 due to control equipment. WDNR stated the following on Page 2 of the July 2011 document:

"The draft finding proposed SO2 requirements based on application of dry scrubbing circulating fluidized bed (CFB) absorber technology achieving 95% control of SO2 emissions. The department developed costs and control levels based on a commercially available CFB unit called Turbosorp.

The BART determination for SO2 is amended to reflect that CFB technology is capable of meeting a 93% long-term compliance requirement".

The CFB absorber technology is an innovative technology with a growing number of applications, but as of 2011, there are still a limited number of full-scale installations to evaluate. GP contacted Babcock Power Environmental, a supplier of CFB absorber technology, to compare the actual performance guarantees versus the best performance during initial start-up of the full-scale installations. While some source tests have demonstrated emission reduction efficiencies above 93%, the supplier only specifies emission guarantees based on concentrations or emission rates per unit of heat input. Babcock Power only designs its equipment to meet a guaranteed mass emission rate (e.g., ppm or lb/MMBtu) and does not guarantee emissions reduction efficiency[2]. For instance, the installation of this technology on Deerhaven Unit #2 at the Gainesville (FL) Regional Utilities site in 2010 is only guaranteed to meet a specific lb/MMBtu emission rate. An emission reduction efficiency value is not included in the air permit or guaranteed by the vendor.

The most recent approved air permit for a CFB absorber system that we are aware of is the Fairfield Renewable Energy Project, in Baltimore, Maryland. The application is for a waste-to-energy plant with a lower SO_2 inlet concentration than either of the GP Broadway boilers. The proposed BACT limit and emission guarantee for the Fairfield Renewable Energy Project was set at 28 ppmvd. While the mass emission rate guarantee is independent of a percent reduction efficiency value, the estimated percent reduction stated in the Certificate of Public Convenience and Necessity was 85%.

GP agrees with WDNR's revised BART determination that reflects a 93% SO_2 emission reduction. During the 2007 through 2009 testing of the AES Greenidge Unit #4 in Dresden, New

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[2] Email from John Bowman (Babcock Power) to Mark Aguilar (GP) dated September 7, 2011.

York, the observed SO_2 emission reduction efficiency varied from 85% to greater than 93%.[3] Assuming a normal distribution, approximately 18% of these observations were below 93% reduction. The high degree of variability in the reported SO_2 reduction efficiencies supports the need for the BART determination to be based on a reduction efficiency that reflects performance of the controls over long term operating conditions, not simply the highest demonstrated test.

Any suggestion that 93% provides too much of a "compliance margin" needs to be considered in the context that GP's case concerns the retrofit of existing industrial boilers, as opposed to a greenfield installation with generally greater design latitude. For this reason, vendors generally guarantee to a less aggressive level of emissions control for retrofits than for a new installation where other operating conditions can be designed in or planned for.

The BACT determination for a CFB boiler for Red Trail Energy plant in North Dakota represents the most recent PSD permit for an industrial boiler. The Potential-To-Emit (PTE) for an SO2 system on that unit as reported to the RACT/BACT/LAER Clearinghouse (RBLC: Determination ND-020) was computed using an annual average of 93% reduction for a "pounds per MMBTU" limit over 30 days[4]. Greenfield CFB boilers are setting BACT at 95% because they are CFB boilers.

Proposed nitrogen oxide limits on pages 63, 64 and 78 of the draft permit

There are several considerations that drive these proposed limits and they include the concepts of asset utilization allowances, baseline emissions rates in pounds/MMBTU for each boiler, and the efficiency of add-on control equipment in reducing nitrogen oxide emissions.

Regarding the first two of these considerations, asset utilization allowances were discussed in detail in the sulfur dioxide section above, and all those arguments hold for nitrogen oxides as well. The boiler-specific baseline emissions rates used are reasonable and supported by well-established emissions factors or actual monitoring data.

The issue of control efficiency will be addressed here. WDNR stated the following on Page 2 of the July 2011 document:

"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

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http://www.netl.doe.gov/technologies/coalpower/cctc/PPII/bibliography/demonstration/environmental/greenidge/GreenidgeProjectFinalReport-5-27-09.pdf Table 25.

4 Taken from
http://cfpub.epa.gov/rblc/index.cfm?action=PermitDetail.PollutantInfo&Facility_ID=25986&Process_ID=103642&Pollutant_ID=192&Per_Control_Equipment_Id=137952

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."

And, on page 18:

"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)"

GP agrees with the revised BART determinations that are based on a 68% control efficiency for Boiler B26 resulting from combustion modifications and selective non-catalytic reduction (SNCR), and an 84% control efficiency for Boiler B27 from overfire air followed by RSCR, rich-reagent injection (RRI), or SNCR. By performing a top-down analysis on each boiler, the marginal and incremental cost effectiveness values are more accurate. Boilers B27 is a cyclone furnace, firing bituminous coal and petroleum coke, whereas Boiler B26 is a stoker boiler firing bituminous coal and petroleum coke. Typical uncontrolled NOx emission rates for stoker-designed furnaces and cyclone-designed furnaces vary significantly. EPA's AP-42, Compilation of Emission Factors, reports NOx emissions of 33 lbs/ton and 11 lbs/ton[5], for cyclone-designed and stoker-designed furnace configurations, respectively. Performance of controls is also a function of boiler design. BACT determinations consistently show that boilers with stoker-designed furnaces can be well controlled with combustion modifications and/or the application of SNCR. Due to the tall internal furnace height of Boiler B26,, there is sufficient residence time inside the furnace for an SNCR system to reduce NOx emissions by more than 40%. Once the application of SNCR is considered, the incremental cost effectiveness for using a control technology with a higher emission reduction efficiency, such as RSCR, is too great to be considered economically feasible. The marginal cost effectiveness values for a combination combustion modification and SNCR system versus an RSCR case, as reported by WDNR in Table 4.4 of the amended determination, are 1,868 and 4,821 \$/ton, respectively. The incremental cost effectiveness for the additional tons controlled by an RSCR system is equal to:

$$\frac{(2{,}160{,}437 - 807{,}098)\ \$/\text{yr}}{(448 - 432)\ \text{tons removed/yr}} = \$84{,}583/\text{incremental ton NOx.}$$

In its 2007 Final Statement of Basis for Deseret Power Electric Cooperative, USEPA stated that an incremental cost effectiveness value of $10,540 per ton of pollutant removed was "too high to justify the expenditure"[6].

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[5] http://www.epa.gov/ttn/chief/ap42/ch01/final/c01s01.pdf Table 1.1-3 page 1.1-18
[6] http://www.epa.gov/region8/air/pdf/FinalStatementOfBasis.pdf page 95

Therefore, GP agrees that the selection of combustion modifications and selective non-catalytic reduction (SNCR) with a 68% NOx control efficiency for Boiler B26 is appropriate as BART and that higher levels of control are not economically feasible.

Similar to the discussion above for B26, once the application of multiple systems with SCRs are considered, the incremental cost effectiveness is too great to be considered economically feasible for B27. The marginal cost effectiveness values for a OFA/RRI/SNCR case versus an OFA/SNCR/IDSCR case, as reported by WDNR in Table 4.2 of the amended determination, are 817 and 965 $/ton, respectively. The incremental cost effectiveness for the additional tons controlled by an SCR system is equal to:

(2 ,242,797– 1 ,872,794) $/yr
------------------------------------ = $11,563/incremental ton NOx.
(2,324 – 2,292) tons removed/yr

GP believes that this incremental cost effectiveness is too high and that the proposed determination of 84% is aggressive, but appropriate.

<u>Appendix B of Appendix F (the July 2011 document) :</u>
<u>Control Equipment Costing Sheets for Georgia-Pacific BART Boilers SO2 and NOx</u>

The cost estimates provided by GP as part of its BART analysis were based on a +/- 30% to +/- 50% level of accuracy. While several cost estimates included a process contingency or a project contingency factor, no contingencies are included in the cost estimates provided for RSCR. The cost estimates we provided for NOx control options with RSCR have the most uncertainty due to a lack of site-specific installation cost data. The budgetary cost estimates for the RSCR control equipment are specific to the use of this equipment at our site. However, the installation costs we used are based on the use of a generic cost factor from the equipment supplier. To estimate contingency costs for the RSCR control system, we assumed 5% of equipment costs and 15% for the total of direct and installation costs for SCR control systems from Table 2.5 of OAQPA Cost Control Manual.[7]

Using these default conservative contingency values, the total installed cost value of $8,113,000 presented in Appendix B would increase to:

$6,100,00 x 1.05 = 9,150,000 Total Direct Cost (TDC)

Total Installed Cost = ($2,013,000 Indirect Cost + $9,150,000 TDC) x 1.15 = $12,837,450

With a TIC of $12,837,450 instead of $8,113,000, the annualized cost for all RSCR options should be increased by:

($12,837,450 – $8,113,000) x 9.44% = $445,988 /yr.

WDNR should revise the previously submitted cost effectiveness values using these higher annualized costs which reflect the use of more conservative EPA contingency factors. The cost effectiveness values presented in the previous BART determinations were underestimated by not using the contingency factors.

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[7] http://www.epa.gov/ttn/catc/dir1/c_allchs.pdf

For example, the total annualized cost for an RSCR control system plus overfire air for Boiler B27 would be revised from $2,818,927 to $3,264,915. Applying the additional annual cost also adjusts the cost effectiveness value from $1,215 / ton to $1,407 / ton removed.

Derivation of short-term (30-day) average limits

WDNR's 30-day limits are based on the maximum actual highest heat input day in the baseline period for each of the boilers. While GP would have preferred for this calculation to allow for the full boiler ratings for all units, we agree that using the maximum actual day is an acceptable approach. Using any other longer averaging time to establish this rate would compromise operational flexibility and inadequately account for demand variability.

Emissions trading proposal identified in the draft permit

GP supports the use of the value "T = 2.0" as the ratio of (sulfur dioxide tons reduced from 5,800 tons) to (nitrogen oxides tons increased from 1080 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 to demonstrate compliance as established and supported in great detail in WDNR's July 2011 document. Clearly, the trading of emissions using this ratio maintains or improves GP's effect on visibility when compared to the BART limits. We commend the Department for examining and allowing the use of trading among pollutants as an innovative and effective technique to achieve improvements in visibility, as GP is unaware of any State or Federal BART rules or guidance that prohibit its use. In a typical top-down analysis for BACT, EPA Guidance (Draft NSR Manual 1990) instructs the analyst, when comparing two technologies of similar emission reduction, that only the lower cost choice is needed for comparative analysis. In a similar way, by incorporating trading between pollutants, GP chooses the lowest cost choice among options that yield the same visibility benefit. Cost of compliance is a factor in determining BART, and inter-pollutant trading for this specific example consistently applies this factor.

Summary

We will continue to work closely with the Department as our comments as well as the comments of others are evaluated. We believe that the current WDNR proposal is adoptable in its present form as a whole, despite many of the individual concerns we have expressed here. Should any individual issues identified require additional attention, we would ask that the Department please consider those issues in light of the common goal of improving visibility in the Class I areas through the BART process. As those improvements are driven by the quantities of certain emissions over time, it appears almost intuitive that the best approach is reflected in common stack mass limits for SO_2 and NO_x with the ability to trade pollutants in a way that reflects sound science as to impacts. We believe the WDNR has achieved that with this proposal as a whole.

Sincerely,

Randall Harbath

Randall Harbath
Vice President - Manufacturing
Green Bay Broadway