BEFORE THE
DEPARTMENT OF NATURAL RESOURCES

Notice of Public Hearing

State Implementation Plan (SIP) to Address Requirements of the Federal Regional Haze Rule

NOTICE IS HEREBY GIVEN that pursuant to s. 285.13(1), Wis. Stats., the Department of Natural Resources will hold a public hearing on the proposed Regional Haze SIP for the State of Wisconsin.

Background

The Regional Haze Rule was adopted on July 1, 1999 (*64 FR 35714*) and incorporated under 40 CFR part 51.308 as part of Subpart P – Protection of Visibility. The Clean Air Act (CAA) under section 169A(b)(2) requires each state with a residing listed Class I area – and any state from which emissions are reasonably anticipated to cause or contribute to any impairment of visibility of such a Class I area – to make reasonable progress towards remedying impairment from man-made air pollution. Wisconsin, being identified as a contributing state, is specifically subject to requirements under the regional haze program, 40 CFR Part 51.308.

In accordance with 40 CFR Part 51.308, the Department has developed a draft Regional Haze SIP based on the requirements of the Regional Haze Rule. This document describes Wisconsin's fulfillment of SIP requirements established by the rule for purposes of remedying and protecting visibility in designated federal Class I areas. The document includes Wisconsin's strategy for meeting reasonable progress goals by 2018 for Class I areas – which relies primarily on existing control programs across different source categories – and implementation of Best Available Retrofit Technology (BART) for affected major sources.

NOTICE IS HEREBY FURTHER GIVEN that the public hearing will be held on:

Tuesday, September 13, 2011 at 10:00 a.m.
Wisconsin Department of Natural Resources, Room 713
101 S. Webster Street
Madison, WI 53707-7921

NOTICE IS HEREBY FURTHER GIVEN that pursuant to the Americans with Disabilities Act, reasonable accommodations, including the provision of informational material in an alternative format, will be provided for qualified individuals with disabilities upon request. Please call Jonathan Loftus at (608) 264 - 8868 with specific information on your request at least 10 days before the date of the scheduled hearing.

Written Comments and Copies of Documents

Written comments on the proposed Regional Haze SIP may be submitted to Mr. Jonathan Loftus, Bureau of Air Management AM/7, P.O. Box 7921, Madison, WI 53707 no later than **September 16, 2011**. Comments may be submitted electronically to jonathan.loftus@wisconsin.gov. Written comments will have the same weight and effect as oral statements presented at the hearing.

A copy of the documents for the proposed Regional Haze SIP may be downloaded from http://dnr.wi.gov/air/aq/particles/vishaze.htm or a hard copy may be obtained from:

Jonathan Loftus AM/7
Bureau of Air Management
P.O. Box 7921
Madison, WI 53707
Jonathan.Loftus@wisconsin.gov
Phone: (608) 264-8868
FAX: (608) 267-0560

Dated at Madison, Wisconsin 8/1/11

STATE OF WISCONSIN
DEPARTMENT OF NATURAL RESOURCES

By Matt Moroney
for Cathy Stepp, Secretary

STATE OF WISCONSIN
DEPARTMENT OF NATURAL RESOURCES

Notice/Permit Number:
Hearing Notice

Proposed Ozone Redesignation Request and Maintenance Plan Supplement for the Milwaukee-Racine Nonattainment Area and the Sheboygan County Nonattainment Area

&

State Implementation Plan (SIP) to Address Requirements of the Federal Regional Haze Rule

Linda Lund, being first duly sworn on oath deposes and says that said person is employed as a Office Operations Associate, by the State of Wisconsin Department of Natural Resources; that on the 8th day of August, 2011, said person deposited in the United States mail at Madison, Dane County, Wisconsin, copies of the notice for public hearing to the above entitled action, securely enclosed in envelopes, the postage duly prepaid and one copy addressed to each of the following at his/her respective last known address; and e-mailed the same to the interested parties who have requested to receive the public notices via e-mail:

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Publication to appear in:
The DNR will publish in:
Wisconsin State Journal
PO Box 8056
Madison, WI, 53708-8056
On Thursday, August 11, 2011

Public Hearing Contact:
Jonathan Loftus –AM/7
Bureau of Air Management
Phone: (608) 264-8868

Location and date of hearing:

Tuesday, September 13, 2011 at 1:00 p.m.
Wisconsin Department of Natural Resources.
Room 713
101 S. Webster Street
Madison, WI 53707-7921

Linda Lund
Linda Lund, Office Operations Associate
Bureau of Air Management
608-264-9206

Subscribed and sworn to before me

this 8th day of August, 2011

Barbara Swenson
Notary Public, State of Wisconsin

My commission expires: 11/30/2014

NOTARY PUBLIC
BARBARA SWENSON
STATE OF WISCONSIN

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AUG 16 2011
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BEFORE THE DEPARTMENT OF NATURAL RESOURCES
Notice of Public Hearing
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In acco[illegible] Part 51.308, the Department has developed a draft Regional Haze SIP based on the requirements of the Regional Haze Rule. This document describes Wisconsin's fulfillment of SIP requirements established by the rule for purposes of remedying and protecting visibility in designated federal Class I areas. The document includes Wisconsin's strategy for meeting reasonable progress goals by 2018 for Class I areas – which relies primarily on existing control programs across different source categories – and implementation of Best Available Retrofit Techeology (BART) for affected major sources.

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[illegible] Comments and Copies of Documents

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[illegible] documents for the pro[illegible] SIP may be down[illegible]
[illegible]r/aq/particles/vis[illegible] copy may be ob[illegible]
[illegible] AM/7, Bureau of Air [illegible] Box 7921 Madison, [illegible]
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[illegible]one: (608) 264-8868
[illegible]X: (608) 267-0560
[illegible]ted at Madison, Wisconsin : 8/1/11
[illegible]ATE OF WISCONSIN
[illegible]PARTMENT OF
[illegible]TURAL RESOURCES
[illegible]: Matt Moroney for
[illegible]thy Stepp, Secretary
PUB. WSJ: August 11, 2011
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[illegible]ONSIN }
[illegible]County } ss.

SHARON SCALLON

being duly sworn, doth depose and say that he (she) is an authorized representative of Capital Newspapers, publishers of

PWSJ **Wisconsin State Journal**

a newspaper, at Madison, the seat of government of said State, and that an advertisement of which the annexed is a true copy, taken from said paper, was published therein on August 11th, 2011

(Signed) Sharon Scallon

(Title) Principal Clerk

Subscribed and sworn to before me on

8.12.11

Notary Public, Dane County, Wisconsin

My Commission expires April 15th, 2015

BART Requirements for Wisconsin Sources – Response to Public Comment

Wisconsin is required to implement a Best Available Retrofit Control program according to 40 CFR part 51.308(e) of the Federal Regional Haze Rule. The Department initially proposed BART requirements for public comment in June of 2010. Based on received comment and analysis, the Department re-proposed BART requirements in July of 2010 for public comment. On the re-proposed BART the Department received comment from Georgia Pacific, U.S. Forest Service, National Parks Service, U. S EPA, and joint comment from Sierra Club and the Midwest Environment Defense Center. This document comprises the Department's response to specific and identified areas of comment to the BART determination for the Georgia Pacific Broadway Mill, Green Bay Wisconsin and for the Electric Utility Sector.

Herein the U.S. Forest Service and National Parks Service when addressed in common are referred to as the Federal Land Managers (FLMs). The Wisconsin Department of Natural Resources is referred to as the Department.

I. Georgia Pacific BART Requirements

1.0 Baseline Emissions

Comment 1.1: The baseline emissions used in calculating baseline emissions should reflect boilers “shut down” of boilers B24 and B25 with zero emissions.

Response: The Department agrees that boiler B24 should not be included in calculating a mass cap requirement. Georgia Pacific began curtailing operation of this boiler during the BART baseline years with no operation by 2005 and after.

The Department maintains that boiler B25 baseline emissions should be included in calculating a mass cap requirement for the stack S10 boiler system. Boiler B25 operated continuously during and since the BART baseline years until 2009 when the boiler potentially became subject to the Clean Air Interstate Rule (CAIR). Georgia Pacific elected to not operate the boiler pending a review by U.S. EPA for determining CAIR applicability. In May 2, 2011, U.S. EPA provided a determination, appendix A, that boiler B25 is not subject to CAIR. Therefore this boiler is no longer restricted in operation.

The Department believes using operation during the BART baseline years is representative of boiler B25 returned status to full allowable operation. This is supported by looking at the total heat input for the stack S10 boiler system. Before and after boiler B25 operation was halted the total stack heat input remains relatively constant. This indicates that boiler B25 load was simply switched to the other boilers. Therefore non-operation of boiler B25 was not due to a reduced need of load or necessarily reflect the normal dispatch of the stack S10 boiler system. Therefore the consistent approach for reflecting operation of all affected boilers, including B25, is the use of the baseline years emission and operation data.

Comment 1.2: The U.S. EPA, Federal Land Managers, and Sierra Club commented that baseline SO_2 emissions should not be calculated using a design fuel but rather reflect actual historic emission levels.

Response: The Department agrees. The finalized baseline emissions reflect actual historic emission levels during the BART baseline years of 2002 to 2004. Specifically, the 12 month rolling mass cap is calculated using the three year average of SO_2 emitted during 2002 to 2004 for each boiler, except B24, in the stack S10 system. The 30 day rolling average emission cap is calculated using the SO_2 average emission rate for each boiler during the baseline years applied to the boiler's heat input demonstrated during the 30 day heat input of maximum heat input during baseline years for the total stack S10 system.

Comment 1.3: The Department, in proposing BART, evaluated appropriate fuels for purposes of calculating adjusted baseline emissions; i.e. determining a boiler design fuel. The U.S. EPA states that fuel switching is a control option and should be evaluated in the context of actual historic fuels and operation.

Response: The Department concurs and evaluated fuel switching as a control option. The information developed for fuel switching cost and visibility improvement provided in the July 2011 proposed BART determination, section 3 page 12, is applicable to this evaluation. Based on this information, the Department determined that the control measure of switching petroleum coke fuels to the baseline fired bituminous coals is appropriate for both B26 and B27 boilers. For boiler B27, the fuel switching beyond the current low fusion coal can negatively affect the combustion and necessary slagging characteristics of the cyclone furnace. Therefore, switching petroleum coke to low fusion coal is the only option evaluated and was determined cost-effective at 1,505 $/ton. For boiler B26 a stoker boiler, options are considered for switching fuels from petroleum coke to the baseline bituminous coal and to low sulfur bituminous coals. The switch to low sulfur bituminous coal is eliminated based on marginal costs at 1.5 to almost 2 times the switch to baseline bituminous coals.

Comment 1.4: The Department proposed a 30 day rolling mass cap compliance requirement that reflects heat input equivalent to 90% capacity utilization of the stack S10 boiler system. The U.S. EPA commented that full utilization is greater than past actual operations and will result, on average, in less than BART control under a mass cap. The U.S. EPA also recommended that the 30-day average mass cap be calculated using historic operating levels which occurred during the BART baseline years.

Response: The Department agrees and is amending the 30 day rolling mass cap calculation to reflect historic operating levels. The mass cap now reflects the maximum 30 day heat input demonstrated for stack S10 system (excluding boiler B24) during the BART baseline years. This maximum 30 day heat input is then multiplied by the average baseline year emission rates for each boiler after applying BART controls. This approach establishes a mass cap which is used to represents the allowed maximum 30 day emissions after BART. It is important to note that this level of emissions is less than taking the maximum 30 day heat input multiplied by the maximum demonstrated emission rates of each boiler and then applying BART control levels. The proposed 30 day mass cap is also less than would occur when if using the maximum of single day emissions demonstrated during the baseline years. This maximum single day value was used in modeling visibility impact for assessing BART control options. Therefore the currently proposed 30 day mass cap results is a requirement more protective, on the whole, of visibility than predicted by the modeled results for BART controls.

The Department also points out that the 30 day rolling mass cap is meant to work together with the more restrictive 12 month rolling mass cap. The 12 month rolling cap is the driver for meeting the BART controls on a long-term basis while the 30 day rolling mass cap ensures visibility impacts do not exceed modeling visibility improvements for BART. Refer to response to comment 5.2.

2.0 SO2 Controls

Comment 2.1: The U.S. EPA and Federal Land Managers commented that 95% control efficiency for the flue gas desulfurization equipment accounts for necessary variability in control levels and the Department applying a 2% compliance margin in determining a 93% control compliance requirement double counts any needed adjustment for control variability. Sierra Club commented that a SO_2 control level of at least 95 % should be reflected in the BART compliance requirement.

Response: The U.S. EPA and FLM recommendations are based on a particular technology (Turbosorp), under a spray dryer sub-category (CFB). In evaluating BART for SO_2 at Georgia-Pacific, Department maintains that it is necessary to consider the weight of evidence for the spray-dryer category as a whole, not limiting the evaluation to just CFB or Turbosorp in particular. The Department emphasizes that the Turbosorp technology has very limited demonstration. Greenidge Unit 4 – the primary reference for Turbosorp application at Georgia-Pacific – has not operated since the end of testing in 2008, as far as the Department is aware. The Deerhaven testing for 95+ % control was for a duration of 12 hours and is not appropriate for establishing a long-term control level at Georgia-Pacific. Further, with taking coke out, the inlet at GP becomes 3.0 Lb/mmBtu, whereas the testing at Greenidge Unit 4 was 3.6 Lb/mmBtu on average. For these reasons, it is questionable to use Turbosorp technology as the sole basis for a BART control level.

Under this approach, the Department is proposing a (conservative) starting control efficiency of 95% based on SDA, along with a sufficient compliance margin, for an SO_2 control level of 93% on boilers B26 and B27 combined with removal of coke. The total control level on boilers B26 and B27 from the baseline is 94.2%. The 93% control level is higher than any other proposed BART control for a non-EGU, as far as the

Department is aware. North Dakota dismissed CFB at 93% control in its BART analysis in part specifically because of its limited demonstration. The highest BART control proposed using SDA technology is 92% control, and the other BART proposals using SDA technology are at 90% control or less. It seems that many BART proposals used a default control level of 90% based on information from EPA's SO_2 Control Manual. Also, the Cross-State Air Pollution Rule (which is proposed as equivalent to BART for BART-subject utilities) applies an SO2 control of only 92%.

3.0 NOx Controls

Comment 3.1: The U.S. EPA requested additional justification for reducing the NOx control efficiency of RSCR control equipment from 80% to 70%.

Response: In the July 2011 draft BART finding the Department proposed an operating NOx control efficiency of 75% for RSCR and applied a 70% reduction in allowing for a compliance margin and determining final compliance requirements. The Department continues to believe these control levels are appropriate in making the BART determination. Refer to response to comment 5.3 for discussion of compliance margins.

The Department originally proposed 75 to 80% control efficiency for RSCR in June of 2010 as a basis for further investigation. At that time, initial discussions with the vendor, Babcock Power Inc., indicated the higher range of RSCR control efficiencies may result in ammonia slip of up to 13 ppmdv. The RSCR system is comprised of multiple canisters containing single layers of catalyst and operates with flue gas being treated by alternating canisters while the non-treating canisters are reheating. As flue gas is switched between canisters, small amounts of flue gas may exit the common header system without first passing through the catalyst beds – therefore momentary puffs of untreated flue gas and un-utilized ammonia occur. Traditional SCRs are designed for a maximum ammonia slip of 5 ppmdv or less. Assuming slip at the same rates as a traditional SCR and along with the momentary puffs a RSCR more total ammonia than a normal SCR. This consequence of the RSCR needs to be considered further in setting final control levels.

Since the initial BART assessment, Babcock Power provided a ROM equipment estimate for applying RSCR to the Georgia Pacific stack S10 boiler system. In that estimate Babcock Power stated a design control efficiency of 75% with a maximum 10 ppmdv ammonia slip. Although less than 13 piped, the total RSCR ammonia slip is still expected to be more than a traditional SCR. The Department acknowledges that with lower control efficiency less ammonia slip is likely to occur. Because ammonia can contribute to particulate and visibility issues allowing for further minimization of ammonia slip closer to traditional SCR levels may be warranted. The Department considers this a secondary factor in evaluating appropriate compliance margins. Actual operation in meeting the current proposed 70% compliance requirement is assumed to be 75%, but being able to achieve control consistently below 75% will further reduce puffs of uncontrolled NOx and ammonia slip.

As stated Babcock Power's equipment quote specifies a 75% control efficiency level which the Department further confirmed with Babcock Power as an appropriate long term control level for RSCR applied to a coal fired unit[1]. The Department then applied a compliance margin in determining the final compliance requirement. In this case the compliance margin may allow for further reduced ammonia slip if Georgia Pacific can trim closely to a 70% control level. However, the compliance margin mainly addresses that an RSCR is a new configuration and operating approach to SCR control technology. The RSCR is operating successfully on biomass fired boilers which in some cases is more difficult, but to date the RSCR has not been applied to the higher NOx levels of coal fired boilers. Therefore, without actual operating data on similar sources the Department believes allowing for a 5% compliance margin is appropriate under the Georgia Pacific BART determination.

Comment 3.2 The Department proposed in the July 2011 Draft BART finding that regenerative selective catalytic reduction (RSCR) is applicable to boiler B27, but not to boiler B26. The U.S. EPA and Federal Land Managers requested justification for this determination when both boilers exhaust to a common stack where the RSCR technology is typically applied.

Response: The Department maintains that RSCR is applicable to boiler B27 and not to boiler B26 in determining BART requirements. This finding is based on both the physical equipment configuration and resulting high cost of applying RSCR to boiler B26. As a note - one of the original concerns described in the 2011 BART finding for applying RSCR to boiler B26 was the potential for high SO_2 concentrations in the flue gas which could result in SO_3 plume. This concern is no longer applicable based on the finalized BART SO2 requirements.

This point first clarifies the discussion in the 2011 finding concerning RSCR and the existing equipment configuration. All of the boilers B25 to B28 exhaust into a common flue duct. However, this duct then splits evenly before entering two parallel fabric filter units housed inside of a building. A flue duct exits from each fabric filter out of the building and enter opposite sides of the flue stack. The flue ducts then rejoin only once inside the stack. The default placement of the RSCR is between the fabric filter system and the stack where there are still two separate ducts. Therefore the default configuration is to place two separate RSCR units – one on each flue duct. The previous discussion further identified that under this configuration one duct corresponds to the flow rate and emissions equivalent of boiler B27. Therefore this RSCR system and cost is attributed to boiler B27. This RSCR placement is deemed cost-effective for BART purposes.

Under this configuration the control of boiler B26 requires a RSCR be placed on the second flue duct between the fabric filter and stack. The cost of this unit is then placed

[1] Babcock Power, personal communication

against the flow rate and emissions equivalent of boiler B26[2]. In looking the RSCR based control options the highest control level is achieved by overfire air and flue gas recirculation on the boiler followed by the RSCR control (OFA/FGR/RSCR). This configuration results in a 0.11 deciview improvement at a cost of approximately 15.6 million dollars per deciview improvement (M$/dv). The next lower control option of OFA/FGR/SNCR achieves a 0.09 deciview improvement at 9.1 M$/dv. Also significant is that the capital cost of the RSCR based system is 9.9 M$ and the SNCR based system is 4.4 $M. This shows the RSCR system will achieve only 0.02 deciview improvements while incurring significant additional cost compared to the SNCR based system. In this case the RSCR based system is not considered BART.

Comment 3.3 U.S. EPA requested additional justification for reducing the control efficiency of overfire air NOx control as applied to boiler B27 from 60% to 50%.

Response: In the July 2011 draft BART finding the Department proposed an estimated operating NOx control efficiency of 52% for overfire air and applied a 50% reduction in allowing a compliance margin and determining final compliance requirements. The Department maintains these control levels are appropriate in making the BART determination. Refer to response to comment 5.3 for discussion of compliance margins. To note is that the overfire air achieves higher NOx control efficiency for the B27 cyclone boiler than can be achieved on the B26 stoker boiler.

The quoted 60% control was originally proposed in the June 2010 Draft BART finding for purposes of obtaining comment and further information. Since that time the Department evaluated historic emissions data before and after operation of overfire air on cyclone boilers of similar size and fuel operated at the Wisconsin Nelson Dewey electric utility plant. The overfire air of this boiler is operated with neural network type of system which is believed to represent best operational levels for reducing NOx emissions while under optimal combustion efficiency conditions. Although, 60% control efficiency is technically achievable it may come at the expense of poor combustion characteristics and increased emissions of incomplete combustion such as carbon monoxide, dioxins and furans. Under the currently proposed ICI MACT regulation, these hazardous pollutants are to be controlled through good combustion practices. The Department believes an overfire air control efficiency should not be set that potentially works against the MACT requirement and good combustion efficiency. Further the Department believes the Nelson Dewey plant's well operated overfire air system is an appropriate basis for overfire air control levels applied to cyclone boilers under these constraints. Reviewing emissions data for Nelson Dewey's two cyclone boilers demonstrates 52% NOx control due to the overfire air system on an annual basis. Because this is a demonstrated control level the final compliance requirement can be set using a small compliance margin. A 2% compliance margin is allowed resulting in an overall 50% compliance control efficiency. Refer to response to comment 5.3 for discussion concerning the use of compliance margins.

[2] WDNR, 2011, *BART Determination – Amended July 2011, Georgia Pacific Broadway Mill, Green Bay Wisconsin*, section 4, page 26, Table 4.3 July 1, 2011.

4.0 Particulate Controls

Comment 4.1: The National Parks Service commented that the proposed particulate emission limit, 0.30 lbs/mmBtu for stack S10, does not reflect achievable emission levels with the existing fabric filter control system. Further, if this emission limit is maintained, then the Department needs to demonstrate this level of emissions results in no significant impact to visibility.

Response: In meeting SO_2 mass caps the emissions from the stack S10 boilers, if continuing to burn coal fuels, must be controlled by some level of lime injection. In this case, particulate loading to the fabric filter system will increase substantially. Therefore restricting the system to lower particulate emission levels is likely contrary to visibility improvement gained from the SO_2 reduction. At a minimum the exact design point for particulate loading and emissions versus SO2 control is still to be determined in final equipment design. Therefore the Department has concluded it is not appropriate to restrict particulate emissions based on actual emissions when particulate loading will be changing as a result of another portion of the BART requirement.

In determining controls for particulate and SO_2 emissions, Georgia Pacific will also have to consider the pending ICI Boiler MACT emission limitations. Currently the ICI boiler MACT is proposing filterable particulate emission limits for coal boilers ranging from 0.028 to 0.088 lbs/mmbtu. This suggests that the final MACT limits will be more stringent than the previously adopted 0.3 lbs/mmbtu total particulate emission limit.

Because the design load of particulate to the fabric filter related if SO_2 control is pending and because the MACT particulate requirement is also pending the Department is not proposing to further restrict particulate control below the current permitted level.

5.0 BART Control Levels and Compliance Requirements

Comment 5.1: The Federal Land Managers and Sierra Club commented that a mass cap does not represent BART level of control; i.e. the BART control levels are may not be achieved while the boilers are operating at low loads.

Response: The Department maintains that a mass cap is an appropriate mechanism for implementing continuous control compliance requirements. Using a mass cap approach in meeting continuous emission limit requirements, such as RACT, is established under the U.S. EPA policy for economic incentive programs (EIP). The applicability of the EIP policy is discussed in the response to comment 6.2. However, the methods used in establishing BART mass cap requirements inherently ensure that BART control levels or better visibility improvement is achieved in all cases as discussed below. Further, if exceeding normal high operating levels, Georgia Pacific must implement higher control levels than determined for BART. Also to note here is that the mass cap acts to ensure emissions are not simply switched to non-BART boilers. This is compared to an emission rate approach where total capacity utilization and emissions can exceed the proposed BART mass caps.

Establishing mass caps from the baseline year average emissions will ensure ongoing overall control levels consistent with BART control. For both SO_2 and NOx, emission levels for stack S10 remain fairly constant from 2002 to 2010, summarized in the table below. This information shows that there has been no extended period of low load operation significantly affecting overall operations from year to year. In looking at the baseline year average emissions the BART controls result in an average 81% and 72% control of SO_2 and NOx emissions, respectively. Based actual historic emissions the average SO_2 control will potentially range from 79% to 82%. A further case is looked at where the baseline year average emission rates are multiplied by the low and high heat inputs demonstrated for the stack S10 system to further check control sensitivity – using the baseline year emission rate would be the same basis as evaluating control levels under an emission rate limitation. Here potential control levels range from only 78% to 82%. This evaluation shows that overall control levels based on normal historic operation are likely to be greater as much as less than the BART determined control efficiencies. In fact, Georgia Pacific will have to pursue greater reductions they increase facility production and steam requirements. These same conclusions hold true for the NOx BART control levels. These same conclusions are supported by the most recently available data for 2010 which shows required control levels for both SO_2 and NOx are substantially the same as for BART.

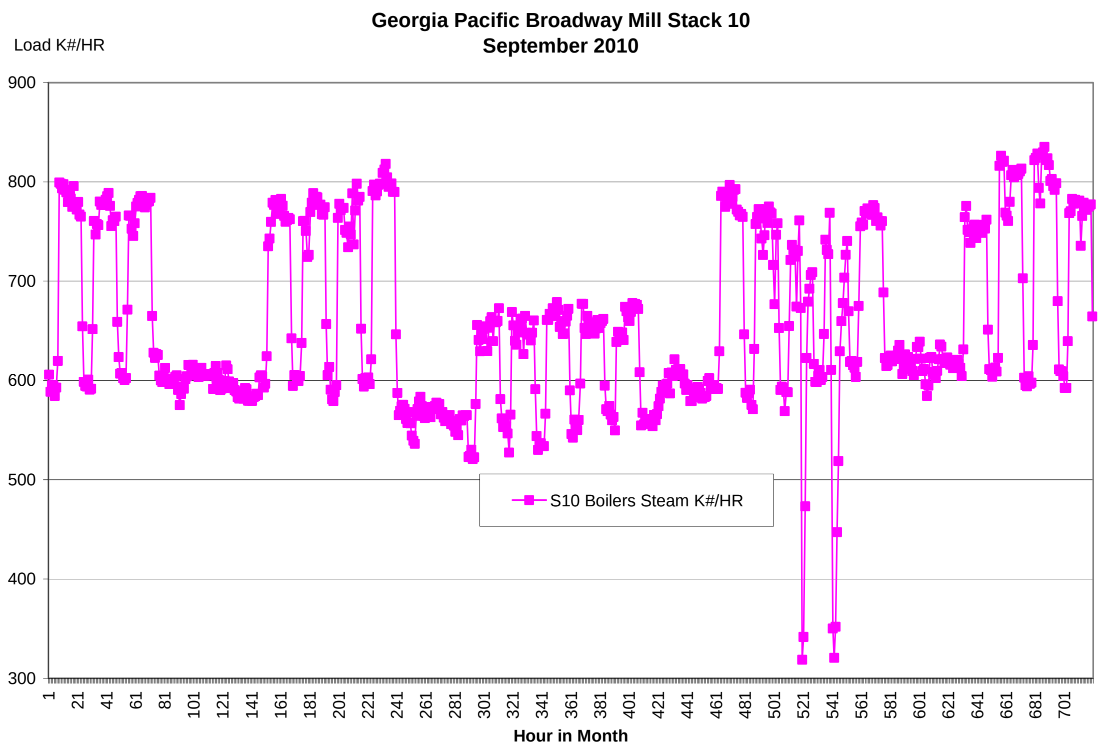
On a daily basis, Georgia Pacific will have to meet control levels consistent with the BART control levels. A chart of stack S10 steam load for stack S10 shows the range between high and low loads are very consistent and that daily cycling is consistent as well. This supports that there is not one or a few types of load situations where Georgia Pacific can significantly curtail load. Basically, the boiler normal operations are consistent and therefore reflected by the long term average operations. Therefore the mass cap based on average operating levels accounts for the range of demonstrated load swings over short periods. Further because of the frequency of operating at both low and high loads Georgia Pacific cannot target the curtailment of control equipment operation at any one specific level without significant impact. This information supports the conclusion that Georgia Pacific will not be able to substantially alter the actual efficiency of control equipment or curtail emission reduction measures responding to BART on a prolonged basis.

Ultimately, it is prudent for Georgia Pacific to control at both high and low loads to ensure that unplanned or higher production levels than normal can be accommodated as needed. However, it is worth evaluating the impact to visibility in the event control levels are less than BART. If Georgia Pacific decides to reduce control levels at lower loads then reductions must be made up at higher load levels. Since high loads are the periods of higher emissions increasing the control efficiency during these periods will have the greatest benefit in reducing visibility impacts. At lower loads, the emissions have a lower initial visibility impact than at the higher loads. Therefore this potential approach to BART controls has greater overall benefit to reducing visibility impacts.

For these reasons combined, the Department maintains that a mass cap ensures a BART level of control overall and potentially a higher level of control at the times of greatest visibility impact.

Table. Comparison of Emission Levels and Control Required in Meeting the 12 Month Mass Cap.

	SO2 Emissions		NOx Emissions	
12 Month Rolling Mass Cap (tons) =	**2,340**		**977**	
Annual Emissions Case During 2002 - 2010	Tons	Required Reduction from Mass Cap	Tons	Required Reduction from Mass Cap
Baseline Year Avg	12,644	81%	3,510	72%
Lowest Actual	11,406	79%	3,273	70%
Highest Actual	13,125	82%	3,656	73%
2010 Actual	12,420	81%	3,406	71%
Low Heat Input	10,731	78%	3,338	71%
High Heat Input	13,262	82%	3,680	73%



Comment 5.2: U.S. EPA commented that averaging emissions over extended periods, 30 day and 12 month periods, allows for more stringent emission limits. It is inappropriate to allow a 30 day emission limit which is less stringent the BART level of control and increased averaging periods typically allow for more stringent emission requirements.

Response: The control levels used in evaluating BART control options are based on long term average reduction levels and not maximum design levels. Further, in several cases compliance margins are appropriate for ensuring long term performance and appropriate compliance requirements (refer to comment 5.3 for discussion of compliance margins). In calculating emission requirements the control efficiencies are then placed against the activity level consistent with that averaging period. This maintains the stringency of the requirement for each averaging period. Therefore the approach used by the Department in identifying control levels and evaluating control equipment options is consistent with setting emission limits over 30 day and 12 month averaging periods.

Also in considering emissions averaging periods, the requirement must be measured against the targeted purpose in determining if it reflects BART control levels. For Georgia Pacific the emission limits are specifically structured to reduce visibility impacts at the most critical time (30 day limit) while achieving BART control level on an overall basis (12 month). The 30 day rolling mass caps are set to protect visibility at times of maximum operation. With the annual mass cap requirement in place the stack S10 boiler system cannot be operated for any duration at the level of the 30 day rolling mass cap. The table below shows the 12 month rolling mass caps prorated to 30 days. Clearly the 12 month requirement is the short-term and long-term driver for overall continuous control levels. The 30 day allowable emissions sets at a maximum control level that is less than could occur if the operated at maximum capacity even while continuously operating BART control equipment. For these reasons the two limitations together ensure the implementation of a BART level of control and visibility improvement at the most critical times below that which would occur based on an emission rate limitation approach.

Comparison of Mass Cap Requirements on a 30 Day Basis.

	12 month rolling mass cap	12 month mass cap prorated to 30 days	30 day rolling mass cap
SO_2 (tons)	2,340	192	268
NO_x (tons)	977	110	80

Comment 5.3 U.S. EPA questions the use of a compliance margin in determining compliance requirements for several control equipment options. The specific control options are turbosorp flue gas desulfurization and overfire air (OFA) and regenerative selective catalytic reduction (RSCR) as applied to boiler B27. Sierra Club also questions the use of any compliance margin in determining compliance requirements.

Response: The Department maintains that consideration of a compliance margin is appropriate on a case-by-case basis for the specific control equipment. Specifically, if long operating levels are clearly demonstrated by actual emissions data then this information can be translated directly into a final control requirement. However, where there is some variability to final optimal control levels associated with characteristics of each source then some level of compliance margin should be assessed. The Department took this approach in applying a low 2% compliance margin for overfire air installed to boiler B27 based on actual operating data. Similarly, a 2% compliance margin is applied to turbosorp based on variability of actual emissions data. For the RSCR, where actual operating data on similar sources is not available, a higher 5% compliance margin is applied. Another type of case is where some variability may occur in control levels during normal operation of the source.

Applying a compliance margin is appropriate in these identified cases. As Georgia Pacific identified in earlier comment to the Department, the Courts have agreed that emission limits cannot be set at the level of reasonably expected control levels. This invariably sets a requirement with which the source will be out of compliance based on normal variability.

The compliance margins in the identified cases are equally or more restrictive than normally expected compliance margins. U.S. EPA economic incentive program (EIP) guidance discusses a 10% compliance margin as a default assumption in accounting where sources will operate in meeting an emission requirement. Also a 10% compliance margin was applied where appropriate in determining Wisconsin's SIP approved NOx RACT emission requirements. The table below shows the percent overall compliance margin resulting from applying the individual control. In all cases where compliance margins are applied, the overall resulting compliance margins are well below 10%.

Control Technology	Operating Control	Compliance Requirement	Real Compliance Margin
OFA	52%	50%	
RSCR	75%	70%	
OFA/RSCR	88%	85%	3%
Turbosorb	95%	93%	2%

6.0 SO2 and NOx Emissions Averaging and Trading

Comment 6.1: U.S. EPA commented that setting a compliance requirement for stack S10 constitutes emissions averaging over both BART and non-BART boilers. Because the Regional Haze Rule only addresses emissions averaging between boilers subject to BART, emission averaging with non-BART boilers is subject to the Economic Incentive Program (EIP) policy and accordingly must demonstrate an environmental benefit (EB). The U.S. EPA recommends limiting emissions to 10 percent below the level that would be required with unit-by-unit limits.

Response: The Department agrees that the stack S10 compliance requirement is subject to an environmental benefit (EB). The EB is comprised of the mass cap to the stack S10 boiler system including a 10% additional reduction applied to the BART boilers.

The EIP states that a default environmental benefit is the reduction of emissions 10% below that level which would result from directly meeting the applicable standards. The EIP also states that in cases where the source is not in an area needing and lacking an approved attainment demonstration (NALD), the trading program may meet the environmental benefit in a variety of ways including an emissions mass cap for single source trading[3]. Because the Georgia Pacific facility is not in a NALD area the environmental benefit can be met through either the additional 10% reduction or a mass cap.

The Department agrees that setting a compliance requirement for total stack S10 emissions is a form of emissions averaging across the BART and non-BART boilers for each pollutant. Initially the Department proposed that Georgia Pacific could meet BART requirements by demonstrating compliance with only the BART boiler emission rate limits or boiler mass caps. The BART requirements are amended where Georgia Pacific is required to comply with a mass cap limitation applied to all stack S10 boilers. As described in the EIP, a mass cap meets the minimum criteria for a single source emissions trading program. However, an additional 10% reduction is applied to the residual emissions for boilers B26 and B27 after BART controls. This step is taken to meet the State's BART rule trading requirements and in applying a more stringent standard for addressing the increased flexibility allowed via inter-pollutant trading (SO_2 for NOx) under the alternative compliance option. The application of 10% environmental benefit to residual emissions follows the calculations established in the EIP, section 7.3(b).

The EIP considers the mass cap approach an environmental benefit because it eliminates any future growth of emissions from all boilers including those with a BART limitation. Realistically, for Georgia Pacific to fully utilize boiler capacity under the stack S10 system, emission controls will have to exceed those applied in determining the NOx and SO_2 BART requirements. The EIP states that the mass cap also acts to eliminate switching load and emissions to other boilers at a facility.

[3] USEPA, 2001, Improving Air Quality with Economic Incentive Programs, section 4.3 page 51, EPA-452/R-01-001, January 2001.

The Department acknowledges that the mass cap is also a measure which contributes to meeting haze reasonable progress goals (RPG) for this planning period. Therefore an argument may be made that the mass cap should not be counted as an environmental benefit if it is counted as a RPG measure or visa versa. The Department maintains that the mass cap works to meet both requirements. The mass cap implements the 10% added reduction without load switching and acts to limit overall emissions from all boilers towards meeting RPG.

Comment 6.2: U.S. EPA, FLM, and Sierra Club comments assert that a mass cap compliance approach will not ensure continuous operation of BART controls. The concern is that controls will not have to operate at the BART control efficiencies when boilers are operating at low loads.

Response: The Department maintains that a mass cap is a continuous control requirement meeting the test for continuous BART control. First, as previous discussed in response to comment 5.1, the control efficiencies and visibility improvement under a mass cap will be equivalent to or greater than the result of implementing an emission rate requirement for the BART boilers. Second, as discussed here, the EIP policy establishes that a mass cap is an acceptable control approach for emission limit requirements. In fact, the EIP considers a mass cap to constitute an overall environmental benefit compared to an emission rate requirement.

Under the EIP policy, U.S. EPA clearly encourages use of economic incentive programs (emissions averaging, trading, etc...) in meeting Clean Air Act requirements for criteria pollutants. EPA also states that the EIP policy applies to programs used by states in meeting regional haze requirements – as such the EIP policy applies to implementation of BART requirements.[4]

The EIP establishes that a mass cap approach is an appropriate alternative and constitutes an environmental benefit in meeting source specific and continuous emission rate requirements. The test EPA applies is whether a mass cap will result in emission reductions equivalent to those reasonably expected when meeting the emission limitation or operating the control equipment continuously. The best example of this position is where EPA discusses meeting RACT requirements through an EIP program.

> *"Your EIP may allow sources subject to RACT to avoid direct application of RACT technology [ ]. In doing so, it is important to note that these sources are not avoiding the RACT requirements; they are avoiding the direct application of RACT technology. The reductions called for by the RACT requirements are satisfied through other means.[ ] If your EIP allows sources to avoid the direct application of RACT technology, your EIP must ensure that the level of emission*

[4] USEPA, 2001, Improving Air Quality with Economic Incentive Programs, section 1.1 page 4, EPA-452/R-01-001, January 2001.

reductions resulting from the EIP will be equal to those reductions expected from the direct application of RACT"[5]

The Department believes that BART is directly comparable to implementing a RACT technology program under EIP guidance.

7.0 SO2 and NOx Inter-Pollutant Trading

Comment 7.1: U.S. EPA and the Federal Land Managers commented that the Haze Rule may not support inter-pollutant trading of visibility pre-cursors.

Response: The Department maintains that inter-pollutant trading is allowed and supported by the Haze Rule and other EPA policy documents. Further, that no rule provision or Haze Rule supporting document, including the preamble, precludes inter-pollutant emissions trading.

In the basic form, the Haze Rule supports the use of emissions averaging and alternative compliance options. Under 40 CFR Part 51, Appendix Y, section V, U.S. EPA encourages states to allow for emissions averaging on a facility basis:

"You should consider allowing sources to 'average' emissions across any set of BART 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 the BART-eligible source"

This provision clearly addresses the simple case where one pollutant such as NOx is being averaged over multiple boilers at the Georgia Pacific facility. To the other end of the spectrum, the Haze Rule under 40 CFR part 51.308(e)(2) allows for broader multi-facility emissions trading:

"A State may opt to implement an emissions trading program or alternative measure rather than to require sources subject to BART to install, operate, and maintain BART. To do so, the State must demonstrate that this emissions trading program or other alternative measure will achieve greater reasonable than would be achieved through the installation and operation of BART."

This provision describes a program which can be implemented over the entire state and can encompass all sources within one or multiple source categories. The primary emission requirement of this provision is that any trading program will achieve greater reasonable progress in visibility improvement versus meeting BART alone for the affected Class I areas. EPA further indicates that visibility improvement should be tested for the worst and best 20 percent of days if the geographic distribution of

[5] USEPA, 2001, Improving Air Quality with Economic Incentive Programs, section 16.7 page 239, EPA-452/R-01-001, January 2001.

emissions is significantly different than under BART. This modeling would demonstrate "greater reasonable progress" if two criteria are met:

1) Visibility does not decline in any Class I area.
2) There is an overall improvement in visibility, determined by comparing the average differences between BART and the alternative over all Class I areas.

The Department believes that inter-pollutant trading represents a significant difference in the distribution of emissions and therefore subject to these methods for evaluating visibility. However, the main point to consider is that none of the Haze Rule trading or alternative option criteria directly state or infer a restriction of inter-pollutant visibility precursor pollutants. In the contrary, the criteria specifically point to testing overall visibility improvement only. Further, the overall provision allows for a trading program with significant flexibilities and inherently significant variability in visibility impacts at any one time or place. The Department believes that the Georgia Pacific inter-pollutant trading / alternative compliance option falls between single pollutant emissions averaging and the broad trading program allowed under the Haze Rule. Once again at minimum, the Haze Rule does not prohibit inter-pollutant trading co

The Department believes the U.S. EPA policies for economic incentive programs (EIP) and new source emission offsets for particulate matter support the inter-pollutant program proposed for Georgia Pacific. Under the EIP policy, EPA encourages the use of emissions averaging and trading where it is not otherwise prohibited or addressed through the specific applicable pollutant rule. The EIP also specifically states that the guidance applies to haze regulations[6]. Lastly, the EIP establishes that inter-pollutant trading of precursor emissions is allowable[7]. The policy is developed with ozone precursor trading (NOx and VOC) as the example. Since ozone is regulated to primarily address health related impacts this example seems to set the most stringent criteria for trading. The Department believes that meeting this ozone trading criteria meets all possible constraints of inter-pollutant trading, outside of the haze rule, for pollutants regulated for visibility and haze impacts. The EIP indicates in this case that air quality modeling must be conducted to establish the correct ratio for inter-precursor trades of ozone. Such an analysis and resulting trading ratio has been established for the Georgia Pacific inter-pollutant trading / alternative compliance option.

The U.S. EPA established that inter-pollutant trading is appropriate in netting PM2.5 offsets for new source review (NSR) requirements[8]. The guidance directly addresses trading SO_2 and NOx as precursors for PM2.5 which clearly establishes that EPA supports inter-pollutant precursor trading for the same pollutants and particulate outcomes which affect visibility. EPA in establishing this policy provided the expected

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[6] USEPA, 2001, Improving Air Quality with Economic Incentive Programs, section 1.1 page 4, EPA-452/R-01-001, January 2001.
[7] USEPA, 2001, Improving Air Quality with Economic Incentive Programs, sections 6.2, page 82 and 16.9 page 243, EPA-452/R-01-001, January 2001.
[8] U.S. EPA, 2011, *Revised Policy to Address Reconsideration of Interpollutant Trading Provisions Fine Particles (PM2.5), July 21, 2011,* http://www.epa.gov/region07/air/nsr/nsrmemos/pm25trade.pdf.

methodology for developing inter-pollutant precursor trading based air quality modeling for a specific geographic area and then establishing pollutant trading ratios. The Department believes the approach used in establishing inter-pollutant trading for Georgia Pacific follows the same methodology outlined by the U.S. EPA for PM2.5 inter-pollutant trading.

In conclusion, the Department finds that the exchange of visibility precursor emissions through either an inter-pollutant trading program or alternative compliance option is allowed and supported for Georgia Pacific in meeting BART requirements. The program must, however, meet all applicable criteria under the haze rule and EIP policy. As discussed in response to comments the Department believes all EIP criteria are met.

Comment 7.2: U.S. EPA questions whether any inter-pollutant alternative compliance option can allow levels of SO_2 and NOx to vary over time; i.e. can Georgia Pacific change the amount of SO_2 excess emissions traded in lieu of NOx reductions anytime into the future.

Response: The Department believes varying SO_2 and NOx levels according to constraints which ensure greater visibility improvement than BART is allowable. However, the proposed alternative compliance option has been amended such that traded emissions will be chosen and fixed into the future. The Department does request, however, that U.S. EPA consider allowing an inter-pollutant trading program which allows varying SO_2 and NOx emission levels tied to the BART mass caps based on a 2:1 trading ratio.

Comment 7.3: U.S. EPA commented that the proposed inter-pollutant trading option needs to account for future SO2 requirements because the EIP policy requires emission reductions used for emissions averaging or trading to be "surplus" to other federal requirements.

Response: The Haze Rule specifically identifies "surplus" reductions under 40 CFR part 52.308(e)(2)(iv) for purposes of a BART emissions trading program or alternative compliance option. The provision states:

> *"emission reductions resulting from the emissions trading program or other alternative measure will be surplus to those reductions resulting from measures adopted to meet requirements of the CAA as of the baseline date of the SIP."*

In the case of the Haze Rule and BART the "baseline date of the SIP" is the BART baseline years 2002 to 2003.

The Departments understanding of the EIP guidance is that it does not supercede specific requirements or criteria specifically addressed by another regulation. Therefore emission requirements effective after this time and into the future do not affect the identification of "surplus" emissions for purposes of BART. Because the BART requirements will reduce both SO_2 and NOx to levels below any previous requirement, including those implemented since the baseline years, the BART mass caps for each pollutant set the basis for determining surplus emissions for purposes of the BART alternative compliance option. The Departments understanding is that this basis will not change into the future based on surplus being defined under the Haze Rule instead of the EIP policy. A fixed basis for counting surplus emissions is similar to what occurs under the federally implemented programs such as CAIR and CSAPR.

Comment 7.4: The concern of whether continuous BART control under a mass cap will be achieved is further extended to inter-pollutant compliance option where SO_2 can be traded for NOx. Basically, there is concern that SO_2 reductions can be generated such that all NOx reduction can be avoided.

Response: The Department believes that the test for a BART inter-pollutant trading program is whether it achieves equivalent visibility improvement whereas SO_2 and NOx are both visibility precursors. Therefore under the Haze rule, the measure of continuous BART control is not the net tons reduction of either SO_2 or NOx but rather the continuous level of visibility improvement. The Department's analysis shows that a preferred alternative for the greatest visibility improvement is to allow minimal NOx reductions in lieu of greater SO_2 reductions at a trading ratio of 2 $SO_2$2 for 1 NOx (refer to comment 7.6).

However, the Department acknowledges the NOx emission reductions have direct visibility improvement and for any one day the best visibility improvement may be obtained through reducing both NOx and SO_2 emissions together. Therefore, the alternate compliance option based on inter-pollutant trading includes a minimum NOx emission reduction requirement. Accordingly, a NOx emission cap of 1,522 tons on a 12-month rolling basis and 172 tons on a 30-day rolling basis applies to the stack S10 system. The mass cap level corresponds to approximately 50% reduction of NOx compared to the average baseline year emissions

7.5 Comment: U.S. EPA questions the validity of modeling versus baseline year emissions because it does not account for emission reductions from future regulations and resulting atmospheric chemistry conditions.

Response: The Department believes modeling future unknown regulations for evaluating BART or BART alternative compliance options is not appropriate. The Haze Rule clearly identifies the BART baseline years of 2002 to 2004 as the basis for evaluating BART controls and visibility impacts. Further, in providing for alternative compliance options the Haze Rule, 40 CFR part 51.308(e)(2)(iv) establishes that excess emissions are to be determined based on regulations or requirements in place during the BART baseline years. This further supports that BART is a determination made in time which carries forward as is. The requirements do not alter due to other regulations. Rather if further emission reductions are needed for visibility improvement this issue is addressed in meeting each step of Reasonable Progress Goals (RPG).

In direct response to this comment the Department has found, based on visibility modeling for evaluated control options, as emissions are removed from the atmosphere the average visibility improvement from BART controls will increase. The Department has not identified a scenario where future regulations and the finalized BART requirements will result in a negative visibility impact versus the BART level of visibility improvement.

7.6 Comment: U.S. EPA commented that a trading ratio of 2.2:1 (SO_2:NOx) is reflected in the analysis of visibility equivalency supporting inter-pollutant trading.

Response: The Department acknowledges an actual trading ratio of 2.2 tons SO_2 to 1 ton was modeled in establishing the inter-pollutant compliance option. This slightly higher ratio was an inherent result of the modeling data preparation. Even with this difference the Department maintains, based on information discussed below, that a trading ratio of 2 SO_2 for 1 NOx is appropriate for inter-pollutant compliance alternatives at the Georgia Pacific facility. However to support this ratio the Department is conducting visibility modeling for the finalized BART compliance requirements and trading SO_2 for NOx in a 2:1 ratio. The results will be submitted to U.S. EPA as supplemental support information the Haze SIP submittal.

The 2:1 trading ratio is supported by existing modeling results by assessing the visibility impact of the 0.2 ratio differential. To do this, the incremental visibility is first interpolated based on the results for the model results at trading ratios of 1.1, 2.2, and 3.3 SO_2 to 1 NOx. These results were initially presented in Table 7.4 of the July 2011 draft BART determination as Cases 2, 4, and 6, respectively. From this data, as shown in the table below, the 0.2 ratio differential results in an impact of 0.02 to 0.053 deciview based on visibility change between the 1.1 to 2.2 SO2 trading ratios. In similar fashion, the visibility impact 0.2 ton ranges from 0.016 to 0.027 deciviews based on the change in visibility between the 2.2 to 3.3 ratios. The Department acknowledges the visibility impact is not perfectly linear across the trading ratios. However, looking at this full range of 1.1. to 3.3 ratios inherently captures how the visibility may change with each ton of trade.

These deciview impact of 0.2 tons SO_2 can then be added to the total visibility impact result for the 2.2 SO_2 trading ratio. This calculation results in the adjusted visibility impact of trading at the 2.0 SO_2 to 1.0 NOx ratio. As can be seen these adjusted values do not exceed the visibility impact for the BART mass caps (w 10% environmental benefit). Therefore the Department believes a 2:1 SO_2 to NOx trading ratio is supported for the Georgia Pacific alternative compliance option.

Trading Ratio Case		Maximum Deciview Impact		
		2002	2003	2004
BART		***2.56***	***1.33***	***2.14***
Trading Ratio Adjustment	1.1:1	2.8	1.32	2.15
	2.2:1	2.51	1.21	1.98
	1.1 Ratio Incerment	0.29	0.11	0.17
	0.2 Ratio	0.053	0.020	0.031
	Adjusted 2:1	***2.56***	***1.23***	***2.01***
Trading Ratio Adjustment	2.2:1	2.51	1.21	1.98
	3.3:1	2.35	1.12	1.83
	1.1 Ratio Incerment	0.16	0.09	0.15
	0.2 Ratio	0.029	0.016	0.027
	Adjusted 2:1	***2.54***	***1.23***	***2.01***

7.7 Comment: Georgia Pacific commented that because the trading plan is not BART, compliance for the trading plan option should be Dec. 31, 2017 instead of the Dec. 31, 2015 date for BART.

Response: WDNR maintains that compliance with BART is Dec. 31, 2015, even under a trading plan.

8.0 Compliance Requirements

Comment 8.1: U.S. EPA commented that the Georgia-Pacific BART requirements must be established in a permanent enforceable document.

Response: The Department agrees. The Georgia Pacific BART requirements are to be established in a permanent administrative order. The Department commits to, once the contents of the order proposed in this submittal are approved, to submit the finalized signed administrative order to U.S. EPA for inclusion to the Haze SIP.

II. Electric Generating Unit (EGU) BART Requirements

Comment: The National Parks Service commented that Department can either show that the proposed BART emission rate limits for the EGUs modeled at maximum actual emissions for PM_{10} have no significant impact on visibility, or propose limits that reflect the capability of existing controls.

Response: The EGUs must implement the Utility MACT emission limitations, finalized by EPA in November 2011. The Utility MACT is expected to lower PM_{10} emission limits to below 0.03 Lb/mmBtu by 2015. Combined with the minimal visibility impact at the permit emission limits, the Department maintains that no additional emission limitation for PM_{10} is necessary.

Appendix A

Determination of CAIR Applicability Boiler B25
Georgia Pacific Broadway Mill

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
WASHINGTON, D.C. 20460

MAY 25 2011

OFFICE OF
AIR AND RADIATION

Kelly L. Wolff
Vice President - Manufacturing
Georgia Pacific Corporation
Green Bay Operations
1919 South Broadway
P.O. Box 19130
Green Bay, WI 54307-9130

Re: CAIR Applicability Determination for Georgia Pacific Corporation, Broadway Paper Mill, Boiler B25 located in Green Bay, Wisconsin

Dear Mr. Wolff:

This letter is EPA's determination of applicability under the EPA-administered trading programs under the Clean Air Interstate Rule (CAIR) and the CAIR Federal Implementation Plans (FIPs), for Georgia Pacific Corporation's (Georgia Pacific) Broadway Paper Mill Boiler B25 in Green Bay, Wisconsin.[1] This applicability determination is in response to Georgia Pacific's June 1, 2007 request for an applicability determination for Boiler B25 under the CAIR trading programs and supplemental information provided by Georgia Pacific on August 23, October 18, and November 1, 2007, February 13, April 4, and June 24, 2008, December 11, 2009, and March 23, April 22, and November 23, 2010 and February 4, 2011.[2]

Background

Under the CAIR trading programs for NOx annual and ozone season and SO_2 emissions, a unit that is a "stationary, fossil-fuel-fired boiler or a stationary, fossil-fuel-fired combustion turbine serving at any time, since the later of November 15, 1990 or the start-up of the unit's combustion chamber, a generator with nameplate capacity of more than 25 MWe producing electricity for sale" is generally a CAIR NOx, CAIR SO_2, and CAIR NOx Ozone Season unit subject to the requirements of the trading programs. 40 CFR 97.104(a) (1), 97.204(a) (1), and

[1] On October 16, 2007, EPA approved Wisconsin's State Implementation Plan (SIP) in part and disapproved in part. 72 Fed. Reg. 58542 (Oct. 16, 2007). By its approval of the SIP as an abbreviated SIP, EPA approved the methodology to be used to allocate NOx annual and ozone season allowances under the CAIR FIPs, except for allowances in the compliance supplement pool. The CAIR FIPs, with these approved modifications, are applicable to Wisconsin sources.

[2] Georgia Pacific also submitted several petitions under 40 CFR 97.175 and 97.375 requesting extensions of time for meeting the requirements, under the CAIR FIPs, that Georgia Pacific install and certify continuous emission monitoring systems (CEMS) at Boiler 25. EPA's latest approval of such a petition was on September 30, 2010.

97.304(a) (1). However, certain units meeting these criteria are exempt from being CAIR NOx, CAIR SO_2, or CAIR NOx Ozone Season units. For example, any unit meeting the following criteria is exempt from the CAIR trading programs:

> (A) Qualifying as a cogeneration unit during the 12-month period starting on the date the unit first produces electricity and continuing to qualify as a cogeneration unit; and
>
> (B) Not serving at any time, since the later of November 15, 1990 or the start-up of the unit's combustion chamber, a generator with nameplate capacity of more than 25 MWe supplying in any calendar year more than one-third of the unit's potential electric output capacity or 219,000 MWh, whichever is greater, to any utility power distribution system for sale.

40 CFR 97.104(b)(1)(i), 97.204(b)(1)(i), and 97.304(b)(1)(i). (These provisions are generally referred to as the "cogeneration unit" exemption.)

Under CAIR a cogeneration unit is defined as:

> a stationary, fossil-fuel-fired boiler or stationary, fossil-fuel-fired combustion turbine:
>
> (1) Having equipment used to produce electricity and useful thermal energy for industrial or commercial, heating, or cooling purposes through the sequential use of energy; and
>
> (2) Producing during the 12-month period starting on the date the unit first produces electricity and during any calendar year after the calendar year in which the unit first produces electricity –
>
> (i) For a topping-cycle cogeneration unit,
>
> (A) Useful thermal energy not less than 5 percent of total energy output; and
>
> (B) Useful power that, when added to one-half of useful thermal energy produced, is not less then 42.5 percent of total energy input, if useful thermal energy produced is 15 percent or more of total energy output, or not less than 45 percent of total energy input, if useful thermal energy produced is less than 15 percent of total energy output.
>
> (ii) For a bottoming-cycle cogeneration unit, useful power not less than 45 percent of total energy input;
>
> (3) Provided that the total energy input under paragraphs (2)(i)(B) and (2)(ii) of this definition shall equal the unit's total energy input from all fuel except biomass if the unit is a boiler.

<u>See</u> 40 CFR 97.102, 97.202, and 97.302 (definition of "cogeneration unit").

Georgia Pacific operates five coal-fired boilers at the Broadway Paper Mill, Boilers B25, B26, B27, B28, and B29 with maximum design heat input capacities of 200 mmBtu/hr, 350 mmBtu/hr, 615 mmBtu/hr, 250 mmBtu/hr, and 486 mmBtu/hr respectively. These boilers provide steam to a common header, which distributes steam (at 400 psi) to the mill processes and to five steam turbine/ generator combinations with nameplate capacities of 10.0, 17.3, 18.7, 28.9, 43.2, and 28.2 MWe respectively, from which steam is drawn at several different points and pressures (e.g., at 35, 135, and 400 psi) and distributed to the mill for processes and heating and which produce electricity. See August 23, 2007, June 24, 2008, December 11, 2009, and November 23, 2010 supplemental information. According to Georgia-Pacific, the Broadway Paper Mill initially used its on-site boilers to produce only steam and met all on-site processing and heating needs but, since at least 1954, used some of the steam to generate electricity, as well, for on-site use. Since at least 1980, on-site boilers have met all of the mill's steam and electricity needs. See November 23, 2010 supplemental information (response 1). In 1990, the mill began supplying some of the generated electricity for sale, through a 10,000 kW tie line, to a utility distribution system, i.e., a portion of an electricity grid owned or operated by a utility (Wisconsin Public Service Corporation). The capacity of the tie line was increased to 25,000 kW in 1999. See id. (response 2); and 40 CFR 97.102, 97.202, and 97.302 (definition of "utility power distribution system").

According to Georgia Pacific, each of the five boilers produces electricity and useful thermal energy for industrial purposes through sequential use of energy and is a topping-cycle unit. See 40 CFR 97.102, 97.202, and 97.302 (definitions of "cogeneration unit" and "topping cycle cogeneration unit"). Further, Georgia Pacific asserted that the overall efficiency of the system of on-site boilers and steam turbine/generators (all of which are on a common steam header) meets the efficiency requirement, and that the system and each individual boiler meet the sales limitation requirement, for the exemption from the CAIR trading programs for cogeneration units under 40 CFR 97.104(b)(1)(i), 97.204(b)(1)(i), and 97.304(b)(1)(i).

Georgia Pacific provided calculations for 2005 through 2009 that used the steam contribution (in mmBtus) measured at each of the five boilers as a percentage of total steam contribution by the group of all five boilers to apportion to each individual boiler the total useful power and total useful thermal energy produced by the system (i.e., five boilers serving five steam turbine/generators). In its calculations, Georgia Pacific also used fuel sampling data on the heat input per ton for the types of coal combusted in the boilers and data on the tons of coal combusted in each boiler to calculate annual energy input for each boiler. Georgia Pacific then calculated annual efficiency for each individual boiler by adding the useful power produced to one-half of the useful thermal energy produced and dividing the result by the energy input. Based on this calculation, all the boilers except Boiler B25 met the efficiency requirement for the cogeneration unit exemption. Georgia Pacific also calculated annual efficiency for the entire system by adding total useful power produced by the system to one-half of total useful thermal energy produced by the system and dividing the result by total energy input for the system. Based on that calculation, the entire system, and thus all five boilers in the system, met the efficiency requirement. See August 23, 2007 and April 22, 2010 supplemental information.

According to Georgia Pacific, calculating the efficiency of each boiler or the efficiency of the system requires the calculation of useful thermal energy produced, which, in turn, requires data on the amounts and pressure of the steam provided from the boilers and the steam turbine/ generators for mill processing and heating. Georgia Pacific stated that it does not have data on steam drawn before 2005 from the steam turbine/generators and that therefore it is unable to produce even "reasonable estimates" of the efficiency of the boilers before 2005. March 23, 2010 supplemental information; see also November 23, 2010 supplemental information. According Georgia-Pacific, the total amount of useful thermal energy provided from the boilers and steam turbine/generators was higher before 2005 because of steam reduction projects that starting in 2005 reduced the steam processing needs of the mill. Id.

Georgia Pacific requested that, using one of the following approaches, EPA determine that Boiler B25 is not subject to the CAIR trading programs:

1) Approve use of the overall annual efficiency of the system at the Broadway Paper Mill, comprising all five boilers on a common steam header that serves five turbine/generator combinations and supplies process steam, to determine whether Boiler B25 and the other boilers qualify for the exemption for cogeneration units under the CAIR trading programs; or

2) Establishing, and applying to Boiler B25, a new exemption from the CAIR trading programs for boilers serving a common header that are incapable of individually providing enough steam to a steam turbine/generator combination to generate at least 25 MWe without additional steam from some other unit or source.[3]

EPA's Determination

As discussed above, according to Georgia Pacific, each of the five boilers at the Broadway Paper Mill serves at least one generator with a nameplate capacity greater than 25 MWe producing electricity for sale. Each boiler is therefore subject to the CAIR trading programs unless it qualifies for the cogeneration unit exemption. See 40 CFR 97.104(a)(1) and (b)(1)(i), 97.204(a)(1) and (b)(1)(i), and 97.304(a)(1) and (b)(1)(i). As discussed above, in order to be a cogeneration unit, each boiler must -- during the 12-month period starting on the date the boiler first produces electricity and thereafter -- have the equipment to produce electricity, and useful thermal energy for industrial or commercial, heating, or cooling purposes, through sequential use of energy. Further, because each boiler is a topping-cycle unit in that it produces first electricity and then useful thermal energy[4], the remaining requirements for qualification for

[3] In its request, Georgia Pacific only requested a determination of applicability of the CAIR NOx annual and NOx ozone season trading programs, ostensibly because the initial control periods for these programs are in 2009 while the initial control period for the CAIR SO_2 trading program is in 2010. However, the applicability provisions relevant to Boiler 25, and the provisions for cogeneration units in particular, are identical in all three trading programs. Accordingly, if a unit qualifies for the exemption for certain cogeneration units under any of these trading programs, the unit qualifies for the exemption under all three trading programs. EPA is therefore extending, sua sponte, its applicability determination for Boiler 25 to cover all three CAIR trading programs.

the cogeneration unit exemption concerning the five boilers are that: (i) during the 12-month period starting on the date the boiler first produced electricity and each calendar year thereafter, useful thermal energy equal not less than 5 percent of total energy output and useful power that, when added to one-half of useful thermal energy produced, equal not less than 42.5 percent of total energy input; and (ii) starting November 15, 1990, the generators served by the boilers not produce more than one-third of the unit's potential electric output capacity or 219,000 MWh, whichever is greater, to any utility power distribution system for sale.

EPA determines that -- based on boiler performance data for 2005 through 2009 and electricity sales data from 1999 through 2009 and conditioned on the accuracy and completeness of certain assumptions about boiler performance before 2005 -- Boiler B25 qualifies for the cogeneration unit exemption, and is not covered by the CAIR trading programs, up through 2009. Further, EPA concludes that a new exemption (i.e., for any boiler that cannot produce enough steam to generate more than 25 MWe without additional steam from another unit) from the CAIR trading programs cannot be established, through this applicability determination.

A. Cogeneration Unit Exemption

As discussed above, in order to be a cogeneration unit, a unit must be fossil-fuel-fired and -- during the 12-month period starting on the date the unit first produces electricity and thereafter -- have the equipment to produce electricity, and useful thermal energy for industrial or commercial, heating, or cooling purposes, through sequential use of energy. Georgia Pacific stated that it believes that each of the boilers at the Broadway Paper Mill was designed for cogeneration and has been consistently used as a cogeneration unit since installation of the steamturbine/ generators in to order provide steam and electricity for the mill. See November 23, 2010 supplemental information (response 5).

Moreover, EPA's requirement that a unit has equipment to produce electricity and useful thermal energy using sequential use of energy is analogous to the sequential-use-of-energy requirement in the definition of "cogeneration facility" adopted by the Federal Energy Regulatory Commission (FERC) and reflected in FERC's decisions about whether facilities are "qualifying cogeneration facilities". Compare 40 CFR 97.102, 97.202, and 97.302 (paragraph (2)(k) for the definition of "cogeneration unit") with 18 CFR 292.202(c) (definition of "cogeneration facility). Applying the same criterion as EPA of sequential use of energy to produce electricity and useful thermal energy (as well as other ownership, operating, and efficiency requirements), FERC approved certification of the Broadway mill (then owned by Fort Howard Corporation) as a qualifying cogeneration facility on June 8, 1990. See Fort Howard Corp., Small Power Production and Cogeneration Facilities -- Qualifying Status, 51 FERC ¶62,223 (Je. 8, 1990) (holding that the mill, then comprising 6 boilers and 9 steam turbine/generators, was a "topping-cycle cogeneration facility"). There is no indication that this certification was ever subsequently terminated. For the period before the issuance of FERC's certification approval, EPA assumes, based on the information provided by Georgia Pacific and

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[4] See 40 CFR 97.102, 97.202, and 97.302 (definitions of "topping cycle cogeneration unit").

solely for purposes of this determination, that each boiler at the Broadway Paper Mill has consistently operated as a cogeneration unit since the boiler's commencement of electricity generation up to the issuance date of the FERC approval.

In addition, a unit that is a topping-cycle unit, like Boiler B25, must -- during the 12-month period starting on the date the unit first produces electricity and each calendar year thereafter -- meet the requirement of producing useful thermal energy equal to not less than 5 percent of total energy output and producing useful power that, when added to one-half of useful thermal energy produced, equal at least 42.5 percent of total energy input.

Georgia Pacific provided data for 2005 through 2009, during which period all five boilers operated, except for Boiler B25 in 2009. That data indicated that, for each year, both the system (including five boilers and five turbine/generator combinations) and each boiler alone -- except Boiler B25 in 2009 -- produced useful thermal energy well in excess of the minimum of 5 percent of total energy output, i.e., ranging from 49.1 to 53.9 % on a system wide basis and from 48.8 to 56.7 % on an individual-boiler basis. The data also indicated that, for each year, the system produced useful power that, when added to one-half of useful thermal energy produced by the system, was in excess of the minimum of 42.5 percent of total energy input for the system, i.e., ranging from 47.4 % to 48.4 %. Further, the data showed that Boiler B25 alone did not meet this latter efficiency requirement on an individual-boiler basis, having an efficiency of 36 % for 2005, 34.1 % for 2006, 37.1 % for 2007, and 35.2% for 2008 and no efficiency percentage value for 2009, when the unit did not operate. <u>See</u> August 23, 2007 and April 22, 2010 supplemental information.

EPA has reviewed Georgia Pacific's efficiency calculations for the units at the Broadway Paper Mill. Based on this review, EPA finds that, given the configuration and operational conditions unique to the Broadway Paper Mill, i.e., where five boilers feed five turbine/generators through a common header, one boiler is used as a swing boiler to reduce the effects of variability of load and capacity availability on the other boilers, process steam is extracted from the common header and from the five turbines, and the turbines power five electricity generators, it is not feasible to calculate, with any reasonable accuracy, the individual boiler efficiencies for this facility.

The accuracy of the efficiency calculation for Boiler B25 depends on the ability to accurately calculate the efficiency of that boiler separately from the efficiency of the other boilers in the system. As explained by Georgia Pacific, Boilers B27 and B29 are used as base load units for steam demand at the Broadway Mill, and the use of Boilers B26 and B28 is adjusted to follow steam demand. However, Boiler B25 is the first boiler whose use is adjusted to steam demand changes and boiler maintenance outages, i.e., is used as a swing boiler to address variability in steam demand and availability of steam production capacity. In those circumstances, Boiler B25 is used in lieu of or before starting up one of the other larger boilers. Between scheduled outages in the spring, Boiler B25 is generally kept in operation to avoid mechanical problems associated with cycling the boiler. The net result of this type of boiler use is that Boiler B25 has more frequent startups and shutdowns, and shorter run periods, than the other boilers. See July 1, 2007 request; and June 24, 2008 supplemental information. Because a boiler tends to be less efficient during startup and shutdown and more efficient when operating for periods of time at a relatively constant load, Boiler B25's calculated efficiency is lower than that of the other boilers in the system, but, by operating in this less efficient mode, Boiler 25 enables the other boilers generally to operate more efficiently.[5] Id.; see also Wayne, C. Turner, Energy Management Handbook at 109 (5th ed. 2005) (explaining that "boilers generally operate most efficiently at 65 to 85% full-load rating", "[n]ewer units and units with higher capacity are generally more efficient than are older, smaller units", and "[g]enerally, steam plant load swings should be taken in the smallest and least efficient unit"). In short, calculating the efficiency of Boiler B25 alone ignores the effect of Boiler B25 on the efficiency of the other boilers and thereby effectively understates the efficiency that results from operating Boiler B25.

For this reason, EPA finds that it is not feasible to calculate, with any reasonable accuracy, the individual boiler efficiencies for this facility and that, for 2005 through 2009, all five boilers, viewed together, met the efficiency requirements for cogeneration units. Georgia Pacific stated that it believes that the boilers were operated in essentially the same manner before 2005 (i.e., as cogeneration units for providing steam and heating, and, starting at least in 1984, electricity, for the mill) as during and after 2005. See November 23, 2010 supplemental information (response 5). Under these circumstances, with regard to each year from boiler start-up through 2004, EPA assumes, solely for purposes of this determination, that the boilers at the Broadway Paper Mill have been operated in generally the same manner as they are currently operated and that the boilers, viewed together, have met the efficiency and operating requirements for a cogeneration unit. See 40 CFR 97.102, 97.202, and 97.302 (setting forth, paragraphs (2)(i)(A) and (B), standards for topping-cycle units in definition of "cogeneration unit").

In addition, EPA finds that the electricity sales limit applicable to Boiler B25 in order to qualify for the cogeneration unit exemption is 219,000 MWh because that figure is higher than one-third of the unit's potential electric output capacity. Based on Boiler B25's maximum design heat input of 200 mmBtu/hr, one-third of the unit's potential electric output capacity is 56,940 MWh,[6] which is not greater than 219,000 MWh. Georgia Pacific explained that, until

[5] However, the full impact of Boiler B25 on the other boilers' efficiency is somewhat more complex. According to Georgia Pacific, when Boiler B25 is used instead of increasing load at Boilers B26 and B28, the load, and thus the efficiency, of the latter two boilers at those times is somewhat lower. See June 24 supplemental information. Determining the efficiency of all five boilers together allows for such efficiency interactions to be reflected in the efficiency determination.

[6] Potential electrical output capacity for a unit is calculated by dividing the maximum design heat input capacity in Btu/hr of the unit by 3 (reflecting the assumed efficiency of the unit), dividing again by 3,413 (reflecting the assumed heat rate), dividing again by 1,000 (converting to MWe), and multiplying by 8,760 (hours per year). See 40 CFR 97.102, 97.202, and 97.302 (definition of "potential electrical output capacity").

1999, the Broadway Paper Mill had a 10,000 kW utility tie line, which, even if used every hour to its maximum capacity, could not carry more than about 88,000 KWh per year. While the utility tie line capacity was increased to 25,000 kW in 1999, Georgia Pacific provided data on electricity sales for the Broadway Paper Mill for 1999 through 2009. According to Georgia Pacific, total annual electricity sold during 1999 through 2009 never exceeded 219,000 MWh and generally was significantly lower, ranging from less than 1% to about 21 %. November 23, 2010 supplemental information. Boiler B25's proportional share of the total annual electricity generation by the five generators was, of course, less than the total generation sold by the facility and comprised an even lower percentage of the 219,000 MWe sales limit.[7]

EPA therefore concludes that, up through 2009 and conditioned on the accuracy of the assumptions about the Broadway Paper Mill's boiler operation before June 8, 1990, Boiler B25 at Georgia Pacific's Broadway Paper Mill qualifies as a cogeneration unit and meets the requirements for the cogeneration unit exemption from the CAIR trading programs. Because EPA has no data on operations and electricity sales for the Broadway Paper Mill for 2010 and later, EPA is not determining whether Boiler B25 is exempt for any year after 2009.

B. Exemption for Low Capacity Boilers

Georgia Pacific requested that EPA consider alternate rule language exempting small boilers that are incapable of providing enough steam on their own to support a 25 MWe steam turbine/generator combination (Georgia Pacific's method 2). EPA rejects this argument because 40 CFR 97.104, 97.204, and 97.304 specifically state that CAIR applies to fossil-fuel fired boilers that serve a generator over 25 MWe are CAIR units. The CAIR applicability provisions do not differentiate between single boilers or groups of boilers serving the generator over 25 MWe nor do they make any distinctions based on the boiler capacity or steam output.

Further, EPA considers Georgia Pacific's argument as a request that the Agency amend the CAIR FIP, to create a new exemption from the CAIR requirements. First, EPA promulgated the CAIR FIP as a final rule on April 28, 2006, after providing public hearing and opportunity for submission of comments, as a final rule on April 28, 2006. EPA cannot, in the context of applying the applicability provisions of the EPA-administered trading programs (including the CAIR FIP trading programs) amend the applicability provisions of the CAIR FIP to create new exemptions. The time for parties to request new exemptions was during the rulemaking process for the CAIR FIP, thus affording all interested parties where parties requesting or opposing new exemptions would have had the opportunity to comment.

[7] In applying the electricity sales limit, EPA interprets the limit as applying to the total amount of electricity produced by all generators served by the unit -- whether the unit serves one generator or multiple generators -- and attributable to the steam produced by the unit for such generators. Otherwise, a unit providing steam to multiple generators would have a different electricity sales limit than a unit with the same maximum design heat input capacity providing the same amount of steam but to only one generator.

Second, under CAIR, a State that wants to participate in the EPA-administered trading programs must adopt rules that -- except for a few, allowed differences -- are substantively identical to the CAIR model rules. Those model rules include the applicability provisions (in 40 CFR 96.104, 96.204, and 96.304) that lack an exemption for non-cogeneration units based on unit size. See, 40 CFR 51.123(o)(2) and (aa)(2) and 51.124(o)(2). The differences that States participating in the EPA-administered trading programs are allowed to adopt in CAIR SIPs do not include the creation of small unit exemptions from the applicability provisions. See 40 CFR 51.123(o)(2) and (aa)(2) and 51.124(o)(2). Therefore, under CAIR, Wisconsin cannot create a new small unit exemption through a CAIR SIP revision and still participate in the EPA-administered trading programs.

NODA Objection

On August 4, 2006, EPA published a Notice of Data Availability for EGU NOx Annual and NOx Ozone Season Allocations for the Clean Air Interstate Rule Federal Implementation Plan Trading Programs (NODA) (71 FR 44283 (Aug. 4, 2006)). The NODA did not provide any allowance allocations for Boiler 25. Georgia Pacific stated that it objected to the lack of allocations if EPA determined that the unit was subject to the CAIR trading programs. Because EPA has determined that Boiler B25 meets the cogeneration unit exemption up through 2009 for reasons explained above, Georgia Pacific's objection to the NODA is moot.

Conclusion

- EPA's determination is conditioned on the above-described assumptions about the Broadway Paper Mill's boiler operation and relies on the accuracy and completeness of the information provided by Georgia Pacific in the June 1, 2007 request for an applicability determination for Boiler B25 under the CAIR trading programs and supplemental submissions by Georgia Pacific on August 23, October 18, and November 1, 2007, February 13, April 4, and June 24, 2008, December 11, 2009, and March 23, April 22, and November 23, 2010 and February 4, 2011. The determination is appealable under 40 CFR part 78. If you have any questions regarding this determination, please contact Louis Nichols at (202) 343-9008. Thank you for your continued cooperation.

Sincerely,

Sam Napolitano, Director
Clean Air Markets Division

cc: Constantine Blathras, EPA Region 5
Andy Seeber, WDNR