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February 9, 2007

Mr. Terry O'Clair
North Dakota Department of Health
Division of Air Quality
918 East Divide Avenue, 2nd Floor
Bismarck, ND 58501-1947

**RE: Response to NDDH Information Request for the BART Analysis
Great River Energy – Stanton Station
Permit: T5-F76007**

Dear Mr. O'Clair:

Great River Energy (GRE) submits this letter in response to the North Dakota Department of Health's (NDDH) December 1, 2006 request for additional information regarding the Best Available Retrofit Technology (BART) Analysis for Stanton Station. To address certain Environmental Protection Agency (EPA) and National Park Service (NPS) comments, NDDH requested information pertaining to issues regarding 98% SO_2 control, additional control technology evaluations, and combustion optimization systems. For clarity, the three original NDDH comments are restated before each response.

NDDH Comment #1

The National Park Service has indicated that 98% SO_2 control has been proposed on several other projects such as Thoroughbred, LGE-Trimble and Mustang. Although the Department recognizes that such sources have not been built and that they will be firing coal not common to our region, we ask that Great River Energy provide comments on this issue.

GRE Response to Comment #1

The issue of 98% SO_2 control has also been raised with regard to other regulatory programs, such as NSPS and New Source Review BACT determinations. It is important to note that 98% has been 'proposed' (emphasis added) under other regulatory programs, and may be appropriate under certain operational conditions, but it has not been consistently demonstrated under all operational conditions. Some specific examples of other regulatory programs are included below.

In the February 27, 2006 Federal Register 40 CFR 60 Final Rule for Electric Generating Units (EGU), EPA expressly addressed the issue of 98% SO_2 on page 9870 in its response. EPA recognizes that "98% control is possible with certain control and boiler configurations." However, EPA sets the recent NSPS limit at 95% control for new unit wet scrubbing technologies to reflect "variability that occurs with non-ideal operating conditions[1]." Again, while 98% may be achievable, it should neither be used for estimating annual emission reductions nor determining 30-day rolling emission limits under the BART rule.

Similar to EPA, the Electric Power Research Institute (EPRI) has evaluated SO_2 scrubber performance and reaches essentially the same conclusion. EPRI considered 66 recently permitted BACT/LAER units at 50 facilities. Their analysis supports 95% control as reasonably achievable for wet scrubbers for recently installed units. Thirty two of the evaluated units were PC boilers. Of the 66 total units, only 17 are currently operational.[2]

The EPRI evaluation includes electronic data reporting (EDR) information for the majority of recently constructed and operational BACT sources. As potentially relevant to Stanton Station's Unit 1 pulverized coal (PC) boiler, Table 1 contains a summary of the data presented for the two PC boilers that were included in the EDR analysis. The data illustrate that there are significant problems meeting proposed BACT limits. Similar issues are noted with the operational CFB boilers in EPRI's evaluation.

Table 1. EDR Analysis Summary for PC Boilers

Unit	SO_2 Limit (lb/MMBtu)	Fuel	Boiler Rating (MMBtu/hr)	30-Day Block Average Comparison		
				Above Limit	At Limit	Below Limit
Hawthorn Unit 5	0.12	PRB Coal	6,000	19	4	29
Wygen Unit 1	0.17	PRB Coal	1,300	2	0	30

[1] *40 CFR 60 - Standards of Performance for Electric Utilities Steam Generating Units, Industrial-Commercial-Institutional Steam Generating Units, and Small Industrial-Commercial-Institutional Steam Generating Units; Final Rule.* 72 FR 9870

[2] *Status and Performance of Recently Permitted BACT/LAER Plants*, EPRI, Palo Alto, CA: December 2006. 1013346

The National Park Service references certain specific BACT permitting decisions as evidence of 98% control feasibility. The EPRI study appropriately addresses these specific decisions, namely Thoroughbred and Trimble generating stations. (Mustang was excluded from the EPRI study because their application is still pending and should not be considered.) As noted in the EPRI study, the proposed limit for Thoroughbred is 0.167 lb/MMBtu on a 30-day rolling average basis. Notably, this emission rate for a new unit is higher than the presumptive BART limit of 0.15 lb/MMBtu. Thoroughbred also has a 0.41 lb/MMBtu on a 24-hour maximum basis. The Trimble permit has a calculated limit of 0.11 lb/MMBtu. While these proposed limits suggest 98% control, the EDR information available for similar boilers, as previously noted, indicates that such a degree of control cannot be consistently achieved and should not be considered as the basis for a permit limit.

In summary, 98% control has been used as part of permitting negotiations or can potentially be considered under certain "ideal" operational scenarios for new units. However, consistent with EPA and EPRI determinations, 98% control has not been proven as a valid basis for setting 30-day limits for new units and should not be considered for retrofit applications, like Stanton Station Unit 1. Stanton Station has appropriately applied 90% and 95% SO_2 control estimates for dry and wet scrubbing technologies, respectively, as a basis for evaluating technically feasible BART technologies and, more importantly, for deriving the proposed SO_2 emission limit that is expressed as a 30-day rolling lb/MMBtu value. The proposed BART limit reflects both ideal and non-ideal operational scenarios including fuel sulfur variations that are expected over the life of the plant.

NDDH Comment #2

For SO_2 controls, a circulating dry scrubber and a flash dryer absorber were not included as potential control technologies. For NOx, rotating over-fire air (ROFA) was not included as a potential control technology. These technologies appear to be technically feasible and we ask that you address these control technologies.

GRE Response to Comment #2

Each of the three aforementioned technologies is addressed below for Stanton Station Unit 1.

<u>Circulating Dry Scrubber (CDS)</u>

TurboSorp® is a common type of CDS. TurboSorp was evaluated in Stanton's initial BART submittal as a novel control. (See excerpt from Stanton's BART Analysis pg. 30).

> TurboSorp® is a dry FGD technology in which the flue gas is pushed through an open chamber reactor. The flue gas enters the reactor through a nozzle with venturi geometry for optimum distribution of gas flow. The fluidized bed of particles circulates above the venturi inlet inside the vessel and water is injected to maintain outlet temperatures in the range of 45°F to 55°F above saturation temperature. Recycled particles from the baghouse along with hydrated lime are injected at this location to control outlet SO_2. The stream is then passed through a fabric filter or ESP to remove large particulate before discharge through the stack.
>
> A booster fan would be required at the outlet to control the gas flow rate. The system would also require installation of a hydrator or pug mill to facilitate the lime hydration process. Test plants are currently operating in Europe, but TurboSorp® has not been commercially demonstrated in the United States. Though not considered technically feasible due to its lack of commercial availability at this time, TurboSorp® may be considered in future control technology assessments as GRE evaluates BART implementation.

While the manufacturer's title, TurboSorp, is different, the control technology concept is identical. Operating experience with CDS systems is fairly limited in the U.S, making this a novel technology as applied to existing units.

Flash Dryer Absorber (FDA)

The FDA represents another form of spray dry technology. It utilizes a thin film, as opposed to a slurry, to partially saturate the flue gas and capture SO_2. This technology is proprietary to Alstom Power and has been commercially demonstrated in the U.S. on only circulating fluidized bed boilers. Alstom Power provides a list of all US and international installations in Attachment A. This list shows that, while this technology is technically feasible for PC boilers outside of the US, there are only two PC installations that achieve 80% SO_2 removal. This represents an available degree of control less than the proposed 90% removal from dry scrubbing currently proposed for Stanton Station. This technology has not been commercially demonstrated in the U.S. for use on PC boilers. Therefore, no further analysis for BART is necessary.

Rotating Opposed Fire Air (ROFA)

ROFA technology is proprietary to Mobotec. ROFA is categorized by the air nozzles and ROFA boxes that are asymmetrically positioned within the boiler. A booster fan is used to inject high pressure overfire air into the boiler, causing the combustion gas to mix with added air.[3] Some degree of rotation is inherent in the short fire-box design at Stanton Station.

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[3] MobotecUSA (http://www.mobotecusa.com/technology/rofa.htm) DOA 10JAN2007.

As discussed in the BART analysis (pg.22), Stanton Station Unit 1 has a relatively short fire box, which makes any assessment of OFA or ROFA extremely difficult. OFA components are usually designed and operated in conjunction with low NOx burners as a comprehensive system. Stanton Unit 1 installed Alstom LNB in 1999. Therefore, it is both appropriate and necessary to use Alstom as the most qualified vendor to assess OFA technology for Stanton Unit 1. (See Alstom Report, NOx Reduction Technologies, which was attached to Stanton's BART Analysis.) Any ROFA reductions beyond the Alstom OFA estimates would be purely speculative. They could not be determined with any accuracy without detailed engineering analyses, including computational fluid dynamic (CFD) modeling of the boiler, which is beyond the scope and time frame of the BART process.

GRE has met with Mobotec representatives and considers ROFA as a viable OFA technology. GRE may continue to evaluate Mobotec's ROFA as the plant moves forward with more detailed engineering analysis. Based on the information submitted and our analysis of the ROFA technology, we would not expect any significant changes to either the control costs or the projected emission reductions that would influence the technology determination or change the proposed NOx emission limit.

NDDH Comment #3

We ask that you address the use of combustion optimization systems (COS) for the reduction of NOx emissions.

GRE Response to Comment #3

While COS have not been explicitly evaluated for Stanton Station, they are inherent to any installation of LNB and OFA. GRE has proposed OFA as the BART technology for NOx control. Combustion optimization through burner tuning and air flow balancing to maximize the performance of the LNB and OFA system are integral to its implementation.

Boiler operators track many variables, such as fouling, slagging, loss on ignition (LOI), oxygen levels, temperature, and stack emissions data from the continuous emissions monitoring system (CEMS) as indicators of combustion optimization. Since fuel is the most costly variable expense, operators are continuously tracking performance variables and adjusting operations to improve efficiency.

It was mentioned in BART-related correspondence to the NDDH that neural networks can provide significant NOx reductions at a low cost. Artificial neural networks are potentially more economical for new units that are relatively automated. They are also considered at existing units, especially in cases where a CEMS has not been utilized. In the absence of CEMs, the neural network helps

GRE with the necessary emissions and operations data to enable tuning of the boiler's combustion characteristics.

Although the use of neural networks can provide more instantaneous parameter changes during load swing, Unit 1 is not expected to significantly and frequently vary in its heat duty and steam load. Further, the proposed BART technology for NOx control will employ OFA with integral combustion optimization and tuning, which in conjunction with the CEMS, will provide for appropriate NOx emissions reductions as the BART control technology.

If you have any questions regarding this letter, please contact Greg Archer at (763)241-2278.

Sincerely,

GREAT RIVER ENERGY

Mary Jo Roth

Mary Jo Roth
Manager, Environmental Services

c: S. Smokey, GRE – SS
B. Johnson, GRE – SS
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Attach.

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Attachment A

Alstom Power's Flash Dryer Absorber (FDA) International Installations

Alstom Reference List

Air Pollution Control Systems for DFGD

Owner/Operator Name	Plant/Unit Name	Location	Country	Capacity Power [MW]	Capacity Gas Flow [Nm3/h]	SO2 Efficiency	Start Up Date	Process Description	ppm Sulphur
Elektrownia Laziska	Laxiska Unit 1 & 2	Laziska	PL	2 x 120	1,036,000	80%	1996	Flash Dryer Absorber	1000.0
EWAG	Sandreuth, # 3	Nuremberg	DE	53	168,200	95%	1999	Flash Dryer Absorber	850.0
AES Corporation	Fifoots Units 1-3	Fifoots Point	UK	3 x 125	1,350,000	80%	2000	Flash Dryer Absorber	700.0
Juhua Group Co.	Zhejiang #8	China	CN	70	330,000	85%	2000	Flash Dryer Absorber	1100.0
Hailong Paper Co.	Dong Guan, #5	China	CN	70	300,000	90%	2003	Flash Dryer Absorber	1300.0
Jiangyin TPP	Jiangying Thermal Power Plant, #3	China	CN	70	266,315	90%	2003	Flash Dryer Absorber	1500.0
Jiulong (Taicang) Paper Co.	Taicang	China	CN	135	435,000	90%	2003	Flash Dryer Absorber	1000.0
Baotou No 2 TPP	Baotou #2	China	CN	200	791,000	90%	2004	Flash Dryer Absorber	1000.0
Hua Ying Shan Power Plant	Hua Ying Shan Power Plant # 4	China	CN	100	450,000	90%	2004	Flash Dryer Absorber	1000.0
JCS Lithuanian Power Station	Elekternai # 8	Lithuania	LI	150	520,000	95%	2004	Flash Dryer Absorber	2275.0
Jingmen P.P.	Jingmen Power Plant, #4	China	CN	200	865,000	85%	2004	Flash Dryer Absorber	1000.0
Jiulong Paper Co.	Dong Guan	China	CN	210	799,840	90%	2004	Flash Dryer Absorber	1500.0
Shengyang TPP	Shengyang Thermal Power Plant, #3	China	CN	50	309,000	85%	2004	Flash Dryer Absorber	1200.0
Xinwang P.P.	Xinwang Power Plant, #1 & 2	China	CN	2 x 135	990,000	90%	2004	Flash Dryer Absorber	1100.0
Jiulong Paper Co.	Dong Guan #6	Guangdong	China	210	799,840	90%	2005	Flash Dryer Absorber	655.0
QiLu Power Plant	Zibo #7 & 8	China	CN	2 x 100	990,000	90%	2005	Flash Dryer Absorber	821.0
SPDC	Mindanao IPP, #1 & 2	Philippines	PH	2 x 105	940,000	80%	2005	Flash Dryer Absorber	850.0
Hemei Group	Heibi Power Plant #1	Henan	China	2x135	1,099,000	85%	2006	Flash Dryer Absorber	260.0
Juhong TPP	Juhong	Zhejiang	China	135	505,000	90%	2006	Flash Dryer Absorber	930.0
Taizhou P.P.	Taizhou #6	Zhejiang	China	135	596,000	85%	2006	Flash Dryer Absorber	700.0
Yima	Yima Environmental Protection Power Plant	Henan	China	78	340,000	90%	2006	Flash Dryer Absorber	960.0
Shenhai Cogen	Shenhai	Shenyang	China	200	890,000	90%	2006	Flash Dryer Absorber	1428.0

Highlighted units are PC boilers.

Last Updated: July, 2006