September 16, 2011

VIA Electronic Mail

Jonathan Loftus
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Re: Public Comments on DNR's Draft Visibility SIP

Jon:

These comments are submitted on behalf of the Sierra Club, the Midwest Environmental Defense Center, and their members. Sierra Club previously commented on a prior draft of the BART determinations and most of those prior comments are still applicable, including the need for boiler-specific emission limits. We are attaching and incorporating those prior comments herein by reference.

The prior BART analysis done by DNR for the Georgia Pacific plant is demonstrably better supported by the facts and analysis (while still suffering a few errors as set forth in our prior comments), than the current proposed limits. The current proposal results in thousands of additional tons of pollution.

To generally summarize our position related to the Georgia Pacific BART limits proposed by DNR, we believe that including non-BART boilers to set a stack limit that is supposed to represent BART-level controls for the two BART units has many problems and is unlawful. The control efficiency required of the BART units will depend on the operating characteristics of the other, non-BART units, if DNR uses a combined limit. This dilutes the stringency of the BART limits.

Moreover, as the National Park Service and the Fish and Wildlife Service commented earlier this month, DNR's calculation of emission reductions (in tons of NOx and SO2) is inflated because it relies on "baseline" emissions that are not realistic. Specifically, we note that Boiler B24 has been shut down and is no longer in the facility's permit[1] and that DNR used maximum emissions from so-called "design fuel" rather than the more representative fuels for the boilers.

We are attaching and incorporate the comments of the federal agencies herein by reference.

Furthermore, if the non-BART boilers (B24, B25 and B28) are subject to emission controls in the future, and emissions of NOx and SO2 are reduced, the combined stack BART emission limits DNR proposes would effectively allow those future emission reductions from the non-BART units to make the BART limits applicable to boilers B26 and B27 less stringent. We note, for example, that there are currently administrative actions pending before DNR and the US EPA alleging that lower emission limits apply to the facility's boilers. Those administrative actions may find that the facility triggered New Source Review or New Source Performance Standards and that the boilers are subject to lower emission limits. Additionally, the MACT standard for industrial boilers will likely result in emission reductions from boilers B25 and B28 that would effectively weaken the BART limits by requiring less pollution reduction from B26 and B27 to meet the stack limit.

We also agree with and incorporate the National Park Service's comments regarding control efficiencies achievable with the controls DNR reviewed, the erroneous assumptions about ammonium bisulfates, SO3 conversion, and DNR's double-counting of "operating variability." The appropriate SO2 removal efficiency should be no less than 95%[2] and the emission rate no greater than 0.11 lb/MMbtu. The appropriate NOx

[1] We also note that Boiler B25 was shut down for several years and if it operates again in the future, would likely be subject to New Source Review and/or NSPS. See http://www.epa.gov/region7/air/title5/petitiondb/petitions/entergy_decision1999.pdf

[2] We also do not agree with DNR's rejection of lower sulfur fuels (including natural gas), wet scrubbing, and a combination of cleaner fuels and scrubbing options. DNR's technical documents make no analysis of cleaner fuels and an insufficient analysis for wet scrubbing. Moreover, page 11 of the technical support document incorrectly asserts that in a BACT analysis, the coal sulfur content is established first and then a control efficiency is applied. Actually, in a series of decisions, EPA has made clear that a lower coal sulfur content (or a cleaner fuel than coal) has to be considered as part of the BACT analysis. The cleaner fuel, plus the scrubbing, must be combined as the "control option" being compared to other options, and the cost of the overall option (fuel switch plus scrubber) compared in $/ton—and not

emission rate should be based on the most effective control technology in Table 4.4 (RSCR or better and 84%+ removal from B26 and 94%+ removal from B27).

Compliance should also be shown through a lb/MMBtu limit and not the permit's alternative options of a lb/MMbtu or mass (tons) limit.

DNR assumes an emission rate for PM10 of 0.025 lb/MMBtu as BART, based on the control efficiency from existing controls, but does not establish that limit. Instead, it restates the existing SIP limits that are well above 0.025 lb/MMbtu and do not represent the control efficiency assumed by DNR for existing pollution controls. DNR must establish the 0.025 lb/MMBtu limit as BART.

Additionally, we agree with and incorporate herein the federal agencies' comments that DNR's modeling assumed actual emission rates for PM10, rather than allowable emission rates. DNR should either re-model with allowable emission rates or establish PM10 limits for the EGUs that reflect the emission rates that DNR modeled.

David Bender

MCGILLIVRAY WESTERBERG & BENDER LLC on behalf of Sierra Club and Midwest Environmental Defense Center

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separated as two steps. The method that DNR appears to have used inflates the cost of the fuel switching when combined with scrubbing and, further, compares the *incremental* cost effectiveness to preconceived thresholds for *average* cost effectiveness. This is improper.

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July 29, 2010

VIA ELECTRONIC AND U.S. MAIL

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Re: **Comments on Draft BART Determination for Georgia Pacific Consumer Products LP**

Ms. Crawford and Mssrs. Loftus and Karman,

These comments are submitted on behalf of Sierra Club and its thousands of members in Wisconsin. As you know, air pollution from coal combustion has been a concern of the groups and their members for decades. We appreciate this opportunity to comment on an important first step in cleaning up air pollution from the Georgia Pacific plant in Green Bay. If you have any questions about the comments below, please do not hesitate to contact us.

1) DNR Must Also Establish BACT Limits For EGUs

We recognize that when DNR started its BART review process it assumed that the Clean Air Interstate Rule ("CAIR") would apply to Electric Generating Units (EGUs) and that separate BART determinations would not be required under NR 433.04(7). However, as DNR is now aware, the CAIR was remanded to EPA by the Court of Appeals for the District of Columbia and the EPA is proposing to replace CAIR with a new program known as the "Transport Rule." See www.epa.gov/airtransport. That rule will be in place before the deadline for compliance with the BART requirements in NR 433.

The existing BART regulations for Wisconsin only exempt an EGU from BART if it is "subject to the trading programs of the clean air interstate rule under 40 CFR part 97…" Wis. Admin. Code § NR 433.04(7), 433.05(1)(e). There is no reference to a replacement for that rule—whether codified in 40 CFR part 97 or elsewhere. The rule does not exempt EGUs subject to any trading program contained in 40 CFR part 97, but only to the "clean air interstate rule." Moreover, DNR has taken the position in the past that it cannot adopt references to future EPA regulations, such as the replacement for the CAIR. Therefore, no EGU can be exempt from NR 433 and BART once EPA eliminates CAIR and replaces it with some other program.

In summary, DNR is required to adopt SO2 and NOx BART limits for BART-affected EGUs.

2) Cost of Controls

We agree with the DNR that, because states are implementing BART for the first time, there is not an established threshold for cost effective BART controls. We agree with the DNR also that past BACT determinations are informative. However, we disagree with DNR's statement that "the Department and other state regulatory agencies have required air pollution controls costing upwards of 7,000 to 10,000 $/ton for BACT." Wisconsin DNR, Best Available Retrofit Technology at Non-EGU Facilities (June 24, 2010) (hereinafter "Technical Support Document" or "TSD"). BACT determinations in the past, adjusted for inflation, are significantly higher. Moreover, the touchstone for BACT cost thresholds is what other facilities are paying for the same controls. Other large coal boilers similar to those at the Georgia Pacific plant are paying far in excess of $7-10,000 per ton for modern pollution controls.[1]

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[1] EPA once determined a $10,000/ton cost ceiling was reasonable for NOx and SO_2 in attainment areas, but that figure was in 2001-dollars. *See* expert report of Matt Haber - EPA, Best Available Control Technologies for the Baldwin Generating Station, Baldwin, Illinois, prepared for the United States in connection with *United States v. Illinois Power Company and Dynegy Midwest Generation, Inc.*, Civil Action 99-883-MJR, in the U.S. District Court for the Southern District of Illinois, April 2002, p. 17. The construction cost price index has increased from 1,093.9 in 2001 to 1,454.4 in the third quarter of 2008, which means that the cost effectiveness threshold used by EPA escalated by 33% over that time period. *See* Chemical Engineering, Marshall & Swift Equipment Cost Index – electric power industry (Nov. 2008), at 68. As a result, the cost effectiveness threshold has increased to over $13,300 per ton of pollutant removed by the third quarter of 2008 and is higher today. Even this figure is lower than the per-ton BACT cost effectiveness threshold of $17,500 for NOx, $18,300 for SO_2, and $17,500 for VOCs that the Bay Area Air Quality Management District in California uses. Bay Area Air Quality Management District, BACT

Therefore, we agree that BART cost-effectiveness is a relevant guide, but disagree with the thresholds DNR states in the TSD. Regardless, all of the pollution control options analyzed by DNR in the TSD are cost effective (including SCR for NOx control on both boilers) under even DNR's 7-10,000 $/ton range.

Moreover, if a $M/dv analysis is performed, all of the controls considered by DNR in the TSD fall within the range DNR purports to be appropriate (based on Federal Land Managers) of 16-51 $M/dv for SO2 and 7-51 $M/dv for NOx. See e.g., TSD at p. 23 ($3090 $/ton and $17.8M/dv for wet scrubbing at 98% control), 30 ($3,000/ton NOx and $16.00/dv for combined stack SCR).

Therefore, none of the controls considered in the TSD should be eliminated for cost considerations. Instead, DNR should establish BART based on the most effective controls for SO2 and NOx.[2] From the controls considered by DNR, those are SCR for NOx and a wet scrubber system for SO2.

3) Wet Scrubber Technology Is Capable of Much Greater Control at a Much Lower Cost Than Considered By DNR

In the TSD, DNR considers wet scrubber technology achieving up to 98% control (from a baseline rate of 2.29-3.99 lb SO2/MMBtu. *See* TSD pp. 18 and 23. However, certain types of advanced wet scrubbers, particularly a jet bubbling reactor or magnesium enhanced lime scrubber, can achieve 99 percent or greater SO2 removal. Yasuhiko Shimogama, *Commercial Experience of the CT-121 FGD Plant for 700 MW Shinko-Kobe Electric Power Plant*. A number of facilities have installed the Chiyoda CT-121 jet bubbling reactor. Chiyoda's bubbling jet reactor (a type of wet FGD) has consistently achieved >99% SO_2 removal during long-term operation at the Shinko-Kobe power plant in Japan. This facility consists of two 700-MW coal-fired utility boilers. The wet FGD was designed to achieve 0.014 lb SO_2/MMBtu (9 ppmv at 3% oxygen) on an instantaneous basis, which is the applicable SO2 emission limit in Japan. It has also been achieved at several coal-fired power plants in Japan and is proposed for several U.S. coal fired power plants. *Id.* Georgia Power recently contracted for the installation of four CT-121 jet bubbling reactors to be installed at Bowen Station. The Bowen units include two 750 MW units and two 950 MW units. *Id.* The jet bubbling reactor has been guaranteed by Chiyoda to achieve 99% SO_2 removal on three coal-fired boilers in Japan.[3] It also has been demonstrated

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Workbook Policy and Implementation Procedure: Introduction (Aug. 31, 2007), at 3. Additionally, Wisconsin utilities are incurring costs of $15,400 per ton of NOx removed to meet BACT emission limitations. The proposed SCR on Edgewater Generating Station unit 5 is estimated to cost that amount. Therefore, a historic $10,000/ton threshold is not the current threshold.

[2] Even if DNR had determined that some controls were eliminated from review because of cost, we question some of the assumptions made in the cost analysis. For example, the use of natural gas for reheat rather than steam coils. However, we are not providing those comments because DNR has not determined any of the controls to be outside the rage that is considered cost effective for BART.

[3] *See* CT-121 FGD Process – Jet Bubbling Reactor, http://www.bwe.dk/fgd-ct121.html.

in the U.S. at the University of Illinois's Abbott power plant and Georgia Power's Plant Yates[4] and recently was licensed for use on several additional plants in the US, including Dayton Power & Light's Killen and Stuart plants, and AEP's Big Sandy Unit 2, Conesville Unit 4, Cardinal Units 1 and 2, and Kyger Creek, among others.[5] Mitsubishi, a vendor of scrubber systems, reports it has guaranteed SO_2 removal efficiencies up to 99.8 percent, including four coal-fired boilers.[6, 7, 8]

Magnesium Enhanced Lime wet scrubbing technology also achieves SO2 control of 99%. Lewis Benson, et al., *The New Magnesium Enhanced Lime FGD Process*. Documented experience at the Mitchell Station in Pennsylvania demonstrates that magnesium enhanced lime, a type of wet scrubbing, regularly achieves 99% control of SO2.

4) Consideration of Clean Fuels

DNR does not include a robust consideration of clean fuels. The Georgia Pacific boilers were not originally designed to burn petroleum coke and only began using that fuel relatively recently. Therefore, at a minimum, in addition to end-of-the-pipe scrubber technology, Georgia Pacific's BART limits should be set based on eliminating coke use. Additionally, Georgia Pacific's proposed BART included a proposal to use lower-sulfur coal. While this was in lieu of scrubbing in Georgia Pacific's proposal, there is no reason that lower sulfur coal should not be combined with scrubbing for a greater pollution reduction than proposed in DNR's draft. The fact that Georgia Pacific proposed cleaner coal and DNR proposes a scrubber demonstrates that it is clearly feasible to burner lower sulfur coal at the boilers in combination with a scrubber.

Moreover, DNR must consider using natural gas to fire the boilers instead of coal. Natural gas has a sulfur emission factor of almost zero; resulting in a control efficiency near 100% compared to the baseline period. The guidance incorporated into the NR 433 regulations requires an analysis that begins with a top-down analysis similar to BACT. As DNR is aware, considering natural gas at a boiler that might otherwise burn coal is one of the options that must be considered in a BACT analysis. *See e.g., In re Northern Michigan University*, 14 E.A.D. __, PSD Appeal No. 08-02, Slip Op. at 20 n.17 (EAB Feb. 18, 2009). We also understand that DNR asked We Energies recently to justify not using natural gas as the basis for BACT for the

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4 Emission-control Technologies Continue to Clear the Air, Power, May/June 2002.

5 Chiyoda Licenses Its Flue Gas Desulfurization Technology in USA Newly for 5 Coal-Fired Generation Units, Press Release, May 2, 2005; Chiyoda Licenses its Flue Gas Desulfurization Process in USA for Georgia Power Owned 4 FGD Units, January 26, 2005.

6 Jonas S. Klingspor, Kiyoshi Okazoe, Tetsu Ushiku, and George Munson, High Efficiency Double Contact Flow Scrubber for the U.S. FGD Market, Paper No. 135 presented at MEGA Symposium, Air & Waste Management Association, May 19-22, 2003, p.8, Table 4.

7 Yoshio Nakayama, Tetsu Ushiku, and Takeo Shinoda, Commercial Experience and Actual-Plant-Scale Test Facility of MHI Single Tower FGD.

8 http://www.mhi.co.jp/mcec/product/fgd.htm.

proposed Domtar cogeneration plant proposed in Wausau. Therefore, it must also be considered in a BART analysis, which incorporates a BACT analysis.

DNR's record for this facility includes an analysis done by DNR of the natural gas pipeline capacity for the plant. DNR's investigation indicates that there is gas available in sufficient quantities to allow the facility to fire gas in boilers 6 and 7.

Our initial calculations, assuming $7/MMBtu natural gas prices, shows that converting boilers 6 and 7 to gas would cost $4,023/ton of SO_2 emissions avoided—based on fuel costs-- and some additional (but relatively small) costs for burner replacement or adjustments. This is well within the range of reasonable pollution control costs. Moreover, we note that in a BACT analysis, the cost of the control would be reduced by all pollutants removed. Here, fine particulates would also be reduced by a switch to natural gas. A fair analysis would include this PM-reduction benefit in addition to the SO_2 reduction benefit when considering the $/ton of pollutant reductions.

5) **DNR's proposed limits do not represent the degree of pollution control determined to be BART.**

DNR's TSD determines that BART is 95% control of SO2 from boiler 6 and 7 and 84 and 92% control of NOx from 6 and 7, respectively. *See* TSD p. 13. However, the final limits established represent something much less stringent because DNR attempts to account for the flue gas from boilers 4, 5 and 8 that exhaust through the same stack. This is not appropriate here. Boiler 4 is shut down and Boiler 5 has not operated for several years and is unlikely to operate much, if at all, in the future. DNR's own analysis of the recent operation of boilers 4-8 confirms this. The structure of the limits actually provides a perverse incentive for GP to switch steam generation to boilers 6 and 7 and then operate those boilers at a much less-stringent pollution control rate. This is contrary to the purpose of BART. Put another way, DNR's limits, which assume high emission rates for boilers 4 and 5, above what is likely to actually occur at the boilers, effectively requires much less than 95% and 84-92% control of SO_2 and NOx from boilers 6 and 7. Additionally, if boilers 4, 5 and/or 8 are subject to future control requirements (*i.e*., New Source Review, RACT, NESHAPs) and control their emissions or retire, boilers 6 and 7 will still be subject to limits that are much weaker than the emission rates DNR determined to be BART for those units.

DNR must address this problem with the proposed limits to ensure that boilers 6 and 7 are meeting BART-level emission reductions during all operating scenarios, regardless of whether other boilers in the plant are operating. This can be done in any one of at least three ways:

1. Requiring installation of CEMS in the flue ducts(s) after boilers 6 and 7 but before gas streams are combined with other boilers.

2. Requiring emission limits for the entire stack that represent BART-level control for boilers 6 and 7 (i.e., using DNR's draft BART, 0.11-0.20 lb/MMBtu for SO2 and 0.07-0.10 lb/MMBtu for NOx). This might require control of emission streams from boilers 4, 5 and 8 if those boilers are running. However, such control is merely a co-benefit from Georgia Pacific's decision to vent all boilers through the same stack instead of construction a new stack. It is entirely consistent with BART to set a limit that ensures that 6 and 7 are controlled to BART by setting a limit for the stack to which those boiler vent and leaving the choice to Georgia Pacific whether to build a new stack and segregate boilers 4, 5 and 8, or to controls those units too.

3. Express the limit as a weighted average so that boilers 6 and 7 are always achieving the emission rates that represent BART for those units. For example, DNR calculates emission limits under the NOx RACT rule in NR 428.25 based on a weighted average for multiple units by multiplying each unit's heat input for the relevant time period by the emission limit for that unit. Here, DNR could set a 30-day rolling limit for the Georgia Pacific shared stack based on RACT for boilers 6 and 7 in lb/MMBtu multiplied by the heat input for those units and the historic emission rates for 4, 5 and 8 multiplied by the heat input for those boilers.[9] Compliance with this weighted average limit would be ensured by CEMS.

As DNR notes, BART is a "continuous control requirement." TSD at p. 20. The level of BART for boilers 6 and 7 does not (and should not) depend on whether other boilers are operating at the same time. Therefore, the DNR must change the way that it expresses the limits for the combined stack to ensure that boilers 6 and 7 continuously meet the emission rates that DNR determines is BART for those boilers.

6) DNR has not shown that the proposed limits will protect air quality.

In the TSD, DNR states that it "finds" that the facility will meet applicable "emission limits and other requirements" and will not "cause or exacerbate a violation of an ambient air quality standard or ambient air increment." TSD at p. 12. It is not clear where DNR made this analysis. The information we have available indicates that DNR has done no analysis recently and the last analysis done by DNR was deficient in the following ways.

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[9] A better option would be to express the limits as lbs per ton of steam production, to ensure that emissions do not increase due to losses in boiler efficiency over time.

A. DNR Has Not Ensured Compliance With Increments By Analyzing All Increment Consuming Emissions at the Plant.

DNR issued GP a permit in 2004 allowing: (1) an increase in the size of paper machine 9; and (2) an increase in the size of an on-site turbine generator used to generate electricity. See Preliminary Determination for 03-DCF-327; Preliminary Determination for 03-DCF-327-R1. DNR has agreed that these changes to the facility debottlenecked the boilers at the facility. See e.g., Memorandum from Don C. Faith III to File, (October 7, 2004) ("The revision request is to include the addition of a replacement steam turbine (for electricity generation) to replace an existing turbine and incorporate this as a part of the recently issued construction permit. Though larger capacity than the existing unit, it will not increase the steam demand beyond what was already accounted for within the review for the paper machine #9 modification process (which also debottlenecks the boilers).").

The emission increases from the debottlenecked boilers are increases resulting from a major modification to the plant. While EPA has noted in guidance that BACT limits are not required for emission units that do not undergo a change in method of operation or physical change as part of the project,[10] the emission increases from those emission units attributable to the project nevertheless consume increment. However, it appears that the increment analysis for 03-DCF-327 and the current draft permit (405032870-P10) do not consider the emissions from the boilers to be increment consuming. See Preliminary Determination for 03-DCF-327 at 44-45, Table 2 ("GP Fort James GRB West Paper Mill Increment Consuming Emission Rates") (not listing stacks S08-S11, which vent emissions from the boilers, as consuming increment).

Because all of the boilers increased emissions, as that term is used for purposes of the PSD program, their emission increases (potential to emit less baseline actual) consume increment. *See e.g.*, Preliminary Determination for 03-DCF-327 at 51-56. The table on page 53 of the Preliminary Determination appears to calculate emission increases from all affected emission sources attributable to the modification, including the boilers under "Affected Sources":

[10] We disagree with this interpretation in U.S. EPA guidance, but the issue of BACT applicability is not at issue in these comments.

	Emission Increases (tons per year)									
	PM	PM_{10}	NO_x	SO_2	CO	VOC	Pb	Hg	HF	H_2SO_4
No. 9 Paper Machine (a)										
I. Future Potential Emissions	18.01	18.01	27.34	58.23	22.07	189.55	0.0017	0.00057	---	---
II. Past Actual Emissions	5.45	5.45	9.6	0.058	8.07	26.49	0.000048	0.00005	---	---
III. Emissions Increase	12.56	12.56	17.74	58.17	14	163.06	0.00165	0.00052	---	---
Affected Sources										
IV. Future Potential Emissions	1931.94	1931.58	7368.8	33415.9	2051.7	484.48	1.44	0.23	62.5	483.47
V. Past Actual Emissions	559.71	468.43	4253.82	13627.7	801.48	114.64	0.10952	0.0463	34.62	243.57
VI. Emissions Increase	1372.2	1463.15	3114.98	19788.2	1250.2	369.84	1.33	0.18	27.88	239.9
Sum of No. 9 Paper Machine and Affected Sources (b)										
VII. Future Potential Emissions	1949.95	1949.59	7396.14	33474.1	2073.77	674.03	1.44	0.23	62.5	483.47
VIII. Past Actual Emissions	565.16	473.88	4263.4	13627.8	809.55	141.13	0.1096	0.0463	34.62	243.574
IX. Emissions Increase	1384.8	1475.71	3132.7	19846.3	1264.22	532.9	1.33	0.18	27.88	239.9

However, DNR has not included the boilers as increment consuming emission sources when modeling for increment compliance. Note that the Preliminary Determination for 05-DCF-058 lists the following emission rates as having been modeled for increment:

TABLE 2 GP Fort James GRB West Paper Mill Increment Consuming Emission Rates				
ID	PM RATE (#/HR)	SO_2 RATE (#/HR)	NO_x RATE (#/HR)	CO RATE (#/HR)
S08	14.900	9.0000	22.9000	2.9397
S10C	-	7280.00	1421.30	223.30
S10P	-	-1998.40	-464.80	-
S11	24.300	340.20	238.100	70.300
S12	5.600	0.0160	3.500	-

In a phone call on March 31, 2010 with John Roth of DNR, he stated that it is his position and the DNR's position that none of the sources exhausting to S10 (i.e., the boilers 5-8) consume increment. Specifically, he asserts that even though the boilers increased emissions, for purposes of PSD applicability, as part of the project described in 03-DCF-327, that none of the boilers' emissions consume increment because none increased maximum hourly emission rates. This is not a correct interpretation of law.

The Clean Air Act provides that a PSD source cannot "cause, or contribute to, air pollution in excess of any… maximum allowable increase…" 42 U.S.C. § 7475(a)(3). Specifically, the owner cannot cause or contribute to a violation of any "maximum allowable increase over the baseline concentration in any area." Wis. Admin. Code § NR 405.09; see also 40 C.F.R. § 52.21(k). For purposes of this analysis, it is necessary to determine what emissions are in the baseline concentration and which emissions are excluded from the baseline and therefore, necessarily increment consuming. Wis. Admin. Code § NR 405.02(4); 40 C.F.R. § 52.21(b)(13)(ii).

The applicable regulations provide:

> The following will not be included in the baseline concentration and will affect the applicable maximum allowable increase(s)…

> *Actual emissions, as defined in paragraph (b)(21)* of this section, from any major stationary source on which construction commenced after the major source baseline date…

40 C.F.R. § 52.21(b)(13)(ii), (ii)(a) (emphasis added); Wis. Admin. Code § NR 405.02(4)(b) (same). The definition of "actual emissions, as defined in paragraph (b)(21)" is "… the average rate, in tons per year, at which the unit actually emitted the pollutant during a consecutive 24-month period which precedes the particular date and which is representative of normal source operation…" 40 C.F.R. § 52.21(b)(21)(ii); see also Wis. Admin. Code § NR 405.02(1)(a). Alternatively, "actual emissions" for a source that has not commenced normal operation can be the potential to emit, Wis. Admin. Code § NR 405.02(1)(c), or DNR can presume the actual emissions to be the "allowable emissions." 40 C.F.R. § 52.21(b)(2)(iii); Wis. Admin. Code § NR 405.02(1)(b). These are the only definitions of "actual emissions" under § 52.21(b)(21) or Wis. Admin. Code § NR 405.02 that could apply.

By its plain language, the actual emissions from the entire Georgia Pacific "major stationary source" are to be excluded from the baseline and should be increment consuming because the plant "commenced construction" when it underwent a major modification associated with 03-DCF-327. Wis. Admin. Code § NR 405.02(4)(b)1.; *see also* § 405.02(11) (construction includes modification). There is no textual basis for separating this by individual emission units nor by emission increases attributable to a major modification. Rather, the applicable regulations' plain language says to exclude the "actual emissions"—as defined in the regulations—from the "major stationary source" from baseline and count them as consuming increment.

Even if this language could reasonably be interpreted to mean that only the increased emissions <u>attributable to a major modification</u> are excluded from baseline and increment consuming, rather than the "actual emissions" from the "major stationary source" as the regulations state, DNRs analysis would not meet this interpretation either.[11] As noted above, when issuing the permit for the major modification associated with 03-DCF-327, DNR determined that emissions from the boilers would increase. Yet, DNR has not excluded those increased emissions from the baseline concentration and considered them increment consuming as required by 40 C.F.R. § 52.21(b)(13)(ii) and Wis. Admin. Code § NR 405.02(4)(b). *See e.g., In re Northern Michigan University*, PSD 08-02 Slip Op. at 47 (EAB Feb. 18, 2009) (instructing the agency to calculate

[11] We note that the EPA's Environmental Appeals Board has provided this interpretation. *See In re Northern Michigan University*, 14 E.A.D. __, PSD 08-02 Slip Op. at 46 (EAB Feb. 18, 2009) ("one could reasonably construe the statutory, regulatory, and preamble language to mean that *all actual emissions from the modifications to a source* consume increment… the emissions in equation could be specifically tied back to the modifications, and only those emissions would be considered increment consuming." (emphasis original).) We respectfully disagree with the EAB on this point and contend that there is no reasonable interpretation of the language Congress and EPA actually used that can support this interpretation. The regulation does not speak in terms of increases, but explicitly adopts the definition of "actual emissions." Moreover, the regulation does not say emissions (or increases) from the "construction" or the "major modification," consume increment, but state that emissions from the stationary source consume increment.

increment consuming emissions from a source that underwent a major modification based on the "actual emissions" defined in 40 C.F.R. § 52.21(b)(13)(ii), (21) and part 51 Appx. W § 8.1.2.i & Table 8-2 and 45 Fed. Reg. at 52,717-19, and NSR Manual at C.10-.11, .35-.36, .44-.50). Instead, DNR's analysis of increment compliance presumes that no major modification every occurred. This is inconsistent with the regulations and statutes.

DNR must consider the emissions from the boilers affected by the major modification associated with 03-DCF-327 as increment consuming.

B. DNR Has Not Modeled Compliance With 1-Hour NO2 (NOx), SO2, or 24-hour and annual PM2.5 NAAQS

Before issuing any operating permit, including a revised permit, the DNR must ensure that emissions from the facility will not "will not cause or exacerbate a violation of any ambient air quality standard…" Wis. Stat. § 285.63(1)(b); *see also* Wis. Admin. Code § NR 428.03 ("No person may cause, allow or permit nitrogen oxides or nitrogen compounds to be emitted to the ambient air which substantially contribute to the exceeding of an air standard or cause air pollution."). EPA has recently updated the ambient air quality standards for Nitrogen Oxides (NOx) by adding a one-hour maximum of 100 ppb. 75 Fed. Reg. 6475 (Feb. 10, 2010). EPA has also updated the SO2 standard to include a one-hour maximum of 75 ppb. DNR has not ensured compliance with these standards. DNR must do so before issuing the final permit. Wis. Stat. § 285.63(1)(b); see also Wis. Admin. Code § NR 417.03 ("No person may cause, allow or permit emission of sulfur or sulfur compounds into the ambient air which substantially contribute to the exceeding of an air standard or cause air pollution.").

The new 1-hour NO_2 and SO_2 standards are necessary to protect public health, especially that of the elderly and children, from the harms of short-term exposure to elevated levels of pollution. As such, the standards will help reduce respiratory-related emergency room visits and hospital admissions.[12] U.S. EPA issued the 1-hour standards because a short-term NAAQS is required to protect public health above and beyond the existing annual standard.[13] Demonstrating protection of only the annual NO_2 standard and 3 and 24-hour SO2 standards are insufficient to comply with applicable regulations and to protect public health.

Moreover, on July 18, 1997, EPA revised the NAAQS for particulate matter to add new annual and 24-hour standards for fine particles using PM2.5 as the indicator. EPA revised the 24-hour NAAQS for PM2.5 on September 21 , 2006, reducing the standard from 65 ug/m3 to 35 ug/m3. EPA has recently stated in the *Federal Register* at 75 FR 6827 that previous technical difficulties which necessitated using PM10 as a surrogate for PM2.5 have been largely resolved. Moreover, Wisconsin has adopted PM2.5 standards into state law as well. See Wis. Admin.

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[12] *See* U.S. EPA, Fact Sheet: Final Revisions to the National Ambient Air Quality Standards for Nitrogen Dioxide, available at http://www.epa.gov/air/nitrogenoxides/pdfs/20100122fs.pdf

[13] *See* generally 75 Fed. Reg 6,474.

Code § NR 404.04(9). Pursuant to Wis. Stat. § 285.63(1)(b), DNR may not issue an operating permit unless DNR has determined that emissions from the facility "will not cause or exacerbate a violation of any ambient air quality standard…" It does not appear that DNR has done so for the Georgia Pacific plant. If it has, it has not made that analysis part of the permit record available to the public for comment. DNR must model PM2.5 impacts from the facility to ensure that ambient air standards are protect before issuing the permit.

7) DNR must clarify the sequence of permits for Georgia Pacific.

We note that DNR is proposing to incorporate the proposed to incorporate the BART limits into a revision to permit 405032870-P01 (as revision P03). However the permit DNR is proposing to "revise" expired years ago and is not longer capable of being revised. DNR has noticed a renewal permit for public comments many months ago and Sierra Club submitted comments. (Actually, DNR has noticed the renewal multiple times and Sierra Club commented multiple times.) DNR has yet to issue that renewal permit. To the extent that DNR combines its actions, we reiterate and incorporate by reference Sierra Club's prior comments on the proposed draft renewal permit herein. DNR should clarify what permits are being renewed and revised so the public knows what permits are in effect and so parties can exercise their rights to appeal.

Sincerely,

MCGILLIVRAY, WESTERBERG & BENDER LLC

David Bender

Attorneys for Sierra Club

United States Department of the Interior
NATIONAL PARK SERVICE
Air Resources Division
P.O. Box 25287
Denver, CO 80225

TAKE PRIDE IN AMERICA

IN REPLY REFER TO:

N3615 (2350)

September 2, 2011

Bill Baumann, Acting Chief
Bureau of Air
Wisconsin Department of Natural Resources
101 South Webster Street
Madison, Wisconsin 53707-7921

Dear Mr. Bauman:

On July 1, 2011, we received Wisconsin's revised draft Regional Haze State Implementation Plan. The National Park Service, in consultation with the U.S. Fish and Wildlife Service, has reviewed the revised draft. The Department of Natural Resources (DNR) has addressed some of our comments on the previous draft SIP. However, we are concerned that DNR has weakened the BART determination for Georgia Pacific in the revised SIP. Our technical comments are enclosed.

We appreciate the opportunity to work closely with the State of Wisconsin to improve visibility in our Class I areas. For further information regarding our comments, you can contact Don Shepherd of my staff at (303) 969-2075.

Sincerely,

Patricia Brewer for

Carol McCoy
Chief, Air Resources Division

Enclosures

cc:
John Summerhays
U.S. EPA Region 5
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Chicago, IL 60604

Jonathan Loftus
Bureau of Air Management
Wisconsin Department of Natural Resources
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Todd Hawes
U.S. EPA OAQPS
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Research Triangle Park, NC 27711

National Park Service Comments
Wisconsin Revised Draft Regional Haze State Implementation Plan
September 2, 2011

The National Park Service, in consultation with the U. S. Fish and Wildlife Service, has reviewed Wisconsin Department of Natural Resources (WDNR)'s revised draft regional haze state implementation plan (SIP) dated July 1, 2011. Our comments below focus on WDNR's analyses of Best Available Retrofit Technology for Georgia Pacific and of reasonable progress in visibility improvement at Northern Class I areas. We also support comments provided to WDNR by the U.S. Forest Service.

Cross State Air Pollution Rule

WDNR is relying on federal rules (initially the Clean Air Interstate Rule (CAIR), now replaced by the Cross State Air Pollution Rule, CSAPR) for reductions of sulfur dioxide (SO_2) and nitrogen oxide (NO_x) emissions from Electric Generating Units (EGU) in the state. The visibility modeling provided by the Midwest Regional Planning Organization (MRPO) used 2018 "on-the-books" projections for EGU controls under CAIR. We commend WDNR for also providing a range of 2018 EGU control assumptions for comparison with the original MRPO modeling results.

BART for EGU Sources

All Wisconsin EGU subject to BART are now subject to CSAPR. WDNR expects that the Environmental Protection Agency (EPA) will determine that SO_2 and NO_x reductions under CSAPR are better than would be accomplished by source-specific BART requirements. We are concerned that while CSAPR may result in greater regional emissions reductions than cumulative source-specific BART requirements, specific Class I areas, such as the Northern Class I areas, may not be as well protected as would be the case under source by source BART. We, like WDNR, are awaiting EPA's analysis.

WDNR is proposing that the existing PM control equipment (electrostatic precipitator or baghouse) and permit limitations are satisfactory for BART. However, as noted in our March 6, 2011 comments to WDNR, the analysis used by WDNR modeled current actual emissions instead of the proposed permit limits, which, in some cases, are more than an order of magnitude greater than the emissions modeled.

The WDNR modeling exercise demonstrates that elimination of the modeled emissions would have no significant visibility benefit. However, WDNR must show that the proposed BART limits for PM_{10} have no significant impact on visibility to successfully demonstrate that a full five-factor BART analysis is unnecessary. Or, WDNR could propose BART limits that reflect the true capabilities of the existing control technologies.

BART Determination for Georgia Pacific

WDNR determined that Georgia Pacific (GP) in Green Bay is the only industrial source subject to BART in Wisconsin. The National Park Service is disappointed in the revisions made to the GP BART determination. We do not agree with WDNR's reported emissions reductions at GP (7,098 tons/year SO_2 and 2,509 tons/year NO_x) because the changes made to the baseline emissions and control efficiencies appear to lead to paper reductions greater than actual emissions reductions.

We recommend that WDNR return to the fundamental, underlying concepts inherent in the Regional Haze Program--the goal is to reduce visibility impairment in Class I areas by applying reasonable emission reduction methods in an expeditious manner.

WDNR has revised the baseline emissions for GP. The BART-subject boilers at GP are B-26 and B-27. It appears that WDNR has assumed that boilers which have been shut down would be brought back on line, and that coal sulfur content would increase substantially. Because WDNR has provided no real-world evidence to support these assumptions, and because the aim of the BART process is to reduce emissions—not to maximize future potential emission limits— we disagree with this approach. Boilers that have been shut down should not be included in the baseline, nor should higher sulfur coal be postulated for the future case. Both of these approaches are contrary to the strategy of reducing emissions. Finally, all analyses of the amount of emissions reduced and the associated costs should be based upon valid baseline emissions.[1]

WDNR has made several incorrect assumptions regarding baseline emissions:

- WDNR has included boilers B24, B25, and B28 in its BART analysis. These boilers are not BART-eligible and cannot be used to mitigate more-stringent BART requirements on boilers B26 and B27 which are BART-eligible.
- Boiler B24 ceased operation in 2004 and could be subject to New Source Review requirements if it were to resume operation. Emissions from boiler B24 cannot be included in this BART analysis.
- Boiler B25 ceased operation in 2008 and could be subject to New Source Review requirements if it were to resume operation. Emissions from boiler B25 cannot be included in this BART analysis.
- WDNR cannot assume that GP would switch to higher-sulfur fuels in the absence of supporting evidence. On the contrary, in its March 2009 BART analysis, GP evaluated switching to **lower-sulfur** fuels as a technically-feasible option. The BART program encourages switching to cleaner fuels, not maximizing future potential emissions.[2]

Instead, WDNR should assume for baseline estimation purposes that GP will continue to burn its current fuels at its current rate in the boilers it currently uses, unless GP provides strong evidence and commitment to modifying its current method of operation.

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[1] If WDNR is to base an emission limit upon an assumption that each boiler will always operate at its historic maximum rate, then it must conduct its five-step BART analysis upon that basis.

[2] We note that WDNR expressed concern that certain pollution control technologies might increase CO_2 emissions. However, by allowing continued use of petroleum coke, WDNR appears to have ignored GP's statement that "An additional difference between the fuels is the estimated CO_2 emissions. CO_2 Emissions from petroleum coke combustion is approximately 10 to 15% above coal combustion (on a lb/mmBtu basis)."

As we discuss below, WDNR should have instead included GP boilers B24, B25, and B28 in its Reasonable Progress analysis.

Control Effectiveness

We commend WDNR for the breadth of its review of potential control technologies for SO_2 and NO_X, but we remain concerned about how the effectiveness of some of those technologies was estimated.

WDNR improperly lumped all dry-scrubbing technologies together in its proposal of 93% efficiency for SO_2 controls. Instead, WDNR should have focused upon the specific control technology, Turbosorp, it evaluated for GP. Had it done so, the data cited by WDNR for the two facilities and SO_2 concentrations most similar to GP, Greenridge and Deerhaven, clearly show that the Turbosorp scrubber can achieve 0.11 – 0.13 lb SO_2/mmBtu,[3] which, in these cases, is equivalent to 95% - 97% control. This should be the basis for a SO_2 control effectiveness estimate at GP. Instead, WDNR is proposing an SO_2 limit that is equivalent to 0.23 – 0.27 lb/mmBtu.[4] WDNR cites "operating variability" as its reason for downgrading the effectiveness of the scrubber, but its own data show that such "operating variability" was already taken into account in its evaluation of the Greenridge Turbosorp scrubber. Not only has WDNR double-counted this "operating variability" at GP, it has also exaggerated it compared to Greenridge.

WDNR raises a concern that SO_2 BART for GP at a default flue gas concentration of 1.0 lbs/mmBtu will generate a visible plume and that would create concern for overall technical feasibility of applying the Regenerative Selective Catalytic Reduction (RSCR) under these conditions. According to WDNR notes from its conversation with Babcock Power, "the typical conversion of SO_2 to SO_3 over the Selective Catalytic Reduction (SCR) catalyst in the RSCR is well less than 1%," which is typical of most SCR catalysts. The potential for an SO_3 plume can be essentially eliminated by a return by WDNR to its original more-stringent SO_2 BART determination. This issue can be further mitigated by WDNR addressing SO_2 emissions from the non-BART boilers under its Reasonable Progress requirements.

WDNR also raises concern about the formation of ammonium bisulfates in the RSCR and downstream flue duct system that would increase maintenance and operating costs throughout the system. The potential for deposition of ammonium bisulfates can be essentially eliminated by a return by WDNR to its original more-stringent SO_2 BART determination. This issue can be further mitigated by WDNR addressing SO_2 emissions from the non-BART boilers under its Reasonable Progress requirements.

Evaluate Impacts and Document the Results

WDNR determined that all five NOx control strategies for Boiler B26 and B27 are cost-effective.

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[3] Because SO_2 control efficiency is heavily influenced by inlet SO_2 concentration, in controlling SO_2, the control efficiency is less important than the ultimate outlet SO_2 concentration, as this is primarily a function of chemical equilibrium conditions and the mass transfer capability of the scrubber.

[4] Table 2.1 of the WDNR GP BART analysis document.

Evaluate Visibility Impacts

WDNR 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. We are concerned that WDNR may not have modeled its "adjusted baseline emissions." (Although we disagree with the adjustment process as discussed above, for internal consistency, once WDNR decided to use that approach, it should have based all of its analyses upon those adjusted emissions.) Had it done so, it is likely that baseline impacts, emission reductions, and visibility improvements would have been greater than presented by WDNR.

WDNR presented the total maximum visibility impact that represents the sum of the maximum modeled impacts for each of the four northern Class I areas. We commend WDNR for considering cumulative visibility impacts and benefits.

Sulfur Dioxide (SO_2) BART Determination

WDNR compared wet flue gas desulfurization (FGD) and dry circulating fluidized bed (CFB) FGD in preparing the draft BART determination. The Department maintains, under this amended BART determination, that dry CFB FGD at 93% control efficiency represents SO_2 BART for boilers B26 and B27. As discussed above, we believe that WDNR has improperly applied multiple layers of safety margins in deterring that the Turbosorp scrubber could achieve only 0.23 – 0.27 lb/mmBtu (93% control) as compared to the demonstrated capability of this technology to achieve 0.11 – 0.13 lb/mmBtu at similar facilities burning similar fuels.

Nitrogen Oxide (NO_X) BART Determination

WDNR proposed 84% and 94% control efficiency of NO_X 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 RSCR unit operating on the common flue stack at 75% to 80% efficiency. In the amended NO_X BART, WDNR maintains RSCR for boiler B27 at 70% control efficiency. With the combustion modifications and RSCR, WDNR proposes that the NO_X BART compliance control efficiency for boiler B27 is 84% reduction.

For boiler B26, WDNR has determined that RSCR control is not applicable under BART and amended the NO_x BART to 68% control based on combustion modifications and selective non-catalytic reduction (SNCR).

We remind WDNR that BART is not necessarily the most cost-effective solution. WDNR has stated that all of the NO_X control technologies presented in its Table 4.4 are cost-effective, and yet it has chosen the third-ranked technology, OFA/FGR/SNCR at 68% control efficiency, as BART. In rejecting RSCR, WDNR cites an "energy penalty" and increased CO_2 emissions. However, the "energy penalty" is already accounted for in the cost analysis and is a legitimate concern only if there is a scarcity of available energy to operate the system—which no one has suggested. And, if WDNR is sincerely concerned about CO_2 emissions, it would prohibit the combustion of petroleum coke.

Instead, based solely upon WDNR estimates in its Table 4.4, and in consideration of incremental costs, we recommend that OFA/FGR/RSCR be determined to represent BART for boiler B26 because it achieves the greatest emission reduction (81%) with cost-effectiveness of $3,675/ton and $15.6 million/dv at the most-impacted Class I area (Seney). Based upon our review of BART determination across the nation, these cost-effectiveness values are very reasonable.

Particulate Matter (PM) BART Determination
WDNR determined that the existing PM controls and permit limitations constitute BART PM requirements for boilers B26 and B27. However, the WDNR modeling exercise only demonstrates that elimination of the modeled emissions[5] would have no significant visibility benefit. Instead, WDNR must show that the proposed 0.30 lb/mmBtu BART limit for PM_{10} has no significant impact on visibility in order to successfully demonstrate that a full five-factor BART analysis is unnecessary. Or, WDNR could propose BART limits that reflect the true capabilities of the existing control technologies.

BART emission limitations
WDNR proposed two forms of emissions limits for each boiler and each pollutant SO_2 and NO_X: 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. We disagree with this proposal. Emission limits must reflect the best level of control all of the time, and should not allow the source to mix-and-match to find the least-stringent combination for each situation. Also, a mass cap limit would allow a very high lb/mmBtu emission rate during periods of low utilization.

<u>Reasonable Progress Goals (RPG)</u>

In setting reasonable progress goals, the Regional Haze Rule requires states to consider four factors for any potentially affected sources and include a demonstration how these factors were considered in setting the goal.[6] This analysis is required independent of the projected visibility improvement by 2018.

WDNR determined that RPG is met for the Boundary Waters and Voyageurs northern class I areas based on MRPO visibility modeling of the "on-the-books" 2018 emissions inventory. However, the WDNR statement is contrary to the finding by Minnesota in its Regional Haze SIP[7] that, for Boundary Waters and Voyageurs, "The RPG provides for less annual progress towards the ultimate visibility goals than the uniform rate of progress (URP)." MN goes on to estimate that natural condition will not be achieved in Boundary Water until 2093 and in Voyageurs until 2177.

MRPO visibility modeling projects that Isle Royale and Seney will not meet the uniform rate of progress by 2018.

In our March 10, 2011 comments we suggested to WDNR that:

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[5] PM controls are operated at a very high level achieving 0.025 lbs/mmBtu emission rates.
[6] 40 CFR Part 51.308 (d)(1)(i)
[7] Table 10.7: Reasonable Progress Goals for Class I areas

"WDNR has not included the required reasonable progress four factor analysis to evaluate what additional emission reductions are feasible and reasonable. WDNR needs to evaluate its emission sources and demonstrate that the State is making reasonable progress in reducing anthropogenic emissions. WDNR cites the four factor analysis prepared for MRPO by the contractor EC/R[8] for possible further controls on EGU, but does not cite the controls analyzed for industrial sectors by EC/R. This analysis should be completed for the major industrial source sectors represented in Wisconsin."

WDNR has added an analysis of emissions (Q) divided by distance (d) for the top 30 sources affecting visibility in each of the Northern Class I areas. Since the "on-the-books" 2018 inventory was used in this Q/d analysis, WDNR indicated additional control levels for some of these sources and concluded that these emissions reductions will reduce the visibility impact for both Seney and Isle Royale.

It is not clear how WDNR used the Q/d analysis. While we commend WDNR for the emissions reductions shown in its Tables 8A and 8B, we see no criterion by which WDNR determined which sources to evaluate under the Reasonable Progress four-factor approach. For example, we note that in Table 1 of its June 24, 2010 "Best Available Retrofit Technology at Non-EGU Facilities" report, WDNR showed that several facilities[9] that were exempted from BART had impacts on visibility that warrant further attention. And, Georgia Pacific, the only non-EGU subject to BART, also has large emission units that, while not BART-eligible, still have considerable visibility impacts. WDNR should justify its decision to exempt these sources from a Reasonable Progress analysis, especially considering the projections that the URP glide path will not be achieved at any of the northern Class I areas, and that, based upon WDNR's Table 1, Wisconsin is the second-largest contributing state to visibility impairment in the northern Class I areas.

We do not agree with WDNR that non-EGU controls cannot be implemented before 2018. There is significant uncertainty in the timing of future federal rules that could impact the non-EGU sectors. WDNR should evaluate all four factors for all the BART-eligible sources, the non-BART sources at Georgia Pacific, and the sources listed in Tables 8A and 8B.

In the Emissions Inventory Section (p18), WDNR reports that non-EGU SO_2 and NO_x emissions are 18,358 and 3,283 tons greater, respectively, than modeled in the "on-the-books" MRPO visibility modeling. This is due to earlier projected BART controls for non-EGU that were not implemented and is further evidence that additional reductions for non-EGU sources should be considered as part of the reasonable progress analysis.

Interstate Contributions

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[8] http://www.ladco.org/reports/rpo/consultation/products/reasonable_progress_for_class_i_areas_in_the_northern_midwest-factor_analysis_draft_final_technical_memo_july_18_2007.pdf

[9] WIS DOA/UW Madison-Charter Dt., Proctor & Gamble Paper Production Company, Thilmany paper, Packing Corporation of America-Tomahawk, Wausau Paper Corp-Mosinee, New Page – WI Rapids Pulp Mill, and Domtar A. W. Corp – Nakoosa.

WDNR asserts that "the rate of emission reduction projected for Wisconsin sources compared to Michigan and Minnesota shows that Wisconsin is meeting its share of visibility improvement." However, inspection of Figures 6 and 7 finds that, while Wisconsin is predicting greater reductions in NO_X than MI and MN, it falls short of the SO_2 reductions estimated in MN.

On September 19, 2007, the State of Minnesota sent Wisconsin a letter asking for specific emission reductions:

> "In particular, Minnesota asks Iowa, Missouri, North Dakota, and Wisconsin to evaluate further reductions of SO_2 from electric generating units (EGU) in order to reduce SO_2 emissions by 2018 to a rate that is more comparable to the rate projected in 2018 for Minnesota, approximately 0.25 lbs/MMBtu. Minnesota believes that Illinois is already in the process of meeting this goal. Emission reductions in Wisconsin are particularly important, as Wisconsin is the highest contributor outside Minnesota to visibility impairment in Minnesota's Class I areas."

From page 36-37 of the SIP:

> "In 2009, EGU SO_2 emission rates in Wisconsin were 0.47 lbs/mmBtu. A simple projection for 2018 SO_2 emission rate from EGUs can be calculated using the 2014 Clean Air Transport Rule (CATR) allocations (71,514 tons SO_2) and 2009 heat input (441 billion Btu's) grown by 1%, to results in an SO_2 emission rate of 0.29 lbs/mmBtu. This estimate is conservative as old facilities are being committed to retirement and it does not account for replacing capacity with the new Elm Road facility (1200 MW). On this basis the Wisconsin average electric utility emission rate will significantly decrease by 2014. In addition, due to EPA's committed second phase of CATR the EGU emission rate will decrease further. Therefore, the overall goal of reducing the EGU emission rate in response to the Minnesota ask is met."

We recognize that the recent promulgation of the CSAPR makes it difficult to determine if these estimates are still valid, and suggest that WDNR update its estimates accordingly. Nevertheless, it is not sufficient for WDNR to assume that, because it believes it has underestimated emission reductions, it can assume that it is making reasonable progress in spite of its analyses that show otherwise.

United States Department of Agriculture
Forest Service
Superior National Forest
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Duluth, MN 55808-1122
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File Code: 2580
Date: July 27, 2011

Mr. William Baumann
Acting Director, Bureau of Air Management
Wisconsin Department of Natural Resources
101 S. Webster Street
Box 7921
Madison, WI 53707-7921

Dear Mr. Baumann:

On January 13, 2011, the State of Wisconsin submitted a draft implementation plan describing your proposal to improve air quality regional haze impacts at mandatory Class I areas across your region. We commented on that plan in a letter to Jonathon Loftus dated March 4, 2011. On July 1, 2011, we received a modified draft plan which included major revisions to the Best Available Retrofit Technology (BART) determination for the Georgia Pacific Broadway Mill in Green Bay. This letter contains our review of this plan. Cooperative efforts such as these ensure that together we will continue to make progress toward the Clean Air Act's goal of natural visibility conditions at our Class I wilderness areas and parks.

We appreciate the changes you made in the first draft to address some of our comments. Nonetheless we continue to have a number of concerns with the current draft plan and have attached technical comments to this letter that discuss them in detail. We look forward to your response to our comments as required by 40 CFR 51.308(i)(3). For further information, please contact Eastern Region Air Resource Specialist Trent Wickman at (218) 626-4372.

Again, we appreciate the opportunity to work closely with the State of Wisconsin. The Forest Service compliments you on your hard work and dedication to significant improvement in our nation's air quality values and visibility.

Sincerely,

/s/ James W. Sanders
JAMES W. SANDERS
Forest Supervisor

Enclosure

cc: Jonathon Loftus
Pat Brewer
Don Shepherd
Tim Allen

John Summerhays
Charles E Sams
Paul Strong
Dale Higgins
Bret A Anderson

USDA Forest Service Technical Comments on the
Regional Haze State Implementation Plan (RH SIP) for Wisconsin

We appreciate the significant resources devoted by the State of Wisconsin (WI) in developing their RH SIP and responding to some of our comments made on the first draft. The projected emissions reductions in the RH SIP are an important first step toward improving visibility and other air quality related values at the affected Federal Class I areas. We have some concerns with the lack of technical analysis and some of the conclusions made in the RH SIP. These concerns are outlined below.

General Comments

1. On page 7 Wisconsin appears to believe that if it did not significantly contribute to visibility impairment in a Class I area it would not be subject to the Regional Haze Rule. Wisconsin is subject to the Regional Haze Rule either way, see 40 CFR 51.300(b)(3).

2. On page 11 it is stated "Natural conditions are defined as the level of visibility seen for the least impaired days." This definition of natural conditions is not accurate, they were estimated from the distributions of pollutants measured during the baseline scaled to estimates of annual average natural conditions made by Trijonis[1].

Best Available Retrofit Technology (BART)

3. Page 18 discusses the 2018 "on the books" emission inventory which included estimated BART controls for five non-electrical generating units (EGUs) in Wisconsin. Please include what controls were specified for these units and at what control efficiency.

4. Page 19 concludes that "Accounting for the lower EGU emissions projected in Case B (Table 4) – along with the higher projected non-EGU emissions – is expected to produce more beneficial visibility results than on-the-books controls alone modeled in Case A" We find this conclusion hard to accept without modeling to support it. Emission reductions at sources close to Class I areas were traded for statewide reductions. As you know, the impact of each ton of emissions close to the Class I Areas is higher than those further away.

5. We strongly support Wisconsin's previous determination of BART for the boilers at the Georgia Pacific (GP) plant in Green Bay. We believe the previous determination is well supported by the technical documentation prepared and submitted for our review and as part of the permitting process. The new proposal will result in approximately 3228 less tons of sulfur dioxide (SO_2) and 366 less tons of nitrogen oxides (NOx) removed. The following are components of Wisconsin's determination that should be changed:

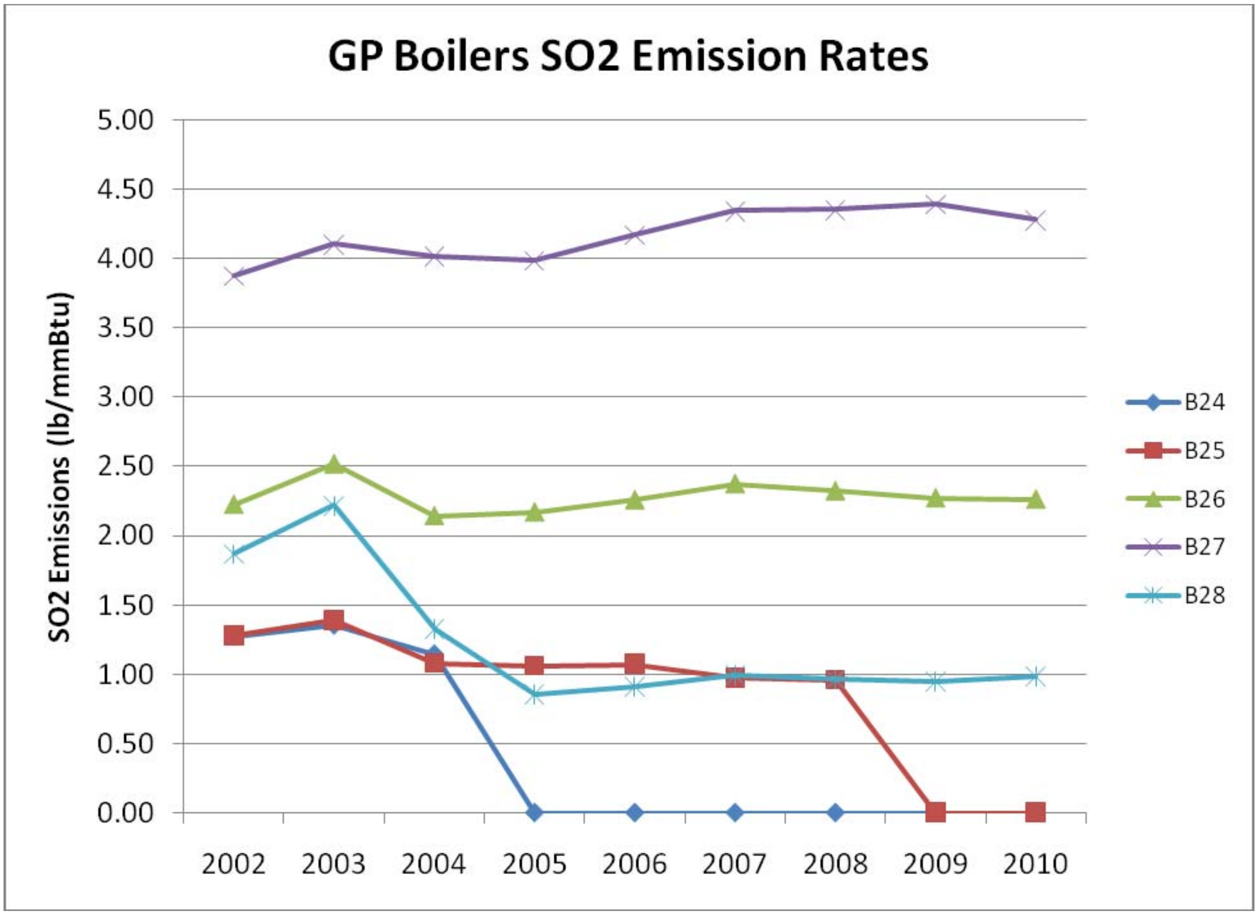
[1] Copeland, S. A., Pitchford, M. L., and Ames, R. B. 2008. Regional haze rule natural level estimates using the revised IMPROVE aerosol reconstructed light extinction algorithm. Presented at the Air & Waste Management Association Visibility Specialty Conference, Moab, April 2008.

a. Selection of 93% SO_2 control efficiency - Wisconsin determined that the technology can achieve 95% control efficiency, but that long term operation and compliance is represented by 93% control efficiency. The entire justification for this adjustment is based on data from the AES Greenridge facility in North Carolina, where a ~1.5% reduction (from ~ 96.8% to ~ 95.3%) in control efficiency was documented due to boiler load swings. Wisconsin fails to note that the control efficiency from AES that already includes the load swings is the 95% figure cited. It appears to be double counting to remove an additional 2% from the 95%. All other examples in Table 2.1 show removal efficiencies of at least 95% or they involve units that have
   - significantly lower pre-controlled levels of SO_2 compared to GP making achievement of 95% control more difficult, and/or
   - are significantly older installations

b. Adjustment of baseline SO_2 emissions. We understand that the State BART rule incorporates the EPA BART guidelines (FR Vol 70, No 128, pg. 39104-39172). The BART guidelines state "the baseline emissions rate should represent a realistic depiction of anticipated annual emissions for the source. In general, for the existing sources subject to BART, you will estimate the anticipated annual emissions based upon actual emissions from a baseline period." Actual emissions of SO_2 for the baseline period are 12,903 tons. Wisconsin "determined that actual SO_2 base year emissions do not fully represent the appropriate basis for established BART SO_2 emission limitations." Additional supporting points included were the need to:
   i. consider existing conditions
   ii. evaluate applicable fuels and the variability that may occur in emission levels
   iii. account for switching to low sulfur content fuels as compared to coke and high sulfur bituminous coals

   "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." The net result of this approach inflates the baseline SO_2 emissions from 12,903 tons to 15,932 tons.

   We believe the inflation of the baseline emissions is without support in the BART guidelines. In addition it is unclear how the hypothetical baseline operating scenario proposed by Wisconsin addresses the issues stated (i-iii above). For example, if representing existing conditions is the concern, then emissions from boilers B24 and B25 would not be included in the baseline, since they have not been run for many years. The second issue suggests that there is emission variability due to fuel switching, but the following graph from data provided by Wisconsin shows little variability other than the shutdown of boilers B24 and B25.



We find no support in the BART guidelines for inflating baseline emissions to account for a control option such as adjusting fuels. We see no reason why the baseline needs to be adjusted to assess the affect of adjusting fuels.

c. The inflated baseline is then used in combination with the low control efficiency as the basis from which to set emission limits. Such an approach leads to "paper" reductions. Based on 2010 operating data, the effective emission rate on the BART boilers that results from the proposed mass cap limit of 5800 tons SO_2 per year is 1.6 lb/MMBtu. This results in an actual control efficiency of about 56% for the BART boilers. This is in stark contrast to the proposed value of 93% or the 95% value we support. This dilution of the BART limit is not allowed in the BART guidelines. They state – "You should consider allowing sources to ''average'' emissions across any set of BART-eligible emission units within a fenceline, so long as the emission reductions from each pollutant being controlled for BART would be equal to those reductions that would be obtained by simply controlling each of the BART-eligible units that constitute BART-eligible source."

d. The original NOx control efficiencies were 84% and 94% for boilers B26 and B27 respectively. These were downgraded to 68% and 84% for boilers B26 and

B27 respectively in the amended BART determination. The following adjustments were made to the previous determination:

i. The combination of inappropriate adjustments that led to the inflated SO_2 limit is used here as leverage to argue that the resulting higher SO_2 concentrations will cause problems for the regenerative selective catalytic reduction (RSCR) system. We note that the original BART stack limit of 0.58 lb/MMbtu would not have this issue. The proposed difficulty is predicated on the SO_2 scrubber running at artificially low removal efficiencies - approximately 67% control efficiency based on the proposed SO_2 limit of 1.01 lb/MMBtu or 50% control efficiency based on the proposed 30-day rolling limit of 1.55 lb/MMBtu. This is in stark contrast to the ability of the technology to remove in excess of 95% of the inlet SO_2. Please set the SO_2 limit to reflect the capabilities of the scrubber.

ii. It is our understanding that the emissions from all the boilers come into a common header before being split into two parallel flues. The discussion in the amended BART determination which assigns one flue to one boiler is theoretical. The flues could just as easily be combined if necessary. In the proposal submitted by Babcock they give estimates for a parallel system of two turbosorb units and two RSCR systems but stress that "Although not presented herein, BPEI does suggest further consideration of a single train DFGD design as the most cost effective AQCS solution for this site. While critical moving components, such as fans, could remain redundant, the large major components such as the turbo reactor and baghouse could easily be designed to carry 100% of the design flue gas flow, and at significantly reduced capital and installed cost."

iii. The assumed control efficiency for RSCR was dropped 75% to 70% to allow for a "compliance margin." Please comment why a compliance margin is needed now when it was not previously. It is our understanding that the quote provided by the manufacturer already includes consideration of uncertainties with the system.

iv. We continue to believe an RSCR system should be installed for the BART units per the previous determination.

e. Compliance – Wisconsin proposes both emission rate and mass emission limits. We are unaware of any basis in the BART guidelines for mass emission limits.

i. The 12 month mass cap is viewed as being consistent with achieving a "long-term average BART level of control." We are unaware of any long-term level of BART control specified in rule or guidance. Visibility is perceived instantaneously so emission limits established to improve visibility should be short term.

ii. The 30 day limit is calculated by applying the inflated emission SO_2 rate (see comment c. above) to the max daily heat rate value and multiplying by 30 days. Why not instead find the highest 30-day block value or the average 30-day black value over the baseline period? The proposed approach leads to an inflated mass cap.

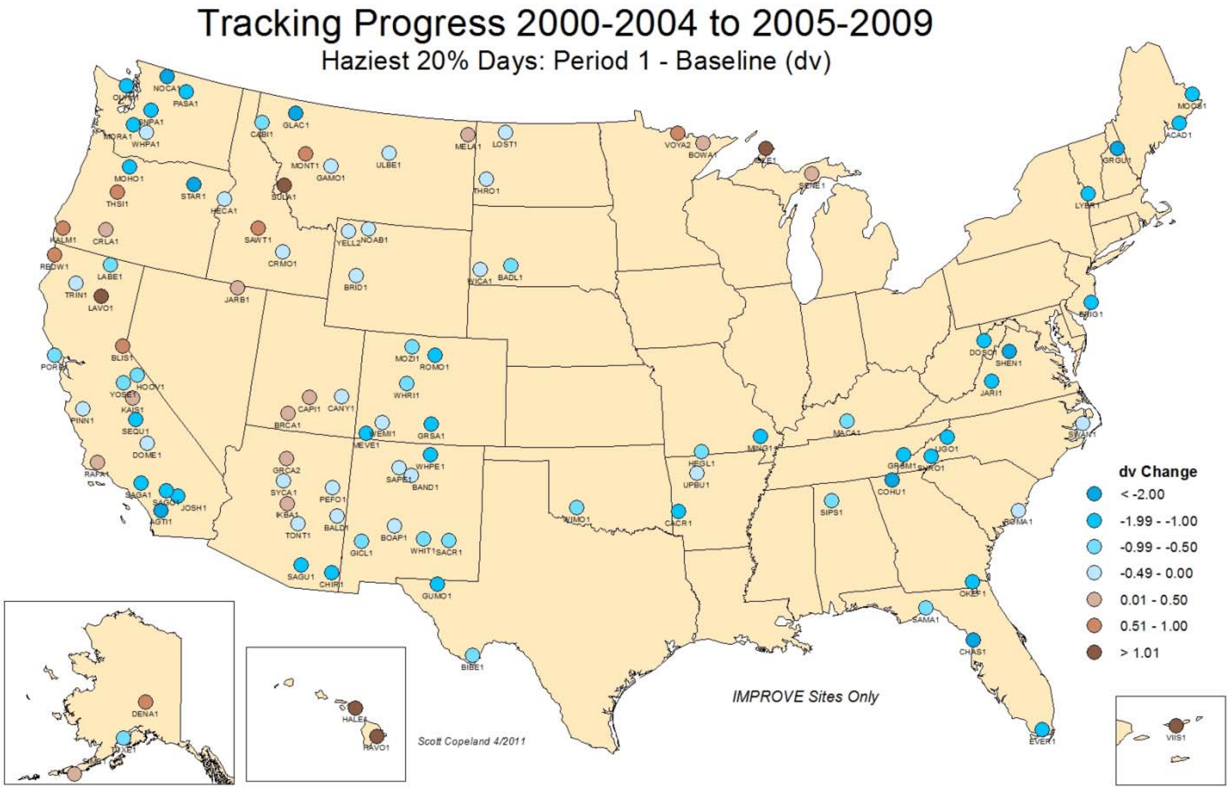
iii. Interpollutant trading – we are unaware of any basis in the BART guidelines for interpollutant trading. This option when used in combination with the inflated SO_2 emission limits and mass caps could allow GP the real possibility of not installing any NOx controls at all by "over-controlling" SO_2 from boilers B26 and B27 through the application of a scrubber. The previous BART determination prescribed both a scrubber *and* RSCR for NOx controls.

Reasonable Progress/Long Term Strategy

6. On page 27 Wisconsin appears to believe that the Boundary Waters Canoe Area Wilderness (BOWA) and Voyagers National Park (VOYA) meet the uniform rate of improvement (URI, also known as the URP - uniform rate of progress). This conclusion was based on one of the MRPOs modeling runs (using a 2005 base year). The State of Minnesota in setting the reasonable progress goal (RPG) for 2018 in their RH SIP looked at numerous predictions of visibility in 2018. The MPRO 2005 base year run was the only one that showed BOWA below the URP. Minnesota ended up setting the RPGs for both of its Class I areas above the URP due to uncertainties with the different modeling runs. Therefore it is incorrect to say that BOWA and VOYA meet the URP.

7. On the same page Wisconsin appears to assume that if a Class I areas is below the URP the four factors at 40 CFR 51.308(d)(1)(i) do not apply. We understand that all the factors, including the comparison to the RPG, apply. Please correct this section.

8. Analysis of recent visibility data shows that in the eastern US only the Northern Class I Areas have degraded since the baseline period (see figure below from upcoming IMPROVE Report). This means the amount of work to achieve the RPGs has increased. Please note this in the SIP.



9. On page 31 Wisconsin states "Additional information developed by the MRPO process supports the previous conclusions that the existing control programs and BART meet the RPG requirement through 2018."

   Wisconsin goes on to cite the EC/R "Factor" study as supporting its conclusion. We disagree. The EC/R study looked at controls beyond existing levels and concluded that additional controls on EGUs and ICI boilers are feasible. Page 101 of the report concluded that "Most of the projected cost-effectiveness values for potential additional controls (Table 6.1-1) are within the range of cost-effectiveness values estimated for on-the-books controls (Table 6.1-2)."

   No facility-specific cost analyses were presented in the SIP to counter the claims of the EC/R study.

10. Reasonable progress examines all sources with potential impacts to the Class I areas for the applicability of pollution controls regardless of their BART status. A number of States across the United States have installed controls on sources under reasonable progress. In the most recent draft RH SIP you identify a list of sources expected to have the largest visibility impact. In Tables 8A and 8B you indicate what is known regarding plans for additional pollution controls at each listed facility. For those sources where controls are not being proposed, please comment whether cost effective controls are nonetheless available. As we commented previously, we are especially interested in the

numerous industrial boiler sources (e.g. Thilmany, PCA-Tomahawk, Stora Enso, etc). It is our understanding that many of these sources burn a high sulfur fuel and have little or no sulfur controls, in which case cost effective controls should be easily identified. Please provide the boiler type and size, fuel(s), and the presence of any pollution controls for each source in Tables 8A and 8B.

11. We believe that the regional haze rule requires that the sources in Tables 8A and 8B be studied under the reasonable progress/long term strategy portion of the rule and controls required with this RH SIP. We do not agree that the application of controls on these sources is dependent on a new modeling run and/or whether the Northern Class I areas are predicted to meet the URP line. The URP line is just one of the factors to consider in the evaluation of controls - it does not trump the others.

12. Please include the following statement concerning the EC/R study that was deleted from the first draft of the RH SIP "EC/R concluded that the "EGU-1" reductions in SO_2 for the 3-state region (based on IPM Version 2.1.9) could be sufficient to reach the glide-path line at Isle Royale National Park and Seney Wilderness Area (northern Michigan) and Boundary Waters Canoe Wilderness Area (northern Minnesota), but that additional control measures would likely be needed to reach the glide path line for Voyageurs National Park (northern Minnesota)." This shows that the nearest states can achieve the URP if they choose to do so.

13. Please share the page number in the EC/R report for this conclusion, we cannot find it - "Another portion of the EC/R analysis showed that additional progress in visibility for Seney and Isle Royale is limited by the time necessary for compliance rather than potential control levels and cost."

14. The mere existence of future rules affecting the same sources (e.g. 1-hr NAAQS, or industrial boiler MACT) does not preclude the application of the Regional Haze Rule. If the existence of future rules precluded the application of current rules, then no regulations would ever be applied. In the response to comments section of the BART determination for Georgia Pacific, Wisconsin supports this idea when it states (Page 112) "The Department cannot anticipate or regulate based on *future* potential requirements." If the order was different would Wisconsin delay the implementation of, for example, the 1-hr SO2 NAAQS because the Regional Haze Rule was due in a year? Also just because EPA needs more time to evaluate the entire fleet of ICI boilers across the US does not mean Wisconsin should delay control determinations for its handful of highest visibility-impacting industrial boilers under reasonable progress/long term strategy.

15. Page 34 "…the states will not be able to implement deeper emission reductions more rapidly than current regulatory program efforts." We are curious what Wisconsin thinks the Regional Haze Program is if it is not a "current regulatory program effort"?

16. Page 34 – "Since the time for compliance is a limiting step the consideration of the other RPG factors is not evaluated for this RPG determination." As stated above we do not

agree that the time for compliance is a limiting step. We also do not agree that one of the four factors can prevent evaluation of the others. Please evaluate all the factors.

17. Page 35 - "Of the five MWPO states, Michigan and Minnesota have higher contribution to Seney and Isle Royale compared to Wisconsin." This is contradicted by Table 1 in the draft RH SIP.

18. With respect to the September 19, 2007 letter sent by the State of Minnesota asking for specific emission reductions. A quote from this letter follows.

    "In particular, Minnesota asks Iowa, Missouri, North Dakota, and Wisconsin to evaluate further reductions of SO_2 from electric generating units (EGU) in order to reduce SO_2 emissions by 2018 to a rate that is more comparable to the rate projected in 2018 for Minnesota, approximately 0.25 lbs/MMBtu. Minnesota believes that Illinois is already in the process of meeting this goal. Emission reductions in Wisconsin are particularly important, as Wisconsin is the highest contributor outside Minnesota to visibility impairment in Minnesota's Class I areas."

    Wisconsin estimates that it will achieve 0.29 lb/MMBtu by 2014, based largely on its CATR budget. Actual emissions in 2014 could exceed the budget due to banked allowances. What will Wisconsin commit to do if it does not meet Minnesota's requested rate of 0.25 lbs/MMBtu in 2018?

19. Page 38 - "ICI boilers were also reviewed by EC/R, and showed potentially reasonable additional controls on a cost basis. WDNR may use results from the EC/R study for reasonable controls for ICI boilers – should Wisconsin's long-term strategy be determined to be insufficient – with a focus on the significant emission sources in Tables 8A and 8B in the Reasonable Progress Goals section." We agree with this statement except that we believe the determination of reasonable controls for these sources should be included in this SIP.

20. Page 39 - "The MRPO TSD shows that the reasonable progress goals for the Northern Class I areas in northern Minnesota (Boundary Waters and Voyageurs) will be achieved by 2018 from implementation of "on the books" and "will do" control measures in the states contributing to visibility impairment,…" Minnesota felt the need to ask for emission reductions from Wisconsin because the projected reductions were not enough to achieve its RPG. Please clarify this statement.